EGI Asset Management Plan Addendum - 2020

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Company: Enbridge Gas Inc.

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EGI Asset Management Plan Addendum - 2020

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1 Introduction

1.1 BACKGROUND

Enbridge Gas Inc.'s (EGI) two predecessor companies, Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (UGL) filed Asset Management Plans (AMPs) for the period 2019-2028 in EGI's 2019 rates filing (*EB-2018-0305*) at *Exhibit C1, Tab 2, Schedule 1* and *Exhibit C1, Tab 3, Schedule 1*.

This addendum aims to provide an update to budget year 2020 for each for the two Asset Management Plans. This addendum is not a standalone document – it should be reviewed in conjunction with the two previously filed AMPs (see **Appendix A: EGD Rate Zone Asset Management Plan 2019 - 2028** and **Appendix B: Union Rate Zones Asset Management Plan 2019 - 2028**).

EGI is focusing efforts to work towards an integrated Utility System Plan (USP) and Asset Management Plan for its 2021 rates filing – noting that the assets for the two rate zones (the EGD Rate Zone and the Union North and South Rate Zones) will be maintained separately for capital planning purposes for at least the duration of the deferred rebasing period. Each rate zone has its own rate base and rates, as well as separate materiality threshold calculations, as described in Exhibit B, Tab 2, Schedule 1.

This approach is further described in the USP for 2019 rates (*EB-2018-0305, Exhibit C1, Tab 1, Schedule 1,Page 3*):

> *As Enbridge Gas works through the integration of the two utilities, components of the Enbridge Gas USP and the AMPs are, and will continue to be separate. As discussed above, Enbridge Gas expects to be able to file an update to the Enbridge Gas USP and AMPs which reflects a further integrated utility with any ICM funding requests for 2021 rates and beyond. Fundamentally however, strong asset management that balances cost, risk and performance, while delivering value to customers has been at the core of EGD and Union's business for years and is demonstrated throughout the Enbridge Gas USP and AMPs. Enbridge Gas's USP meets the needs of the utility's customers of the EGD and Union rate zones through strong asset management that supports the delivery of safe, reliable service.*

The principles outlined in each of the AMPs have not changed and the identified asset life cycle strategies have no material changes. Needs and investments have emerged since the AMPs were filed in December 2018, and new information has been acquired for some projects, requiring an ongoing review of investments and timing – including those for 2020.This process, a budget refresh for 2020, is detailed in **Section 1.2**. The existing 2020 capital filed in the AMPs was used as a base and changes were identified by exception.

Examples of emerging needs, investments, or changes for the EGD Rate Zone in the 2020 budget year include the following: the addition of a new Clarington to Cathcart Integrity Retrofits project, the exclusion of the NPS 20 Don River Relocation based on the assumption that it is 100% rebillable, and the deferral to confirm scope and timing of the Corunna (SCOR) Meter Area Upgrade project.

For the Union Rate Zones, examples of emerging needs and investments, or changes for the 2020 budget year include the following: the Waubuno Pool project where pre-spend capital was moved from 2020 to 2021, the addition of the 2021 Kirkwall Hamilton NPS 48 project, additional integrity work, the shift of Kingsville project costs[1] to 2020 and the deferral of the Sarnia Industrial Line Reinforcement project[2] to 2021.

Two additional ICM-eligible projects have been identified through the 2020 budget refresh process. For the EGD Rate Zone, the NPS 20 Lakeshore KOL Replacement project has pre-spend dollars in 2020. For the Union Rate Zones, the 2021 year in-service Kirkwall to Hamilton NPS 48 Dawn to Parkway project has pre-spend dollars identified in 2020. The previously identified ICM-eligible Sarnia Industrial Line Project was revised to three separate ICM-eligible projects (shown in **Table 2.2-3**).

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[1] *For the Kingsville Transmission Reinforcement project, $13.2M has been shifted from 2019 to 2020. For the purposes of determining Maximum Eligible ICM capital, the 2020 capital amount for Kingsville is excluded from the 2020 in-service capital budget as the total project cost has been approved for ICM in 2019 rates.*

[2] *The Sarnia Industrial Line project was previously identified as a single larger project in the AMP. Three separate projects have since been identified to replace the single project, included in Table 2.2-3. The first of these projects is the 2021 Sarnia Industrial Line Reinforcement.*

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ICM-eligible projects were identified in the previously-filed USP at *Exhibit C1, Tab 1, Schedule 1, page 49*, *Table 6*. An updated table is provided in evidence in **Table 2.1-2** for the EGD Rate Zone and **Table 2.2-2** for the Union Rate Zones. One point to note is that the NPS 30 Don River Replacement Project previously identified as 2019 in-service project was delayed to 2020 in-service and will be considered as ICM-eligible in 2020.

Subsequent to the 2020 budget refresh process, further changes were made to the 2020 budget to reflect impacts of the Board's Decision in the 2019 rates case *(EB-2018-0305)*. This included an increase to the EGD Rate Zone customer attachment capital of $18.5 million to reflect reverting to the prior customer service policy and the exclusion of forecast Contribution in Aid of Construction (CIAC). Technology and Information Services-related projects found by the Board to be premature in the 2019 capital plan have been removed for 2020 as well. Specifically, the HANA software upgrade of $4.0 million has been removed from the budget.

The total capital spend for EGI for the 2020 budget year including Overheads and ICM-eligible investments is $1031.6 million. The EGD rate zone portfolio total is $485.2 million and the Union rate zone portfolio total is $546.4 million. See **Table 1.1-1** for a summary of the high-level portfolios of planned capital investments. Other than the emerging and changing items noted above and impacts from the *EB-2018-0305 Decision*, there are limited changes for 2020 compared to the AMPs filed in the 2019 Rates proceeding. Each portfolio has been reduced compared to the AMPs. Further breakdown of each portfolio by asset category, with descriptions, and comparisons to the previously filed 2020 portfolios are provided in **Section 2.1** for the EGD Rate Zone and **Section 2.2** for the Union Rate Zones. Capital expenditures were previously filed in the 2019 rate application (*EB-2018-0305*) at *Exhibit C1, Tab 1, Schedule 1 Figures 6,7, and 8*.[3]

Table 1.1-1: Summary of 2020 Capital Spend - EGD Rate Zone, Union Rate Zone and total EGI (Includes Overheads)

2020 Budget	EGD Rate Zone	UG Rate Zone	Total EGI
General Plant	46.8	52.0	98.8
System Access	141.5	96.0	237.5
System Renewal	136.9	191.5	328.4
System Service	13.4	128.5	141.9
Total Overheads	146.5	78.4	225.0
TOTAL	485.2	546.4	1031.6

(costs expressed in millions of Canadian dollars)

1.2 BUDGET PROCESS FOR 2020

The process undertaken to review and prepare the 2020 budget ('budget refresh') for both legacy utilities was completed manually, based on the existing 2020 budget year of the 10-year AMPs, done on an exception basis. This process is similar to the annual asset management governance process used to manage the budget throughout the year.

The existing AMPs were used as a starting point for the capital investment portfolios in each rate zone. Asset Managers for each asset class identified changes to the capital requirements due to emerging needs, changing circumstances, potential for deferral, project execution risk, or other drivers. All requests for emerging or revised projects were supported with clear purpose, need, and timing, to allow for evaluation. An overall review was undertaken to understand various project uncertainties and ensure that as much risk and opportunity is addressed as possible in the 2020 budget year within the constraints of the two rate zones.

[3] *Note that figures provided in the USP included community expansion costs. These costs have been excluded from the budget figures presented in this addendum as they do not form part of base capital.*

This is consistent with preparation of budgets within the 10-year AMP, as noted in the Union Rate Zones AMP at *Exhibit C1, Tab 3, Schedule 1 Section 4.2.1.1.4 (Prioritization and Selection)*:

> *The 10-year AMP is used as the starting point for the annual capital budget process, which determines the budget for the following year. Through the budget preparation process, the risks that each project is mitigating are re-evaluated and endorsed. It is at this point that new projects may also be identified to mitigate risk.*

It is also consistent with EGD Rate Zone AMP principles, as noted in *Exhibit C1, Tab 2, Schedule 1, Page 87 of 1459*:

> *EGD acknowledges that the identification of risks and the execution of projects is dynamic. As a result, the portfolio is reviewed twice following optimization, to account for execution status, outstanding risks and opportunities, and emerging risks and opportunities. During the year, the project scope may change or new projects may arise, resulting in cost pressures to the current portfolio. As these pressures are identified, trade-off decisions are made based on risk and available capital, a direct demonstration of EGD's Plan-Do-Check-Act model.*

This process of identifying emerging needs, responding to project delays, and addressing the changing needs of the business is ongoing through the course of the year. **Figure 2.1-1** and **Table 2.1-2** in this Addendum note changes that occurred in each of the portfolios.

Evaluation also included determining the degree to which changes can be accommodated by the allowed capital investment for each rate zone as well as to test if there is capacity to bring previously identified ICM-eligible projects inside the base. As referenced in the rates evidence at Exhibit B, Tab 2, Schedule 1, the materiality thresholds have been revised based on the defined calculations and also to reflect the *EB-2018-0305 Decision*.

The approval process for the 2020 budget included the following steps:

1. Asset Managers sign off on business cases submitted
2. Review by Asset Managers, Finance, and Subject Matter Advisors (to confirm portfolios for 2020 for each rate zone)
3. Review by Asset Management Steering Committee
4. Review and sign-off by Director, Asset Management
5. Review and sign-off by VP Engineering
6. Approval of 2020 Budget by EGI President
7. Approval of 2020 Budget by Enbridge Board

Based on the process described, and given the limited nature of the changes to the 2020 investments and the reduction in the overall portfolios, no optimization was required to be run for the EGD Rate Zone 10-year AMP. The optimization process was recently completed for the 10-year period (2019-2028) in the fall of 2018, and was reviewed as part of the 2019 rates proceeding. The 2020 budget year was included in that optimization process and it has only been a short period of time since this work was completed.

The optimization process will be completed in 2020 for each of the EGD Rate Zone and Union Rate Zones 10-year plans to support the integrated 2021 USP and AMPs, as it is a significant undertaking to begin to integrate the processes.

As noted above, additional adjustments were made to the 2020 budget to reflect the outcomes of the Board's Decision in the 2019 rates case *(EB-2018-0305)*.

2 Summary of Capital Expenditures

2.1 ENBRIDGE GAS DISTRIBUTION (EGD) RATE ZONE

As discussed in **Section 1.2**, emerging and revised projects were identified and evaluated based on the existing 2020 portfolio. No changes have been reflected to future year portfolios, as such, no updates were required to the assumptions in **Section 6.4** of the EGD Rate Zone AMP. No changes were made to inflation assumptions for future year projects. Updated cost estimates were prepared for new or revised 2020 projects, but no changes were made to existing projects included in the AMPs as filed. Projects with solution scopes still under development are not included in the 10-year portfolio of spend.

Table 2.1-1: 2020 EGD Capital portfolio (including ICM) and Variance Explanations

ASSET CLASS	2020 AMP	PROPOSED 2020 PORTFOLIO	VARIANCE	VARIANCE EXPLANATION
Business Development	6,917,510	3,003,739	(3,913,771)	**Increase** 1. Cost for establishing hydrogen interoperability criteria. Materials and services for hydrogen injection station moved from 2019 to 2020, and increased (+$1.6M) **Decrease** 1. Reclassified CNG (NGV rental compressors) to unregulated capital (-$5.6M)
Customer Assets	43,630,813	34,279,567	(9,351,246)	**Decrease** 1. 2020 meter purchase cost decrease and advancement of meter purchases into 2019 (-$9.1M)
Customer Growth	102,530,085	121,030,085	18,500,000	**Increase** 1. Increase due to OEB Decision on Customer Growth Policy (CIAC refund) and resulting impact on customer attachment forecast (reflecting increase of 1900 forecast attachments) (+$18.5M)
Fleet & Equipment	6,610,408	8,610,408	2,000,000	**Increase** 1. Increase to align rate zone approaches (+$2.0M)
Technology & Information Services	22,495,000	15,145,000	(7,350,000)	**Increases** 1. Multiple project increases due to scope changes (+$0.575M) **Decreases** 1. Decrease in Desktop Replacement due to advancement of costs into 2019 for Windows 10 operating compliance (-$1.5M) 2. Decrease in Operation Digital due to scope adjustment (-$1.5M) 3. Various small projects deferred (-$0.925M) 4. HANA Software Upgrade removed based on OEB Decision (-$4.0M)
Pipe	96,012,837	90,292,494	(5,720,343)	**Increases** 1. NPS 8 Clarington to Cathcart Integrity Retrofit (+$5.2M). 2. NPS 8 Blackburn Extension deferred from 2019 to 2020 (+$3.5M).

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ASSET CLASS	2020 AMP	PROPOSED 2020 PORTFOLIO	VARIANCE	VARIANCE EXPLANATION
Pipe *(continued)*				3. NPS 30 Don River Replacement in-service delayed to 2020, shifting cost from 2019 to 2020 (+$3.5M) 4. Integrity Digs (+$3.0M). 5. 2020 Steel Replacement Program (+$3.0M). 6. NPS 20 Lakeshore KOL Replacement (+$1.9M) 7. Sideline 16 and Brock Pressure Control Station (+$0.95M) **Decreases** 1. NPS 20 Don River Relocation reduced, as 100% rebillable ($22.0M) 2. Welland IP NW8925 Reinforcement is deferred to 2030 (-$0.8M) 3. L'Original Reinforcement is deferred to 2026 (-$3.9M)
Real Estate and Workplace Services	19,678,287	23,074,798	3,396,511	**Increases** 1. Kennedy Road Expansion land purchase moved forward from 2022 to 2019 and 2020 (+$2.2M) 2. Brampton Operations Centre cost increase (+$1.7M). 3. TIS Tech & Innovation Lab to support creating high value applications (+$1.0M). 4. VPC Floor 1 Renovation cost increase (+500K). **Decreases** 1. Advanced furniture and material purchase for VPC Floor 1 Renovations into 2019 (-$2.0M).
Stations	27,749,648	23,658,443	(4,091,205)	**Increases** 1. Station B retrofit for integrity (+$1.2M). 2. Capacity-related rebuilds (+$400K). **Decreases** 1. Campbell St. District deferred to 2021, scope and timing review (-$1.9M). 2. Jonesville feeder regulation run rebuild items identified as a priority and advanced for 2019 completion (- $1.1M). 3. St. John's Feeder: advancement of land purchase to 2019 (-$1.0M). 4. Harmer District Station project deferred to 2021 (-$1.7M).
Storage	33,973,589	19,560,581	(14,413,008)	**Increases** 1. Corunna Storage Renewal FEED study deferred from 2019 (+$2.5M). 2. Integrity digs (+$1.02M). **Decreases** 1. SCOR Meter Area Upgrade deferred to confirm scope and timing- moved $18.0M from 2020 (-$18.0M)
Base Capital + ICM Total	**359,598,177**	**338,655,115**	**(20,943,062)**	
Overheads	**154,024,768**	**146,544,956**	**(7,479,812)**	

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ASSET CLASS	2020 AMP	PROPOSED 2020 PORTFOLIO	VARIANCE	VARIANCE EXPLANATION
Grand Total	**513,622,945**	**485,200,071**	**(28,422,874)**	

The updated capital spend (excluding overheads) for 2020 for the EGD rate zone is $338.7 million. This compares to the previously filed EGD Asset Management Plan capital of $359.6 million. The decrease of $20.9 million is driven mainly by the deferral of the SCOR meter yard project spending of $18.0 million, a reduction due to the NPS 20 Don River Relocation to be treated as 100% rebillable, and TIS reductions, partially offset by the increase in customer growth spend due to OEB Decision on customer attachment policy.

Figure 2.1-1 shows the comparison between the 2020 EGD AMP budget figures and the proposed 2020 portfolio.

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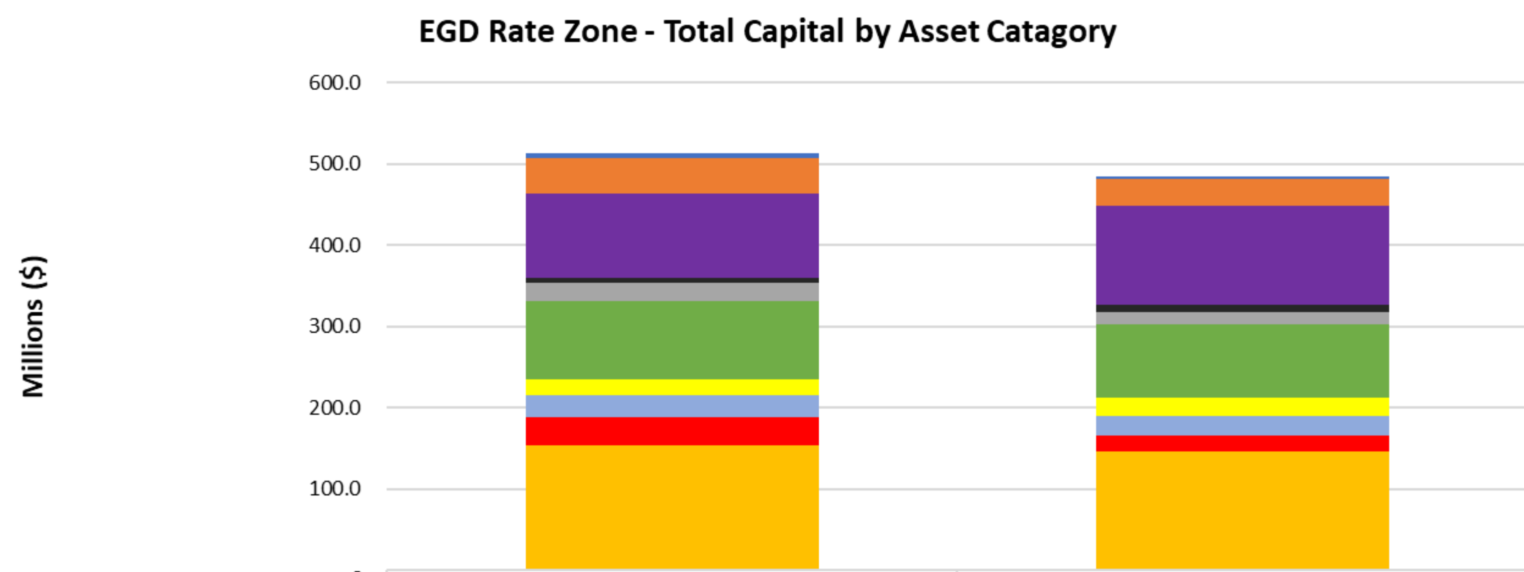

	2020 AMP	Proposed 2020
Business Development	6.9	3.0
Customer Assets	43.6	34.3
Customer Growth	102.5	121.0
Fleet & Equipment	6.6	8.6
Information Technology	22.5	15.1
Pipe	96.0	90.3
Real Estate and Workplace Services	19.7	23.1
Stations	27.7	23.7
Storage	34.0	19.6
Overheads	154.0	146.5

Figure 2.1-1: **EGD Rate Zone 2020 AMP Budget and Proposed 2020 Portfolio Comparison**

Table 2.1-2 shows the list of Potential ICM projects for the EGD Rate Zone Portfolio.

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Table 2.1-2: EGD Rate Zone ICM-eligible Projects

ASSET CLASS	INVESTMENT CATEGORY	PROJECT NAME	IN-SERVICE YEAR
Pipe	System Renewal	NPS 30 Don River Replacement	2020
Pipe	System Renewal	NPS 20 Don River Relocation	2021
Storage	System Renewal	SCOR: Meter Area Upgrade[4]	2021
Pipe	System Renewal	NPS 12 St. Laurent Ottawa North Main Replacement	2022
Pipe (NEW)	System Renewal	NPS 20 Lakeshore KOL Replacement	2022
REWS	General Plant	Kennedy Road Expansion	2022
Pipe	System Renewal	NPS 12 Martin Grove Road Main Replacement Phase 2	2024
REWS	General Plant	VPC Core and Shell Improvements	2025
REWS	General Plant	SMOC/Coventry Consolidated Facility	2026

Table 2.1-3 shows the forecast costs for the potential ICM projects in the EGD Rate Zone portfolio.

Table 2.1-3: EGD Rate Zone ICM-eligible Projects: Forecast Costs

PROJECT NAME	2019F	2020	2021	2022	2023	2024
NPS 12 St. Laurent Ottawa North Main Replacement [5](2021+)	-	150,000	9,589,682	40,641,901	1,900,000	-
NPS 30 Don River Replacement	19,596,987	4,266,583	-	-	-	-
NPS 20 Don River Replacement[6]	-	-	-	-	-	-
NPS 20 Lakeshore KOL Replacement (Cherry to Bathurst) (2019+) (NEW)	-	3,500,000	130,613,276	31,132,437	8,400	-
SCOR: Meter Area Upgrade	8,500,000	-	35,100,000	-	-	-

[4] *Scope under review.*
[5] *This project is before the OEB in a Leave to Construct, where it is proposed to move a portion of this project forward. Any updates will be reflected in 2021 AMP.*
[6] *Cost adjusted to zero based on 100% rebillable assumption.*

PROJECT NAME	2019F	2020	2021	2022	2023	2024
VPC Core and Shell Improvements					10,000,000	10,000,000
Kennedy Road Expansion	7,000,000	2,200,000	8,000,000	4,500,000		
NPS 12 Martin Grove Road Main Replacement Ph2					400,000	10,750,000
Grand Total	**35,096,987**	**10,116,583**	**183,302,958**	**76,274,338**	**12,308,400**	**20,750,000**

Business cases for each of the emerging projects and other noted changes can be found in **Appendix C: List of EGD Rate Zone Business Cases**.

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2.2 UNION RATE ZONES

As discussed in **Section 1.2**, starting from the existing 2020 portfolio, emerging and revised projects were identified and evaluated. No changes have been reflected to future year portfolios, as such, no updates were required to the assumptions in **Section 6.5** of the Union Rate Zones AMP. No changes were made to inflation assumptions for future year projects. Updated cost estimates were prepared for new or revised 2020 projects, but no changes were made to existing projects included in the AMPs as filed.

Table 2.2-1: 2020 Union Rate Zones Capital portfolio (including ICM) and Variance Explanations

LEGACY ASSET CLASS	NEW ASSET CLASS	2020 AMP	PROPOSED 2020 BUDGET	VARIANCE	VARIANCE EXPLANATION
Underground Storage	Transmission Pipe & Underground Storage	2,141,671	8,585,496	6,443,825	**Increases** 1. Additional project: Kirkwall - Hamilton NPS 48 (+$4.6M) 2. New injection/withdrawal well at Payne (+$2.5M) 3. Wellhead Upgrade project cost increase (+$0.178M) **Decrease** NPS 36 Line Valve Operator Replacement (-$0.842M)
Fleet	Fleet & Equipment	12,000,000	8,944,218	(3,055,782)	**Increase** 1.Tools purchases re-classified and moved to Fleet (+$1.94M) **Decreases** 1. Advance of Vehicle Purchases from 2020 to 2019 (-$3.0M) 2. $2.0M reduction to align rate zone approaches (-$2.0M)
Compression & Dehydration	Compression & Dehydration	9,035,358	5,545,498	(3,489,860)	**Increases** 1. New risk-based projects (+$1.0M) • Dawn Dehydration Plant Tank Replacement (+$0.684M) • Dawn Aux Boiler Replacement (+$0.314M) 2. Updated cost estimates for various projects(+$1.1M) **Decreases** 1. Engine overhauls required in later years due to changes in operational usage (-$1.9M) 2. Waubuno Pool project deferred (-$3.2M) 3. Tools moved to Fleet & Equipment portfolio (-$0.311M)
CRES	REWS	15,000,000	11,600,096	(3,399,904)	**Decreases** 1. Belleville building construction moved to 2021 (-$3.2M) 2. Multiple small project cost reductions (-$0.2M)
Stations	Distribution Stations	24,259,433	19,249,957	(5,009,476)	**Increases** 1. Bristol 3330 Replacement Program based on risk assessment – reclassified from Measurement (+$3M), renamed and increased for a total change of (+$4.3M)

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LEGACY ASSET CLASS	NEW ASSET CLASS	2020 AMP	PROPOSED 2020 BUDGET	VARIANCE	VARIANCE EXPLANATION
Stations *(continued)*					2. Reclassification of Odourant Upgrades from Measurement to Stations (+$1.4M) 3. Other small project changes (+$0.5M) **Decreases** 1. Regulators and reliefs reclassified under Utilization (-$8.9M) 2. Stations Capital Maintenance blanket removed; projects defined (-$2.1M) 3. Reduction in Frost Heave & Odourant Upgrades programs (-$0.2M)
Measurement	Utilization	34,906,277	33,639,115	(1,267,162)	**Increase** 1. Reclassification of regulators & reliefs from Stations to Measurement/Utilization (+$8.9M) **Decreases** 1. Odourant Upgrades cost decrease due to reclassification to Stations(-$1.4M). 2. Replacement of Obsolete RTUs renamed as Bristol 3330 and reclassified to Stations (-$3.0M). 3. Advance of 2020 meter purchases into 2019 (-$5.4M)
TIS	TIS	31,255,625	30,955,664	(299,961)	**Decrease** 1. Open Plant/Plant Space project deferred (-$0.3M).
Pipelines	Distribution Pipe	186,760,460	215,394,407	28,633,947	**Increases** 1. Integrity program increased due to additional integrity digs above forecast and other changes (+$11.5M) 2. Additional Bruce Lake integrity work identified in 2020 (+$8.6M) 3.Class location program increased (+$0.80M) 4. Advancement of Byron Transmission into 2021 (+$0.4M) 5.Kingsville Transmission Reinforcement costs shifted[7] to 2020 (+$13.2M) and reclassified from Growth to Distribution Pipe (+2.8M) for a total change of (+$16.0M) **Decreases** 1. Mains Replacement program decreased (-$4.0M) 2. Tools reclassified to Fleet & Equipment portfolio (-$1.3M) 3. Windsor Line cost estimate decreased for 2020 (-$5.1M)
LNG		21,224	-	(21,224)	**Decrease** 1. Reduction due to advancement of 2020 projects to 2019 (-$0.21M).

[7] *For the purposes of determining Maximum Eligible ICM capital, the 2020 capital amount for Kingsville is excluded from the 2020 in-service capital budget as the total project cost has been approved for ICM in the 2019 rates filing.*

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LEGACY ASSET CLASS	NEW ASSET CLASS	2020 AMP	PROPOSED 2020 BUDGET	VARIANCE	VARIANCE EXPLANATION
					*LNG projects to be included in Compression & Dehydration.
Growth	Growth	198,283,189	134,087,137	(64,196,052)	**Decreases** 1. Deferral of Sarnia Industrial System Project[8] (-$59.2M) 2. CK Rural project government contribution (-$3.7M) 3. Reclassification of Kingsville Transmission from Growth to Distribution Pipe (-$2.8M)
Base Capital + ICM Total:		**513,663,237**	**468,001,588**	**(45,661,649)**	
Overheads		**80,000,000**	**78,406,892**	**(1,593,108)**	
Grand Total		**593,663,237**	**546,408,480**	**(47,254,757)**	

Note: *Although the spend for most projects is reflected in a single year, the reality is that their planning and execution usually unfolds over a period of two to three years. This means that at any one time, projects are under development for many years. As delays are incurred on one project, others may be ready for execution, allowing field operations to proceed at a steady rate on high-value work.*

The updated capital spend for 2020 for the UGL rate zones is $546.4 million. This compares to the previously filed Union Rate Zones Asset Management Plan capital of $593.7 million. The decrease of approximately $47.3 million is driven mainly by the deferral of the Sarnia Industrial System Reinforcement project. This reduction is partially offset by the increase in Integrity work and the Kingsville project cost deferred from 2019.

Other changes of note in the budget are the addition of the Kirkwall-Hamilton NPS 48 project to reinforce the Dawn Parkway system in 2021. This project, with a budget of $4.6 million in 2020, was not identified at the time of AMP creation due to timing of the Dawn-Parkway Open season. The Waubuno project was deferred from 2021 to 2022, resulting in a decrease of $3.2 million in 2020. Both projects are ICM-eligible projects.

As has been noted in the past, EGI has a robust Integrity Management Program to be compliant with the requirements of *CSA Z662*. Through various integrity management processes, threats are identified and risks are evaluated, treated, and resolved to ensure the ongoing safety and reliability of the natural gas transmission and distribution system.

Two pipeline segments, a section of the Dawn Parkway system and two pipelines that traverse under the Detroit River, have been identified through the Integrity Management Program. At this time, the Integrity Management team is working with the Asset Class Managers to understand the asset condition, explore the assessment options and potential risk mitigation strategies**.** If capital and O&M investment is required in 2020, EGI will look for opportunities to prioritize this work.

[8] *As noted, the Sarnia Industrial Line project was previously identified as a single large project in the AMP. Three separate projects have since been identified to replace the original project. With the deferral, the total capital in 2020 for Sarnia Industrial Line system projects is $1.2M. The original 2020 budget amount was $60.4M, resulting in a decrease of $59.2M in the 2020 budget.*

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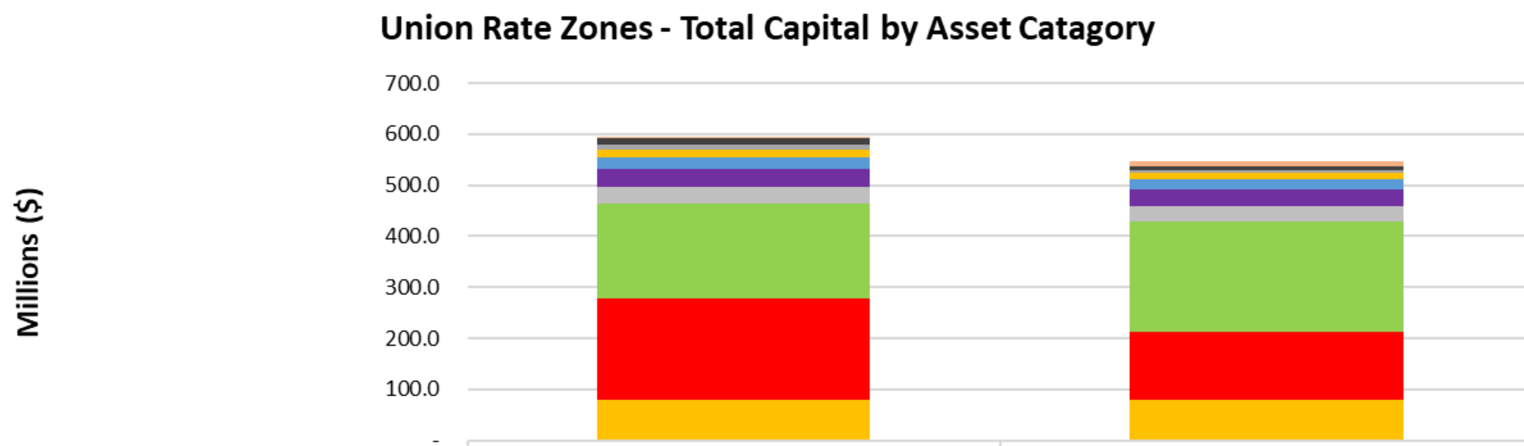
Figure 2.2-1 shows the comparison between the 2020 AMP budget figures and the proposed 2020 portfolio.



	2020 AMP	Proposed 2020
Transmission Pipe & Underground Storage	2.1	8.6
Fleet & Equipment	12.0	8.9
Compression & Dehydration	9.0	5.5
REWS	15.0	11.6
Distribution Stations	24.3	19.2
Utilization	34.9	33.6
TIS	31.3	31.0
Distribution Pipe	186.8	215.4
LNG	-	-
Growth	198.3	134.1
Overheads	80.0	78.4

Figure 2.2-1: Union Rate Zones 2020 AMP Budget and Proposed 2020 Portfolio Comparison

Table 2.2-2 shows the list of Potential ICM projects for the Union Rate Zones portfolio.

Table 2.2-2: Union Rate Zones ICM-eligible Projects

ASSET CLASS	INVESTMENT CATEGORY	PROJECT NAME	IN-SERVICE YEAR
Distribution Growth	System Service	Stratford Reinforcement[9]	2019
Distribution Growth	System Service	Owen Sound Reinforcement	2020
Distribution Growth	System Service	Kingsville Transmission Reinforcement Project[10]	2019
System Growth	System Service	2021 Sarnia Industrial Line Reinforcement Project [11] *(revised)*	2021
System Growth	System Service	Sarnia Expansion Project *(revised)*	2022
System Growth	System Service	2023 Sarnia Industrial Line Reinforcement Project *(revised)*	2023
Pipelines	System Renewal	Windsor Line	2020
Distribution Growth	System Service	Dunnville Line Reinforcement	2021
Distribution Growth	System Renewal	Waubuno Pool Project	2022
Pipelines	System Service	Byron Transmission Station Reinforcement	2021
Distribution Growth	System Service	Hamilton Gate	2022
Distribution Growth	System Service	Parry Sound Reinforcement	2023
Distribution Growth	System Service	Sudbury Compression Station	2023
Distribution Growth	System Renewal	Obsolete RB211-24A C Plant	2023
System Growth	System Service	NPS 48 Kirkwall to Hamilton *(new)*	2021
Compression and Dehydration	System Renewal	London Lines	2021

[9] *Stratford Reinforcement project approved for partial ICM funding in 2019 rate application.*
[10] *Kingsville Transmission Reinforcement project approved for ICM funding in 2019 rate application.*
[11] *Previously-identified Sarnia Industrial System ICM-eligible project replaced by three separate projects.*
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Table 2.2-3 shows the forecast costs for the potential ICM projects in the Union Rate Zones portfolio.

Table 2.2-3: Union Rate Zones ICM-eligible Projects: Forecast Costs

PROJECT NAME	2019 F	2020	2021	2022	2023	2024
2021Sarnia Industrial Line Reinforcement	507,820	1,034,457	26,450,000	1,076,000		
Sarnia Expansion Project		202,800	13,567,000	50,093,000	1,137,000	
2023 Sarnia Industrial Line Reinforcement	633,202			2,247,703	65,930,000	3,259,000
Owen Sound	280,192	55,767,755	1,921,000			
Kirkwall Hamilton *(new)*	1,581,443	4,549,365	172,793,000	5,024,000		
Byron		404,000	15,100,000			
Waubuno			817,000	18,746,000	1,430,000	
Parry Sound					15,000,000	
Dunnville			11,000,000			
Stratford	22,682,040	1,064,768				
Hamilton			7,000,000	20,000,000		
Sudbury Compression			3,700,000	12,900,000	33,600,000	1,400,000
Obsolete RB211				19,300,000	82,900,000	48,700,000
Kingsville	85,764,846	15,978,289				
Windsor	2,163,415	77,875,570	12,520,000			
London		4,000,000	107,000,000	3,000,000		
Total ICM-eligible Projects	113,612,958	160,877,004	371,868,000	132,386,703	199,997,000	53,359,000

Business cases for each of the emerging projects and other noted changes can be found in **Appendix D: List of Union Rate Zones Project Descriptions**.

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3 Appendix

3.1 APPENDIX A: EGD RATE ZONE ASSET MANAGEMENT PLAN 2019 - 2028

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Asset Management Plan 2019 - 2028

November 22, 2018

Report

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

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1 Executive Summary

1.1 DOCUMENT PURPOSE

The purpose of this Asset Management Plan is to outline:

- Policy and strategies for achieving effective asset management for all assets within Enbridge Gas Distribution's (EGD) regulated operations
- Process and governance for asset management
- Asset class objectives and life cycle management policies
- Asset inventory, condition methodology, condition findings, risks, opportunities, and strategies
- Optimized 10-year capital expenditures required to manage assets from 2019-2028

This Asset Management Plan aligns with ISO5500X, the International Standard for Asset Management and is intended to meet the Ontario Energy Board's (OEB) expectations as set out in the *Handbook for Utility Rate Applications* and the *Filing Requirements for Natural Gas Rate Applications.*

1.2 STRUCTURE OF THE ASSET MANAGEMENT PLAN

Figure 1.2-1 is an illustration of EGD's Asset Management Plan structure.

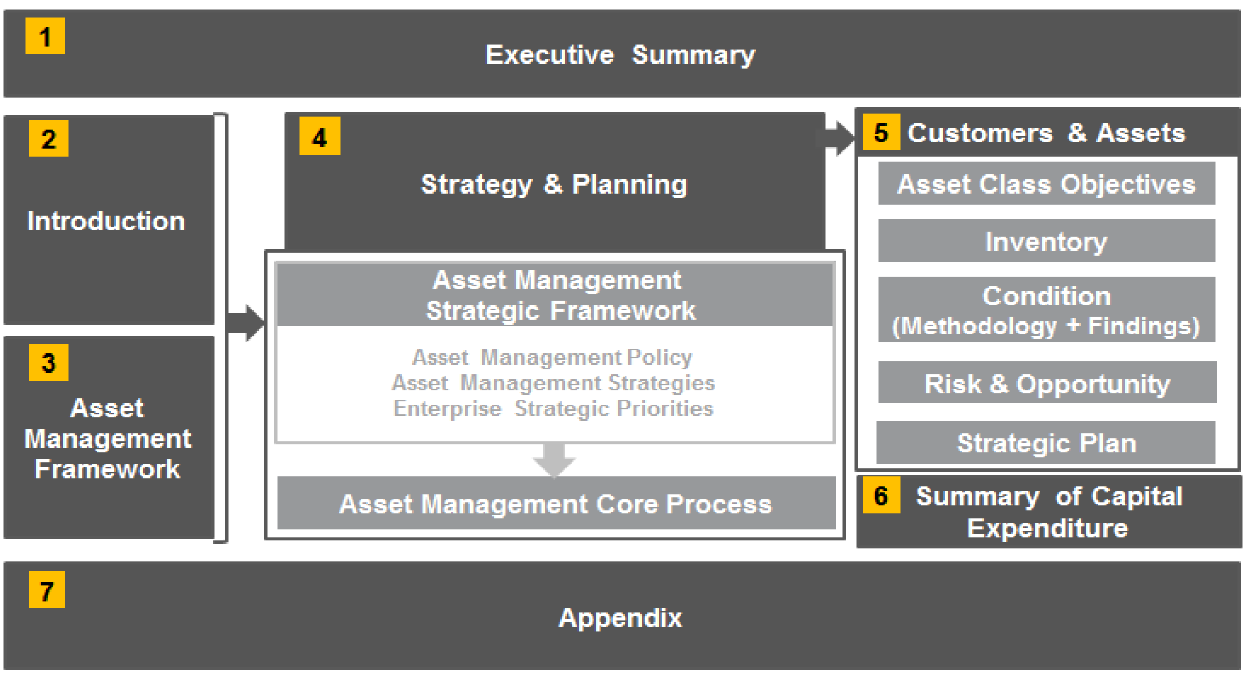


Figure 1.2-1: EGD's Asset Management Plan Structure

Introduction (Section 2) and Asset Management Framework (Section 3): This plan starts with an introduction of the company. It also highlights EGD's stakeholder commitment, improvements from previous EGD Asset Management Plans, the change management strategy, the document structure, and a summary of EGD's alignment to ISO5500X.

Strategy and Planning (Section 4): The Strategy and Planning section details the alignment of asset management at EGD with Enbridge's Enterprise Strategic Priorities and includes EGD's Asset Management Policy, Asset Management Strategies, and the Asset Management Core Process.

Customers and Assets (Section 5): The Customers and Assets section details the following for each asset class:

- Asset class objectives and life cycle policies
- EGD's customers and customer growth projections
- Asset inventory
- Asset condition and life cycle strategies for managing assets
- Strategic plans to meet life cycle strategies

Summary of Capital Expenditure (Section 6): This section summarizes the 10-year capital expenditure plan for EGD, outlines the optimization process, and highlights key assumptions used for Sections 5 and 6.

Appendix (Section 7): The Appendix presents supporting information for the Asset Management Plan.

1.3 OPERATIONAL FOCUS

Enbridge exists to fuel people's quality of life with a long-term vision to be the leading energy delivery company in North America. The Enbridge Enterprise Strategic Priorities (outlined in **Section 2.2.4**) are defined to enable the enterprise to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities and contribute to Enbridge's success. They support the company's purpose of fueling people's quality of life, maintaining the foundation of the business, and positioning the company for the future.

EGD's core goals are employee and public safety, compliance, financial performance, operational reliability, environmental sustainability, and customer satisfaction. These goals play a key role during the evaluation of cost, risk, and performance of asset investment decisions. EGD is committed to managing assets through established governance, policy, and practices. Asset management provides a governing framework to understand risks and opportunities, develop business plans to address them, and optimize a long term plan that balances cost, risk, and performance. EGD will continue to evolve its maturity in Asset Management as measured against ISO5500X.

EGD will apply leading asset management practices to effectively manage the life cycle of assets. Optimal value will be delivered to customers and stakeholders through a sustainable investment plan that balances cost, risk, and performance. Asset Management at EGD and this Asset Management Plan are a direct demonstration of the company's obligation to its stakeholders, ensuring asset value is realized and optimal decisions are made.

1.4 ASSET MANAGEMENT IMPROVEMENTS

In 2013, EGD filed an Asset Management Plan with the OEB for the first time as part of its Custom IR filing *[EB-2012-0459]*. From 2014 to 2018, EGD made progress in advancing its asset management framework to facilitate and govern asset investment planning within the organization, and prepared an improved version of its Asset Management Plan. In 2018, EGD submitted the Asset Management Plan for 2018-2027 in response to interrogatories during the Mergers, Acquisitions, Amalgamations and Divestitures (MAADs) and Rate-Setting Mechanism Applications *[EB-2017-0306/EB-2017-0307]*. Specific improvements included:

- The inclusion of all OEB-regulated assets in the Asset Management Plan
- The development of a multidisciplinary, systematic approach to asset planning
- The use of condition assessment, risk evaluation, and optimization for asset planning
- The direct linkage of the capital budget to the Asset Management Plan
- The incorporation of third-party assessments on EGD's asset management process and planning

EGD continues to evolve its asset management practices, and as a result, this Asset Management Plan (2019-2028) includes the following changes from 2018-2027:

- **Alignment with Enbridge Inc.'s 2018 Enterprise Strategic Priorities**
  Enbridge Inc. published a revised Strategic Plan in 2018. The alignment of EGD's Asset Management Policy, Asset Management Strategies, and dimensions of risk have been adjusted accordingly, found in **Section 4.1.4**.

- **Consideration of Integrated Resource Planning (IRP)**
  In response to the OEB's direction *[EB-2015-0049]* to submit a plan to incorporate Demand Side Management (DSM) into infrastructure planning activities, EGD has documented its Transition Plan and summarized this in **Section 3.5**. Integrated Resource Planning (IRP) will continue to be monitored as part of EGD's Asset Management Plan to ensure advancements made in the data collection and resultant strategies are acknowledged and incorporated during asset investment planning.

- **Evolution of asset condition and strategies**
  The structure of Customers & Assets (**Section 5**) has been updated. Inventory, condition, risk/opportunity and strategies have been updated to reflect the current understanding of assets. Specific project and program information is provided in the Appendix to support each asset class's strategic plans. The key changes are:
  - The inclusion of EGD's Business Development's lower-carbon strategies, such as Renewable Natural Gas (RNG), DSM, Geothermal, and Power-to-Gas, with no capital requirements included in this Asset Management Plan at this time (with the exception of Hydrogen Blending for Power-to-Gas). These initiatives are under various stages of regulatory review, and could be incorporated into future iterations of the Asset Management Plan.
  - Updates to the strategy on Storage Renewal for the Storage asset class to ensure comprehensive assessment of all solution options.
  - Updates to the strategy for distribution steel mains of the Pipe asset class to reflect current condition and risk information.

- **Exclusion of Projects Under Development**
  Projects where solution scopes are still under development are not currently included in EGD's 10-year portfolio of spend. These developing projects (six in total) are identified in **Section 6.4**, summing to a total of up to $470M and will be incorporated once solution timing and scopes are confirmed.

Moving forward, with the recent decision to amalgamate the two natural gas utilities in Ontario, EGD and Union Gas Limited (UGL) will work towards consolidating its Asset Management framework and plans.

1.5 CUSTOMERS AND ASSETS

EGD delivers safe and reliable natural gas to over 2.1 million customers, forecasted to grow over the 10-year period of this Asset Management Plan. These customers include residential, commercial, apartment buildings, and industrial customers.

EGD's franchise area is divided into eight administrative areas. Area 10 covers Toronto, Areas 20, 30, 40, and 50 cover the remainder of the Greater Toronto Area (GTA), Area 60 covers Ottawa and the surrounding region. Area 70 covers Gas Storage operations in southwestern Ontario and Area 80 covers the Niagara region.

Figure 1.5-1 and **Figure 1.5-2** profiles EGD's existing customer base by type and area.

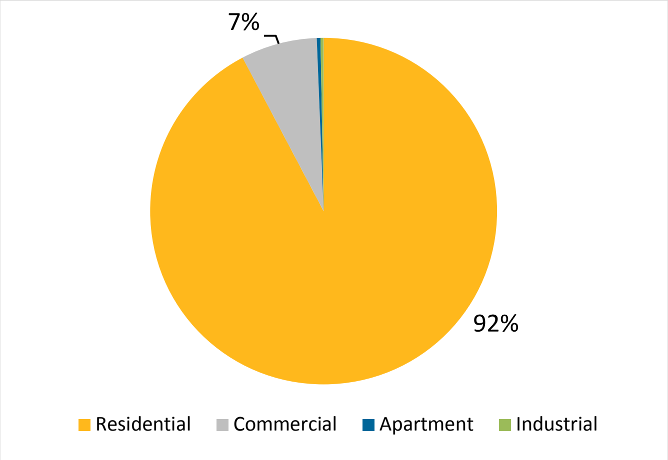


Figure 1.5-1: Customer Breakdown by Type

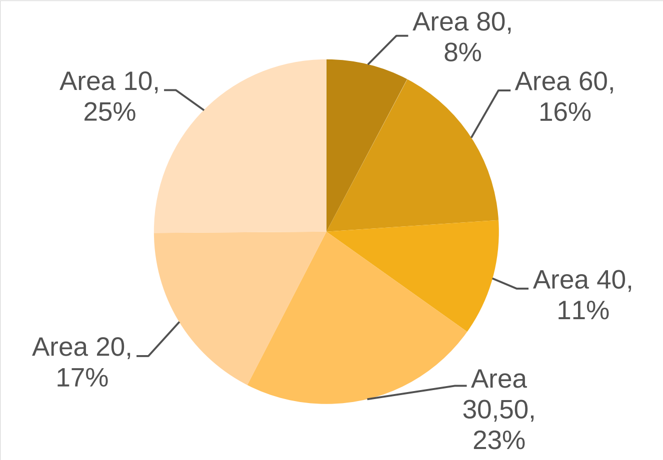


Figure 1.5-2: Customer Breakdown by Area

1.6 ASSET CLASSES

The Asset Management Program considers all OEB-regulated assets, which have been grouped into nine classes: *Pipe, Stations, Storage, Customer Assets, Fleet & Equipment, Technology & Information Services (TIS), Real Estate & Workplace Services (REWS), Customer Growth*, and *Business Development*.

Investment decisions are categorized and managed on an asset class basis, where each asset class has a unique set of objectives and life cycle management policies that guide decision-making. With an understanding of the asset inventory and the evaluation of condition and risk, resultant strategies are outlined. Refer to **Section 5**.

1.7 ASSET MANAGEMENT

Asset management at EGD is based on Deloitte's Value-Based Asset Management Model (**Figure 1.7-1**), which provides the framework for EGD's Asset Management Program. This model integrates all asset management activities into a four-step management system of Plan-Do-Check-Act while supporting the implementation of the following asset management strategies:

- Align roles and structure to support asset management
- Produce and evaluate asset information and condition
- Implement life cycle management for assets
- Optimize portfolio based on asset management principles
- Utilize asset management tools that evolve to meet business needs
- Forecast long term asset investment plan

Asset management strategies and objectives are aligned with EGD's Asset Management Policy and are achieved through the Asset Management Core Process (**Section 4.2**) and Asset Class Objectives (**Section 5**).

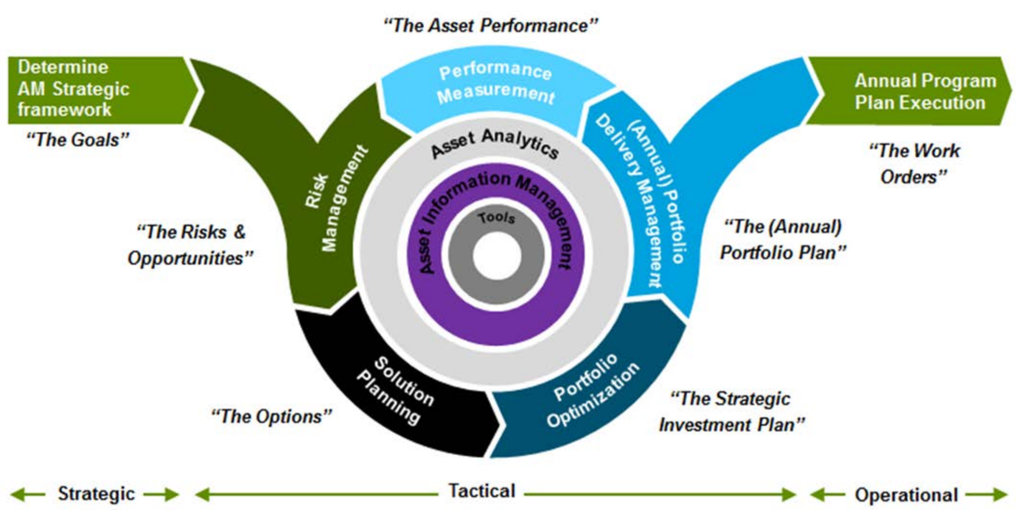


Figure 1.7-1: Value-Based Asset Management Model

Each chevron of the Value-Based Asset Management Model represents a key component in the asset management process:

- Determining EGD's Strategic Framework
- Identifying risks, opportunities, and their resultant investment options
- Outlining how optimized decisions are made for the strategic investment plan and annual portfolio plan (i.e., the Asset Management Plan)
- Explaining how asset management performance is measured
- Outlining the tools, data, and analytics that support these activities

1.8 CONDITION AND STRATEGY OVERVIEW

1.8.1 Customer Growth Strategy Overview

CONDITION	RISK / OPPORTUNITY	STRATEGY
Between 2007 and 2017, EGD's customer growth was approximately 35,000 customers per year. In 2018, EGD expects to add approximately 31,700 new customers. Between 2018 and 2028, EGD's customer growth is forecasted to be approximately 30,100 customers per year on average.	EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers (*EBO 188*), where feasibility is quantified by determining the value of a project's revenues against its costs (the Profitability Index or PI).	The strategy for the Customer Growth asset class is to ensure that required infrastructure is installed to enable the addition of all forecasted customers that are feasible under *EBO 188* guidelines. EGD continues to monitor and update the customer additions forecast through the annual Long Range Planning process.

1.8.2 Pipe Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Integrity Mains	40	Integrity Management Program (IMP) mains are generally in good condition. All in-line inspection (ILI) detectable features requiring immediate mitigation and scheduled inspections are addressed within the timeline outlined in the Transmission Integrity Management Program (TIMP). Non-immediate corrosion features will be projected for future scheduled inspection or continue to be monitored through the Pipeline Integrity Management Program.	Risks identified for integrity mains: *Safety Risk:* Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *Customer Satisfaction (CSAT) Risk*: Greenhouse Gas (GHG) emissions, environmental impact, extensive customer outage, and reputational damages.	The maintenance strategy for integrity mains includes: • 7-year internal inspection • Vital Main Damage Prevention Program • Annual Leak Survey (High Consequence Areas leak surveyed semi-annually) • Cathodic Protection (CP) monitoring	EGD's replacement/renewal strategy for integrity mains is through: • **Pipeline Integrity Management Program**: Proactive program mandating ILIs on integrity main assets at seven-year inspection intervals. An Engineering Assessment using a probability approach is completed to rank pipeline anomalies, set re-inspection frequency, and repair pipeline indications as deemed necessary. Immediate or scheduled digs, repairs, and replacements are initiated as required. • **Emergency Replacement Program**: Main repairs or reactive replacements to address leaks and condition issues as identified. The approach depends on the extent of the main's poor condition. Localized poor condition is managed through pipeline repairs. Broader condition issues are managed through more extensive replacement.
Distribution Steel Mains	43	Steel mains are generally in good condition, with the exception of those found to be with inadequate CP protection or other condition issues such as reduced depth of cover due to municipal road work or specific pipeline features (e.g., blow-off valve assemblies). The population of steel mains installed in the1970s and prior (i.e., vintage steel) has been found to have varying degrees of corrosion associated with declining cathodic protection and poor coating, driving the steady increase of forecasted leak rates.	Risks identified for distribution steel mains: *Safety Risk*: Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for distribution steel mains includes: • A leak survey conducted every five years (annually for vital mains) • CP monitoring	EGD's replacement/renewal strategies to manage distribution steel mains is through: • **Corrosion Prevention Program**: Annual anode replacement program to ensure the steel main system is receiving sufficient cathodic protection. • **Relocation Program**: Relocation of pipe assets to reduce or mitigate the impact of third-party work on the safe operation of the distribution system (which can involve multiple asset subclasses). • **Emergency Replacement Program**: Main repairs or reactive replacements to address leaks and condition issues as identified. The approach depends on the extent of the main's poor condition. Localized poor condition is managed through pipeline repairs. Broader condition issues are managed through more extensive replacement. • **Major Pipeline Replacement Projects**: Material projects to manage risks of large diameter pipelines, to reduce or prevent risk from approaching the intolerable risk region. • **Distribution Steel Mains Replacement Program**: Steel main replacement program forecasted based on leak projections. Condition information is used to identify and prioritize projects. • Continuous improvement related to the development of proactive strategies to renew aging assets before reaching end-of-life.

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Distribution Plastic Mains	**Plastic Mains (Pre-1977)**	43	Pre-1985 plastic mains are found to be in good condition; however, the failure curve predicts a rapid degradation over a very short period of time.	Risks identified for distribution plastic mains: *Safety Risk:* Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for distribution plastic mains requires a leak survey to be conducted every five years.	EGD's replacement/renewal strategies to manage plastic mains is through: • **Emergency Replacement Program**: Main repairs or reactive replacements to address leaks and condition issues as identified. The approach depends on the extent of the main's poor condition. Localized poor condition is managed through pipeline repairs. Broader condition issues are managed through more extensive replacement. • **Vintage Plastic Main Replacement Program**: Proactive replacement program to renew aging assets (pre-1985) before reaching end-of-life. • **Relocation Program**: Relocation of pipe assets to reduce or mitigate the impact of third-party work on the safe operation of the distribution system (which can involve multiple asset subclasses). • Perform an Integrity Assessment on 1977-1985 plastic mains to understand material characteristics and failures of the asset population and determine the asset strategy.
	Plastic Mains (1977-1985)	36				
	Plastic Mains (Post-1985)	17	Post-1985 plastic mains are found to be in good condition. The materials and manufacturing processes support the longevity of this asset.			
Distribution Services	**Steel Services**	40	Steel services are generally found to be in good condition, with the exception of those services with inadequate CP protection, where the steel services are connected to a compression style service tee, or attached to plastic mains.	Risks identified for distribution services: *Safety Risk*: Gas leaks with migration through underground infrastructure into buildings, resulting in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for steel services includes: • A leak survey is conducted every five years (semi-annually for unprotected services). • CP monitoring	EGD's replacement/renewal strategies for distribution services on steel, plastic, and copper services is through: • **Service Relay Program**: Program to address leaks and condition issues as identified. Leaks on steel services are managed through temporary repairs and followed up with service relays as a permanent solution. • **Vintage Steel Replacement Program**: Proactive replacement of steel services to be completed with the Steel Mains Replacement projects. • **Vintage Plastic Replacement Program**: Proactive replacement of plastic services to be completed with the Plastic Mains Replacement projects. • **Copper Service Replacement Program**: Proactive strategy to replace remaining copper services as part of the Service Relay Program.
	Plastic Services	20	Plastic services are generally found to be in good condition.		The maintenance strategy for plastic services includes: • A leak survey is conducted every five years for pre-1985 services. • A leak survey conducted every 10 years for post-1985 services.	
	Copper Services	49	Copper services in general are failing at a rate higher than any other service type due to erosion corrosion and degradation associated with dissimilar metals at the fittings.		The maintenance strategy for copper services requires a leak survey to be conducted annually.	
Distribution Risers	**Steel Risers**	45	Steel risers are generally found to be in good condition.	Risks identified for risers: *Safety Risk*: Risk due to gas leaks with migration through underground infrastructures into buildings, resulting in gas accumulation and explosions. *Financial Risk*: Risk due to total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: Risk associated with GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for risers includes: • Leak Survey program (frequency dependent on service material). • CP monitoring for steel risers	EGD has a reactive and proactive replacement/renewal strategy for distribution risers: • **Reactive Replacement Program**: Service relay program to replace leaking or poor condition steel, plastic-in-conduit, anodeless, and copper risers. • **Vintage Steel Main Replacement Program**: Proactive replacement of steel risers to be completed with the Steel Mains Replacement projects. • **AMP Fitting Replacement Program**: Targeted proactive replacement of high risk AMP fittings.
	Plastic-in-Conduit Risers	28	Plastic-in-conduit risers are generally found to be in good condition.			
	Anodeless Risers	13	Anodeless risers are generally found to be in good condition.			

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
	Copper Risers	39	Copper risers in general are failing at a rate higher than any other service due to erosion corrosion and degradation at the fittings. While the population may be in good condition, failures increase sharply when the riser approaches 50 years old.			
Valves		26	Valves are generally found to be in good condition.	Risks identified for valves: *Safety Risk*: Risk due to prolonged duration of leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and explosion. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental impact, customer outages, and reputational damages.	The maintenance strategy for valves includes: • A leak survey is conducted through the Distribution Main/Service Survey Program. • Annual Valve Inspection Program	EGD has a reactive replacement/renewal strategy for valves: **Emergency Replacement Program**: Replacement of the asset when a valve is leaking, non-functioning, or inaccessible.
System Reinforcements		N/A	Load Gathering and Simulation, Annual Forecasting, and Long Range System Planning are completed and areas have been identified requiring reinforcement.	Ensure security of gas supply to existing customers and support forecasted customer growth using the guidelines of *EBO 188*.	N/A	EGD's replacement/renewal strategy for system reinforcements is through the **Reinforcement Program**, which mandates the reinforcement of pipeline networks identified by the distribution System Long Range Plan (which can involve multiple asset subclasses).

1.8.3 Stations Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Gate Stations	16	Gate and feeder stations are assessed using the same condition criteria. At certain sites, the telemetry, pressure control, and heating system components were found to have the following deficiencies: obsolescence, performance issues, and non-standard configurations.	The risks at gate and feeder stations are: *Safety Risk*: Due to impact on surrounding population in the event of loss of containment *Financial Risk*: Commodity loss, repair costs, and regulatory penalties *CSAT Risk*: GHG emissions, loss of service to customers, and company reputational impact	The maintenance strategy for gate stations is scheduled as described in the Regulation and Measurement (R&M) Manual: • Weekly gate station inspections • 1 operational inspection annually • 1 maintenance inspection annually	EGD has the following strategies for gate and feeder stations: • **Gate & Feeder Station Replacement Program**: Proactive replacement of component groups with the highest probability of failure, non-compliant assets, and the realization of opportunities for multiple component group replacements per station location as required. • **Telemetry Program**: Proactive upgrades of small-scale, obsolete telemetry components. These upgrades will be out of scope for larger-scale station replacement projects. • **Compliance Remediation Program**: Proactive focus on code compliance issues found through detailed site surveys. These will be addressed through a grouped program approach, outside the scope of larger-scale replacement projects.
Feeder Stations	15			The maintenance strategy for feeder stations is scheduled as described in the R&M Manual: • Monthly feeder station inspections • 1 operational inspection annually • 1 maintenance inspection annually	

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
District Stations	18	Field condition survey assessments identified the existence of boot style regulators, below-ground installations, non-conforming configurations, and vintage/obsolete components, contributing to a higher potential of failures and operational issues.	The risks at district stations are: *Safety Risk*: Employee safety, threat to over pressuring the downstream network *Financial Risk*: Repair and high maintenance costs *CSAT Risk*: Loss of service to customers, reputational impact	The maintenance strategy for district stations is scheduled as described in the R&M Manual: • 1 operational inspection annually • 1 maintenance inspection every five years	EGD has the following strategy for district stations: **District Station Replacement Program:** Proactive replacement program that targets stations based on obsolescence, condition, and age. The program targets approximately 20 stations per year, aligned with historical replacement rates that maintain the average age of the population.
Header Stations	18	Field condition survey assessments of header and sales station sites have found non-conforming configurations and installation locations deemed to be potential hazards to the safe operation of the station site.	The risks at header and sales stations are: *Safety Risk*: Public impact, threat to over-pressuring customer piping *Financial Risk*: Repair and high maintenance costs, customer supply impact *CSAT Risk*: Loss of service to customers, reputational impact	The maintenance strategy for header stations is scheduled as described in the R&M Manual: • 1 operational inspection every five years	EGD has the following strategy for header stations: **Header Station Replacement Program:** Proactive replacement program that targets stations based on obsolescence, condition, and age. The program will target approximately 50 stations per year, which is aligned with historical replacement rates that maintain the average age of the population. Header stations continue to be monitored through the inspection program and condition will be assessed as problems are detected.
Sales Stations	17			The maintenance strategy for sales stations is scheduled as described in the R&M Manual: • 1 operational inspection every five years, or one operational inspection annually (depending on classification)	EGD has the following strategy for sales stations: **Sales Station Replacement Program:** Proactive replacement program that targets stations based on obsolescence, condition, and age. The program will target approximately 100 stations per year, slightly higher than historical values to maintain the current average age of the population. Sales stations continue to be monitored through the inspection program and condition will be assessed as problems are detected.

1.8.4 Storage Condition and Strategy Overview

1.8.4.1 Compressor Stations

ASSET SUBCLASS			AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Gas Compressors	**Corunna (SCOR)**	**Foundations**	36	The Corunna compressor has reduced technical support from the manufacturer. Compressor foundations are deteriorating, causing bearing failures and bent crankshafts. Foundations for K705 and K706 were recently replaced. Except for K701/2/3, engine and compressor assemblies are in fair condition. K701/2/3 units are experiencing very poor reliability. Gas aftercoolers (GAC) and Jacket Water Coolers (JWC) have undergone fan drive retrofits. However, tube bundles are original for all units except for K704 GAC. Mode valves, which are manifolded to the header system, are all original and unable to provide a sufficient seal when the valve is in	Age and operating hour issues are key risk influencers. Compressor component failures are key threats that pose the following risks: *Safety Risk*: • Risk of crankshaft and engine frame failure can result in significant collateral damage to units with a direct influence on safety risk to employees. • Valves which do not seal create a process safety risk during an Emergency Shutdown (ESD) event and to personnel. • Crowland unit valve configuration is a process safety concern because valves are manually actuated with no loading valve. Manually actuated valves do not accommodate automatic ESD strategies	The maintenance strategy to maintain compressor stations is to: • Conduct preventative maintenance inspections prescribed by the manufacturer • Continue adhering to the current Valve Maintenance Program	EGD's replacement/renewal strategy to maintain the Corunna compressor station is to: • Replace deteriorating compressor foundation blocks. • Evaluate options for replacement of K701/2/3 compressor units and perform a Front-end Engineering Design (FEED) study of the selected replacement option. • Continue to overhaul compressor and engine assemblies. • Mitigate obsolescence of sub-systems and auxiliary systems. • Proactively replace obsolete systems/devices and upgrade with new technology. • Upgrade units to minimize air emissions.
		Crankshaft Assemblies	45				
		Engine Assemblies	45				

ASSET SUBCLASS			AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
		Compressor Assemblies	43	the closed position. Mode valve seal quality is considered to be in poor condition.	*Financial Risk*: Reciprocating compressor failures (unplanned outages) result in unexpected repair costs (both materials and labour) and frequently involve collateral damage. *CSAT Risk*: Unplanned unit failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.		• Proactively replace JWCs. • Continue to enhance understanding of asset health and life cycle cost for compression facilities. • Gas compressor upgrades are expected to comply with anticipated restrictions on methane releases to atmosphere. • Replace bypass valve. Reliability issues related to K701/2/3 are expected to be sufficiently large to warrant their retirement. A comprehensive assessment of solution options is currently underway.
		Gas Aftercoolers (GAC)	40				
		Heating & Cooling System	45				
		Valve Systems	45				
	Sombra (SSOM)	**Foundations**	17	SSOM compression is 20 years old and considered to be in good condition.			EGD's replacement/renewal strategy to maintain the SSOM compressor station is to: • Perform minor compressor and engine assembly overhauls per Original Equipment Manufacturer (OEM) recommendations. • Continue to enhance understanding of asset health and life cycle cost for compression facilities. • Replace bypass valve.
		Crankshaft Assemblies					
		Engine Assemblies					
		Compressor Assemblies					
		Gas Aftercoolers					
		Heating & Cooling System					
		Valve Systems					
	Chatham D (SCHT)	**Foundations**	20	Chatham D compression is 20 years old and considered to be in good condition.			EGD's replacement/renewal strategy to maintain the Chatham D compressor station is to: • Perform minor compressor and engine assembly overhauls per OEM recommendations. • Continue to enhance understanding of asset health and life cycle cost for compression facilities.
		Crankshaft Assemblies					
		Engine Assemblies					
		Compressor Assemblies					
		Gas Aftercoolers					
		Heating & Cooling System					
		Valve Systems					
	Crowland (SCRW)	**Foundations**	47	Crowland is considered to be in fair condition. Crowland is almost 50 years and is an older vintage compressor. It is anticipated that the			EGD's replacement/renewal strategy to maintain the Crowland compressor station is to: • Replace/modify compression to optimize
		Crankshaft Assemblies					

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
	Engine Assemblies **Compressor Assemblies** **Gas Aftercoolers** **Heating & Cooling System** **Valve Systems**		valve systems are likely to exhibit condition concerns. The compressor unit typically operates for approximately 650 hours per year. Crowland has been identified as requiring additional noise mitigation measures.			operational reliability, process safety, and personnel safety, and ensure long term sustainability. • Implement noise mitigation measures to be in compliance with environmental regulations. • Continue to enhance understanding of asset health and life cycle cost for compression facilities.
Yard Process Pipe	**Corunna (SCOR)**	45	Yard process pipe is generally thought to be in good physical condition (as it relates to corrosion). Corunna threats to process safety include: • Material of unknown notch toughness • Piping vibration • Thermal growth • Legacy pipe designs	Yard process piping systems provide support to gas compressors. A significant failure can affect multiple gas compressor units. The risks associated with not maintaining yard process piping are: *Safety Risk*: A loss of containment causing leaks and creating flammable mixtures has the potential to injure workers. *Financial Risk*: Failures can cause moderate damage to company facilities, requiring repair costs. *CSAT Risk*: Failures can result in loss of Storage deliverability, therefore reducing operational reliability. Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost.	The maintenance strategy to maintain yard process pipe assets is to: • Ensure external coatings are re-applied regularly to prevent external corrosion of above grade pipe. • Regularly inspect performance of cathodic protection systems. • Inspect pipe condition (i.e., Facilities Integrity Management Program (FIMP)) for evidence of any threat to pipe condition.	EGD's replacement/renewal replacement/renewal strategy for yard process pipe assets is to: • Perform an assessment of the cross-flow header system to understand the extent and impact of the experienced vibration. The mitigation option being investigated is to replace the above-grade cross-flow header system and process piping at Corunna. A Front-end Engineering Design (FEED) study is currently underway to further evaluate design options. • Replace used pool inventory meters and associated yard piping at Corunna with modern buried pipe. • Continue FIMP and Hazard and Operability Study (HAZOP) assessments across all compressor stations.
	Sombra (SSOM)	19				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	42				
Yard Auxiliary Systems	**Corunna (SCOR)**	38	Yard auxiliary systems are generally thought to be in good physical condition (as it relates to corrosion). Corunna factors influencing condition include piping vibration and legacy pipe designs.	Yard auxiliary systems provide support to gas compressors - a significant failure can affect multiple gas compressor units. The risks associated with not maintaining yard auxiliary systems are: *Safety Risk*: Loss of containment causing leaks and creating flammable mixtures has the potential to injure workers. *Financial Risk*: Failures can cause moderate damages to company facilities, requiring repair costs. *CSAT Risk*: Failures can result in loss of Storage deliverability, therefore reduced operational reliability. Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost.	The maintenance strategy to maintain yard auxiliary systems is to: • Ensure external coatings are re-applied regularly to prevent external corrosion of above-grade pipe. • Regularly inspect performance of cathodic protection systems. • Inspect pipe condition (i.e., FIMP) for evidence of any threat to pipe condition.	EGD's replacement/renewal replacement/renewal strategy for yard auxiliary assets is to: • Proactively replace obsolete yard auxiliary system components. • Overhaul the start air compressors at Corunna. • Upgrade the existing air compressor at Chatham D. • Upgrade and expand the existing on-site firewater protection system. • Design and install a knock-out drum and metering system for the existing maintenance flare.
	Sombra (SSOM)	16				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	25				
Yard Valves & Actuators	**Corunna (SCOR)**	33	Valve actuators are generally repairable until parts are no longer available.	Process safety risks need to be mitigated due to poor seal quality. Failures due to poor seal quality	The maintenance strategy to maintain yard valves & actuators is to:	EGD's replacement/renewal strategy for yard valves & actuators is to:

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
	Sombra (SSOM)	16	Valve seal quality diminishes slightly with each actuation and is influenced by age, cycling frequency, and amount of abrasive debris in the gas stream. Many valves are believed to have poor seal quality and represent a threat to containment during an emergency event.	pose financial and customer satisfaction risks. *Safety Risk*: Inadequate gas containment by valves caused by actuator or seal failure during an emergency situation has the potential to injure workers and the public. *Financial Risk*: Failure of yard valves & actuators to operate as designed during an Emergency Shutdown (ESD) has the potential to exacerbate damage to non-company infrastructure, and commodity loss. *CSAT Risk*: Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.	• Assess actuator condition, based on frequency of repairs. • Assess valve condition based on Subject Matter Advisors (SMA) input and direct measurement. Future inspection methodologies are being evaluated. • Complete the valve maintenance program.	• Upgrade the valve actuators at SSOM to address obsolescence. • Overhaul the valve actuators at Chatham D to address poor condition. • Replace yard valves at Corunna to address poor seal quality.
	Chatham D (SCHT)	20				
	Crowland (SCRW)	30				
Control & Communicatio n	**Corunna (SCOR)**	20	The physical condition of these assets is good. A summary of the key condition conclusions is as follows: • Obsolete equipment is approaching end-of-life (radios, field instruments/controllers, and Programmable Logic Controllers (PLC)) • A growing number of systems at SSOM, Chatham D, and meter stations require access to the telemetry system, exceeding the bandwidth provided by existing infrastructure. • Inadequate climate control: o Chatham D: New devices have been installed on an external wall to accommodate increasing instrumentation demands. o SSOM: The current Local Area Network (LAN) facility consists of a panel located in the open and with minimal security. • UPS systems are experiencing battery degradation.	Failure of these assets primarily expose EGD to financial and customer satisfaction risks. Parts unavailability or delays can lead to longer downtime when a failure occurs.	The maintenance strategy for control & communication equipment is to monitor parts availability and introduce generational changes in product lines.	EGD's replacement/renewal strategy for control & communication equipment is to: • Upgrade and replace obsolete radio communication devices. • Install and upgrade the server, software, and hardware components of the primary operating interfaces (between the operator and the control of the assets) approaching end-of-life. • Maintain the prescribed replacement of industrial data centres. • Upgrade PLCs to maintain manufacturer supportability. • Expand and update the Chatham D control room with climate controls, Uninterruptible Power Supply (UPS) redundancy and security systems. • Install individual fibre optics links from Corunna to core facilities in the Storage system. • Develop training material, including simulated situations and expected scenarios. • Install industrial wireless service, obtain field equipment to securely access, and update operational records. • Upgrade the Supervisory Control and Data Acquisition (SCADA) system to ensure electronic control systems are configured, updated, and secured. • Upgrade radio frequency communication links between Tecumseh, Mid/South Kimball, Sombra, and Wilkesport compressor/meter stations. • Upgrade Instrumentation and Electrical (I&E) controls at SSOM and connect them to existing remote input/output devices. • Install a LAN room at SSOM with climate controls and security systems.
	Sombra (SSOM)	20				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	20				

<table>
<tr><th colspan="2">ASSET SUBCLASS</th><th>AVG. AGE (YR)</th><th>CONDITION</th><th>RISK / OPPORTUNITY</th><th>MAINTENANCE STRATEGY</th><th>REPLACEMENT/ RENEWAL STRATEGY</th></tr>
<tr><td rowspan="4">Electrical Devices</td><td>Corunna (SCOR)</td><td>21</td><td rowspan="4">The physical condition of these assets is good, with older systems being fair.
A summary of the key condition conclusions is as follows:
The existing transfer switch (used to control up to 600 VAC, three-phase circuits) which requires the entire plant be de-energized and de-pressurized to perform maintenance/repairs is approaching end-of-life.
Existing gas aftercoolers are On/Off type fan drives, which consumes more hydro power and requires more maintenance.
The inverter at Chatham D has been identified by SMAs as having poor reliability (frequent failures requiring repair) and is approaching end-of-life.
Older light poles have been identified to have corrosion, specifically at the base of the light pole, jeopardizing structural integrity.</td><td rowspan="4">Failure of these assets primarily expose EGD to financial and customer satisfaction risks. Parts unavailability or delays can lead to longer downtime when a failure occurs.</td><td rowspan="4">The maintenance strategy for electrical assets is to monitor parts availability and introduce generational changes in product lines.</td><td rowspan="4">EGD's replacement/renewal strategy for electrical assets is to:
Replace the existing transfer switch with a new unit employing a wrap-around bypass.
Replace existing On/Off cooling fan motor starters with variable frequency drives.
Replace light poles that are showing signs of corrosion.
Replace phase inverters experiencing reliability concerns.</td></tr>
<tr><td>Sombra (SSOM)</td><td>15</td></tr>
<tr><td>Chatham D (SCHT)</td><td>20</td></tr>
<tr><td>Crowland (SCRW)</td><td>34</td></tr>
<tr><td rowspan="4">Metering Systems</td><td>Corunna (SCOR)</td><td>22</td><td rowspan="4">Most metering systems located in compressor stations are 20 years old or less. Metering systems have a long life expectancy but can be vulnerable to obsolescence.
The Black Creek inventory management meter is obsolete and no longer supported by the manufacturer.</td><td rowspan="9">Failure of these assets primarily expose EGD to financial and customer satisfaction risks. Parts availability can lead to longer downtime when a failure occurs.
Not maintaining these assets poses the following risks:
Safety Risk: Loss of containment has the potential to injure workers and the public if asset condition is allowed to degrade, causing leaks and creating flammable mixtures.
Financial Risk: Key financial risk drivers are escalating cost of parts for obsolete equipment, potential for third party and company damages, commodity loss, and environmental cleanup.
CSAT Risk: Obsolete equipment can cause extended outage durations. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single failure within this grouping of assets can shut down an entire compressor station.</td><td rowspan="4">The maintenance strategy for metering systems is to monitor parts availability and introduce generational changes in product lines.</td><td rowspan="4">EGD's replacement/renewal strategy for metering systems is to:
Upgrade the obsolete and unsupported ultrasonic meters at SSOM with new units.
Continue to enhance the understanding of asset health and life cycle costs for the metering system, flow control valves, and dehydrators & incinerators.</td></tr>
<tr><td>Sombra (SSOM)</td><td>18</td></tr>
<tr><td>Chatham D (SCHT)</td><td>20</td></tr>
<tr><td>Crowland (SCRW)</td><td>N/A</td></tr>
<tr><td rowspan="4">Flow Control Systems</td><td>Corunna (SCOR)</td><td>19</td><td rowspan="4">Flow control systems located in compressor stations are 20 years old or less. Flow control systems have a long life expectancy but can be vulnerable to obsolescence.</td><td rowspan="4">The maintenance strategy for flow control systems is to monitor parts availability and introduce generational changes in product lines.</td><td rowspan="4">EGD's replacement/renewal strategy for flow control systems is to continue to enhance the understanding of asset health and life cycle costs for the metering system, flow control valves, and dehydrators & incinerators.</td></tr>
<tr><td>Sombra (SSOM)</td><td>14</td></tr>
<tr><td>Chatham D (SCHT)</td><td>20</td></tr>
<tr><td>Crowland (SCRW)</td><td>30</td></tr>
<tr><td>Dehydrators & Incinerators</td><td>Corunna (SCOR)</td><td>N/A</td><td>These assets are normally custom built, so they are minimally vulnerable to obsolescence.
The condition of these assets is characterized by internal corrosion and condition of re-boiler fire tube. Dehydrators and incinerators have a very long life expectancy.
Currently, all dehydrators and incinerators are fully automated, with the exception of the unit at Chatham D.</td><td>The maintenance strategy for dehydrators & incinerators is to:
Ensure external coatings are regularly re-applied to prevent external corrosion of vessels.
Continue to implement the pressure vessel and tank inspection program under FIMP.</td><td>EGD's replacement/renewal strategy for dehydrators & incinerators is to:
Upgrade the dehydrator and incinerator at Chatham D to a fully automated unit, allowing remote operator visibility and control.
Continue to enhance the understanding of asset health and life cycle costs of these assets.</td></tr>
</table>

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Filters, Separators & Tanks	**Corunna (SCOR)**	45	These assets are normally custom built, so they are not vulnerable to obsolescence. The condition of these assets is characterized by internal corrosion. Filters and separators have a very long life expectancy. Atmospheric tanks are generally constructed with much thinner walls (corrosion potential). Asset condition is being assessed via a new inspection program. Approximately half of these assets have been inspected. Most pressure vessels and tanks are in good condition. The condition of a small portion of inspected liquids tanks (such as Chatham D) is very poor. A consolidated condition report is in progress.	Not maintaining filters, separators, and tanks poses the following risks: *Safety Risk*: Loss of containment has the potential to injure workers and the public if asset condition is allowed to degrade, causing leaks and creating flammable mixtures. *Financial Risk*: Key financial risk drivers are escalating cost of parts for obsolete equipment, potential for third party and company damages, commodity loss, and environmental cleanup. *CSAT Risk*: Atmospheric tanks can suffer from wall/weld corrosion leading to an environmental spill. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.	The maintenance strategy for filters, separators, & tanks is to: • Ensure external coatings are regularly re-applied to prevent external corrosion. • Continue to implement the pressure vessel and tank inspection program under FIMP.	EGD's replacement/renewal strategy for filters, separators, & tanks is to: • Complete the development of the Pressure Vessel and Tanks Inspection Program. • Develop a more complete understanding of life cycle costs for filters, separators & tanks . • Develop forecasting tools to predict appropriate timing for filter, separators, & tank replacements. • Replace filter and separator vessel closures that pose a potential hazard to maintenance personnel. • Replace tanks and associated secondary containment identified to be in poor condition. • Replace atmospheric tanks with pressure vessels designed to connect with high-pressure, low-point drain systems. • Design and install platforms for worker safety when changing filter elements and working around separators.
	Sombra (SSOM)	17				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	47				
	Sombra (SSOM)	10				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	19				

1.8.4.2 Pipelines

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Pipelines	**Transmission**	41	In-line inspections for all pipelines are completed. No issues currently require remediation. Asset condition is considered good.	Not maintaining pipelines poses the following risks: *Safety Risk*: Loss of containment could have a major influence on public and employee safety. *Financial Risk*: Unexpected pipeline failures carry a large cost of replacement. *CSAT Risk*: Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost. The outage duration will depend on the magnitude of the failure.	The maintenance strategy for pipelines is to: • Ensure external coatings are re-applied regularly to prevent external corrosion of above-grade pipe. • Regularly inspect performance of cathodic protection systems. • Inspect pipe internal condition (i.e., TIMP) for evidence of any threat to pipe condition • Perform ILIs every seven years. • Track changes in asset condition over time using direct measurements.	EGD's replacement/renewal strategy for pipelines is to: • Continue to assess the condition of pipelines, perform regular ILIs and employ condition data to forecast the timing of proactive replacements. • Maintain adequate cathodic protection systems to protect the pipelines from corrosion. • Reactively replace well loop piping under strain due to buried pipe settlement discovered through reservoir maintenance work. • Install pressure-indicating transmitters at the pipeline entry point into compressor stations to validate the performance of the storage pipeline system.
	Pool	31				
	Gathering	38				
	Laterals	36	All laterals will be 100% inspected by 2019. Asset condition is considered good. During work activities involving the removal of lateral loops, it has been found that there is inadequate pipe support due to settlement of the soil surrounding laterals. The weight of the pipe is supported by the well loop which attaches to the lateral to the well.			
	Pipeline Valves	12	Most pipeline valves are line valves located at the end of every lateral. Many of these valves were replaced to accommodate ILIs. SMAs have indicated that many pipeline valves are known to have seal quality deterioration to such an extent that they are deemed unreliable during certain maintenance activities.	Not maintaining pipelines poses the following risks: *Safety Risk*: Inadequate gas containment by valves during an emergency situation has the potential to injure workers and the public if actuators fail to operate or if valve seals fail to fully isolate. *Financial Risk*: Failure of pipeline valves to operate as designed during an ESD has the potential to exacerbate damage to non-company infrastructure and incur commodity loss. *CSAT Risk*: Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.	The maintenance strategy for pipeline valves is to: • Assess valve condition based on SMA input and direct measurement or observation. • Complete the Pipeline Valve Inspection Program.	EGD's replacement/renewal strategy for pipeline valves is to: • Target replacement of pipeline valves and actuators to the extent needed to mitigate process safety risks. Valve replacements will be based on recent experience and understanding of SMAs. • Replace pipeline valves employed in transmission pipelines, gathering pipelines and laterals to address poor seal quality. • ESD bottles, located on many gas-powered valve actuators will be upgraded to ensure that pressure relief valves (PSV) can continue to be removed and inspected annually as required by *CSA Z662*. • Pursue opportunities to improve operations effectiveness by increasing the number of remotely controlled valves in the pipeline system. • Enhance understanding of asset health and life cycle cost for valves and valve actuators.
	Meter Stations	7	Most meter stations associated with pipelines are 10 years old or less. Meter stations have a long life expectancy but can be vulnerable to obsolescence. The Seckerton reservoir produces liquids from gas storage wells which enters the pipeline system, a combination of brine and oil that has consistently resulted in the fouling of straightening vanes and ultrasonic meter components.	Not maintaining meter stations poses the following risks: *Financial Risk*: Unmitigated obsolescence or reduction in operational reliability of meter station assets will result in substantially increased maintenance costs due to parts price increases. *CSAT Risk*: Extended lead times for parts could result in prolonged outage durations. During prolonged outages, gas supply cost to regulated customers will increase.	The maintenance strategy for meter stations is to: • Monitor parts availability and introduce generational changes in product lines. • Perform annual meter station inspections.	EGD's replacement/renewal strategy for meter stations is to: • Reduce crude oil quantity or capture crude oil carryover at the Seckerton reservoir. • Continue to enhance understanding of asset health and life cycle cost for meter stations.

1.8.4.3 Reservoirs

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Reservoirs	**Observation Wells**	40	Wells are inspected regularly through vertilog inspections. Well casings that exceed corrosion limits, as prescribed in *CSA Z341*, must be abandoned. With some exceptions, well casings are in good condition. 11 wells with microannulus leaks are being abandoned through 2017 and 2018. Crowland well design creates a situation where a single cement layer separates the inner casing from surrounding rock. The cement employed is unsuitable for sulphur-rich environments.	Not maintaining gas wells poses the following risks: *Safety Risk*: Loss of containment can pose a risk to public and worker safety. *Financial Risk*: Wells represent significant financial risk to EGD and regulated customers. Unexpected well failures carry a large replacement cost and incur product loss. *CSAT Risk*: Reduced reservoir performance may drive up gas supply costs.	The maintenance strategy for reservoirs is to: • Inspect casing internal condition (i.e., Storage Downhole Integrity Management Program) for evidence of any threat to pipe condition. • Perform vertilog inspections as prescribed by *CSA Z341*.	EGD's replacement/renewal strategy for gas wells is to: • Continue direct measurement of well condition for signs of corrosion. • Install A-1 observation wells to help validate the reservoir simulation models, verify the integrity of the reservoir boundaries, and demonstrate the relationship of low permeability zones to Lost and Unaccounted For Gas (LUF). • Periodically inject an acid solution to break down fines and precipitation of scale at the wellbore face (acidization). • Replace and install new and laneways and roads to provide adequate access to wells in compliance with *API 1171*. • Implement a Well Casings Program to address corrosion in the top two joints of the production casing. • Install new wells with associated gathering piping and temporary filtration to restore reservoir deliverability due to abandonment of older wells. • Reduce the number of Crowland wells constructed with cement unsuitable for a sulphur-rich environment and replace with new wells. • Install new reservoir observation wells to comply with *CSA Z341* requirements. • Purchase specialized well tools required to ensure reservoir personnel are equipped for continued well maintenance. • Continue to enhance understanding of asset health and life cycle cost for wells. • Follow practices on well abandonment due to corrosion as prescribed by *CSA Z341*. • Plan well replacements based on abandonment forecast and expected reduction in reservoir flow performance.
	Vertical Injection/ Withdrawal (I/W) Wells	42				
	Horizontal I/W Wells	10				
	Master Valves & Wellheads	33	Valve seal quality diminishes slightly with each actuation and is influenced by age, cycling frequency and amount of abrasive debris in the gas stream. With the exception of Crowland, the calendar age of master valves is relatively low (many less than 20 years old) and are believed to have good seal quality because of low cycle frequencies.	*Safety Risk*: Leaking master valves may not be able to provide effective isolation during emergency events or regular maintenance activities.	The maintenance strategy for master valves & wellheads is to: • Assess valve condition based on SMA input and direct measurement or observation. • Complete the Pipeline Valve Inspection Program.	EGD's replacement/renewal strategy is to replace master valves and wellheads when required. Currently, the Crowland facility is scheduled for planned replacement of master valves and wellheads.
	Emergency Shutoff Valves (ESV)	2	Valve seal quality diminishes slightly with each actuation and is influenced by age, cycling frequency and amount of abrasive debris in the gas stream. Most valves are less than five years old and are believed to have good seal quality because of low cycle frequencies. Currently, the greatest vulnerabilities of ESVs are failure to close due to freeze-off and failure to remain open due to loss of power.	ESVs provide fail safe isolation of the reservoir from surface facilities. Not maintaining ESVs pose the following risks: *Safety Risk*: Risk of injury to employees and the public during a well failure. *Financial Risk*: Risk of damage, repair costs and loss of stored gas. *CSAT Risk*: Risk of increased gas supply costs related to securing alternative gas supplies.	The maintenance strategy for master valves & wellheads is to: put and direct measurement or observation. Complete valve maintenance program.	EGD's replacement/renewal strategy for emergency shutoff valves (ESV) is to: • Purchase a portable methanol injection system to mitigate freeze-ups experienced at the emergency shut-off valves. • Install electrical supply to existing ESVs that employ solar panels. • Continue the installation of ESVs for remaining horizontal wells.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Methane Emission Reductions	N/A	The Government of Canada is committed to reducing methane emissions from the oil and gas sector by 40-45% from 2012 level by 2025. In April 2018, Environment and Climate Change Canada (ECCC) published federal methane regulations to deliver on this commitment. The requirements target two key methane sources: fugitive emissions, which are unintentional leaks from equipment leaks, and venting emissions, which are intentional releases of methane into the air.	*Financial and CSAT Risk*: Failure to comply with the new methane emissions reduction regulations could result in orders to EGD, potentially limiting the use of compression equipment until compliance is achieved. Restricted use of compression equipment could reduce deliverability and trigger the need to secure gas from alternate sources, at additional gas supply cost.	N/A	EGD's replacement/renewal strategy for methane emissions reductions is as follows: • Upgrade compressor systems to minimize its environmental impact (such as methane emissions to the atmosphere). • Develop a leak detection program for gas storage facilities. • Continue to investigate rod packing emissions to determine appropriate mitigation measures. • Continue to investigate and remediate other potential sources of methane emissions to minimize facility venting. • Continue to understand the operational and asset requirements needed to adhere to the federal methane regulations.

1.8.5 Customer Assets Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Measurement Systems • 200 and 400 Series Meters • >400 Series Meters	Dependent on meter type. Between: • 18-24 years old • 10-20 years old	**Meter Exchange Government Inspection (MXGI) Program:** This program is designed to replace meters before they fail. Meter seal life (and extensions) is based on sampling and testing to ensure Measurement Canada specifications are maintained. **Non-program:** Non-program meters that fail before the prescribed maximum service life are discovered during emergency calls or customer-initiated work. In most years, the number of meters exchanged outside of the program represents less than 1% of the population.	Failing to remove failed meters from service carries penalties under the *Electricity and Gas Inspection Act*, leading to: *Financial Risk:* Monetary penalty for non-compliance to government mandated programs. Monetary loss due to shortened life cycle of meters, related to accreditation loss. In addition, there is a financial opportunity to remove groups of meters that have been sampled multiple times with the availability of short extensions remaining.	The maintenance strategy for measurement systems are: • Meters are maintained and replaced per the Measurement Canada-prescribed regulatory program. • Meters are in scope for indoor and above-ground header leak surveys.	EGD's replacement/renewal strategy for measurement systems is through: **MXGI Program:** Continue with the MXGI program to meet or exceed regulatory compliance. Proactively replace meters as per Measurement Canada's performance testing standards. **Non-program:** Reactively respond to customer leak or other service interruption calls for non-program related meter exchanges. In addition, EGD continues to use data to project MXGI replacement volumes with a focus on leveling volumes over future years. Meters have a complete set of data that includes: quantity, age, make, size, location, and historical performance. The completeness of this data enhances the optimization of the life cycle strategy.
Regulation, Safety, and Piping Systems • 200 and 400 Series Regulator Sets	Dependent on meter and regulator type: between 20-30 years old. (~15% of the population is over 20 years old.)	Failure history and trending indicates that the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. Failure rate is 0.14% of total population.	Majority of customers are connected to the distribution system through 200 and 400 series regulator sets. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impact Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for 200 and 400 series regulator sets is to proactively maintain and replace units in conjunction with EGD's MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's proactive replacement/renewal strategy for replacing 200 and 400 series regulator sets is through: **Regulator Exchange Program:** Exchanging regulators during MXGI inspections prevents the population from reaching the wear-out phase. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Other compliance issues are corrected as part of MXGI work. Regulators are opportunistically replaced if found to be 20 years or older.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Regulation, Safety, and Piping Systems: • >400 Series Regulator Sets	Dependent on meter and regulator type: between 20-30 years old. (>50% of the population is over 20 years old.)	>400 series regulator sets have an older population compared to 200 and 400 series regulator sets. More than half of these regulator sets have regulators older than 20 years. In addition, a sample survey identified sites not adhering to current installation specifications.	>400 series regulator sets account for 2% of all EGD regulator sets and are predominantly used in commercial, industrial, or higher density residential premises. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for >400 series regulator sets is to adhere to a proactive and targeted inspection and remediation program, ensuring installation meets current code requirements. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's proactive replacement/renewal strategy for replacing >400 series regulator sets is through: **Targeted Inspection and Remediation Program**: Continuation of a targeted inspection program (commenced in 2017) to identify site-specific issues and remediate as necessary to ensure regulator sets are brought up to current installation standards. Similar to 200 and 400 series regulators, >400 regulators are opportunistically replaced if found to be 20 years or older.
Regulation, Safety, and Piping Systems: • XHP/HP to LP Delivery Regulator Sets	Dependent on meter and regulator type: between 20-30 years old.	78% of sites have some degree of corrosion. Failure history and trending indicate the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. First cut regulators were not historically replaced at the same time as second cut regulators, as per current installation standards. Approximately 65% of sites not compliant to installation specifications have been remediated.	Approximately 1% of the total regulator set population is XHP/HP. These regulator sets present a higher consequence due to higher pressures managed by two pressure cuts. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for XHP/HP to LP delivery regulator sets is to proactively maintain and replace units in conjunction with EGD's MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's proactive replacement/renewal strategy for replacing regulators is through: **Inspection and Remediation Program**: Continuation of the targeted regulator remediation program to address the remaining 35% of sites with identified compliance issues within three years. **Regulator Exchange Program:** Proactively exchanging regulators as part of the MXGI program. The first cut regulator must be exchanged if the second cut is exchanged. Exchanging regulators through the MXGI program prevents the population from reaching the wear-out phase. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. XHP/HP and LP delivery regulator sets are opportunistically replaced if found to be 20 years or older.
Regulation, Safety, and Piping Systems: • Farm Tap Regulator Sets	Dependent on meter and regulator type: between 20-30 years old.	Farm tap sites older than 15 years were determined to have more significant condition issues. First cut regulators are installed away from premises and near the property line, making them more susceptible to corrosion and third party damage. First cut regulators were not historically replaced at the same time as second cut regulators. Due to their offset location and changes in procedures, farm tap regulator sets have historically been excluded as part of inspection and maintenance work.	Less than 0.5% of the total regulator set population is a farm tap. These regulator sets present a higher consequence due to the high pressures managed by the two pressure cuts. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for farm tap regulator sets is to reactively maintain units on an as-needed basis to address customer leaks and/or emergency calls. A 1-in-10 year maintenance inspection program for farm taps is currently in place.	EGD's proactive replacement/renewal strategy for replacing farm tap regulator sets is through: **Inspection and Remediation Program:** Continuation of comprehensive farm tap inspection program and remediating identified issues where required. **Regulator Exchange Program:** Proactively exchange regulators as part of the MXGI program. The first cut regulator must be exchanged if the second cut is exchanged. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Outside of MXGI work, regulators are replaced if found to be 20 years or older.
Underground/Below-ground/Internal Piping Systems: • Service Extensions	N/A	A sample survey of service extensions shows that most subsets have a population with less than 50% cathodically protected. Further data collection is in progress to improve EGD's understanding of service extension condition.	Service extensions operate at lower pressures and enter the building below grade. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk* : Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts	The maintenance strategy for service extensions is to continue its inclusion in the Leak Survey Program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's replacement/renewal strategy for replacing service extensions is through: **Opportunistic Replacement:** Replace service extensions when the gas service is replaced. **Continuation of Data Collection**: Sampling will be used to reassess risks and validate the feasibility of an above-ground inspection tool.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Underground/Below-ground/Internal Piping Systems: • Multi-Family Building Services	N/A	A records search performed in the system to identify leaks associated with headers and header stations shows ~250-related calls between 2007 and 2015. An Integrity Survey will be initiated to validate population, collect data, and assess condition. Data collection is proposed to understand asset condition further.	Multi-family building services are comprised of buried piping systems from outdoor regulators to indoor meters located inside high-occupancy buildings. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts EGD will obtain further information on multi-family building services to better understand and manage asset risk.	The maintenance strategy for multi-family building services is to continue its inclusion in the Leak Survey Program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's replacement/renewal strategy for multi-family building services is through: **Replacement/Renewal:** Remediate high-priority condition issues identified through Integrity Surveys.
Underground/ Below-ground/ Internal Piping Systems: • Bulk Meter Headers	N/A	EGD inspected bulk meter header sites to understand condition and site factors. Common issues identified: • No clear demarcation point between EGD and customer assets • Obsolete regulators 20 years and older • Non-adherence to current installation and maintenance specifications • Vent clearances and configurations not met, not all fittings located above-ground, and obsolete components	Not maintaining bulk meter headers can lead to the following risks: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for bulk meter headers is to continue its inclusion in the Leak Survey and Corrosion Survey Programs. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's replacement/renewal strategy for bulk meter headers is through: **Delineation Definition**: Identification of a definitive delineation point between EGD and customer assets and communicating it to the customer. All company-owned plant to be included in existing maintenance, replacement, and renewal programs. **Inspection and remediation program**. Continuation of the targeted inspection and remediation program (commenced in 2017) focusing on multi-residential premises with bulk meters. Outside of MXGI work, regulators are replaced if found to be 20 years or older.
Customer Owned Systems: • Customer-owned Piping and Appliances	N/A	EGD inspects customer-owned assets at the time of initial installation and after conducting relights. 3% of customers are issued A-tags per year (identifying unacceptable conditions that present an immediate hazard).	Improperly identifying customer-owned assets for maintenance can lead to the following risks: *Safety Risk:* Loss of containment *Financial Risk:* Emergency response *CSAT Risk:* Reputational impacts	The maintenance strategy for customer-owned assets is to continue the issuance of tags that drive the customer to address compliance issues (through the Appliance inspection Program). Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's strategy for customer-owned systems includes: • Plan-Do-Check-Act process on data/programs to drive policy changes, communication updates, and targeted inspection programs. • Collection of data to refine risk assessment. • Timely communication to customers about the need to repair/replace assets, as applicable.

1.8.6 Real Estate and Workplace Services Condition and Strategy Overview

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M^2)	BUILDING AREA (SF/M^2)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
Kennedy (Operations Centre)	58	3.4/13,759	20,428/1,897	Owned	Building operation impacted by the physical separation of the office and warehouse. The building does not meet Ontario Building Code (OBC) barrier-free accessibility and universal design standards. Some staff are seated at the mezzanine level, which has a low ceiling, no natural light access, and space constraints. 100% of the furnishings are not compliant with EGD standards. The facility's current condition is	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Hindered operations and administrative functions *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Kennedy Road Expansion**: Acquire adjacent property and build a new facility on the combined site.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M²)	BUILDING AREA (SF/M²)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
					considered not correctable at the current location.			
Station B (Operations Centre)	50	3.2/12,950	6,744/626	Owned	The building is too small to accommodate current staff and does not meet OBC barrier-free and universal washroom standards. At this facility, 100% of the furnishings are not compliant with EGD standards. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Lack of dedicated operational area *Financial Risk:* Hindered operations and administrative functions *CSAT Risk:* GHG emission and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Station B New Building Construction On Existing Site**: Build a new two-storey building while maintaining the area of the existing yard.
Kelfield (Operations Centre)	58	1.04/4,209	7,381/685	Owned	Staff does not have access to daylight and views. The building does not meet OBC barrier-free accessibility and universal washroom standards. The building is too small to accommodate required uses. 100% of the furnishings are and not compliant with EGD standards. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents *Financial Risk:* Inefficient energy consumption, hindered operations and administrative functions *CSAT Risk:* GHG emission and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Kelfield Facility Site Acquisition and New Building Construction**: Increase the site area by acquiring the abutting property and building a new two-storey facility, increasing the existing yard size.
Brampton – Colony Court (Operations Centre)	20	3.0/12,139	13,607/1,264	Owned	Staff does not have access to daylight and views. The building does not meet OBC barrier-free accessibility and universal washroom standards. The warehouse is not properly equipped for efficient operation. 6% of the furnishings is compliant to EGD standards. 94% is non-compliant. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption, hindered operations and administrative functions *CSAT Risk:* GHG emission and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Brampton Facility Expansion**: Correct physical and functional deficiencies by expanding the existing facility on the existing site.
Brockville (Operations Centre)	48	1.15/4,654	3,998/371	Owned	The building is too small to meet requirements and office space lacks needed amenities. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings are not compliant with EGD standards. The facility's current condition is considered not correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents *Financial Risk:* Inefficient energy consumption, hindered operations and administrative functions *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Brockville Facility Relocation**: Sell the existing property and purchase a property suitable in size to accommodate the required program.
Thorold (Regional Operations & Administrative Centre)	26	8.14/32,979	83,302/7,739	Owned	Staff does not have access to daylight and views. The building does not meet OBC barrier-free accessibility and universal washroom standards. 9% of the furnishings is compliant to EGD standards. 91% is non-compliant. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents *Financial Risk:* Inefficient energy consumption *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Thorold Facility Renovation and Parking Lot Expansion**: Correct physical and functional deficiencies by completing an interior renovation and expanding the parking lot to alleviate existing deficiencies.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M²)	BUILDING AREA (SF/M²)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
Oshawa (Operations Centre)	29	3.89/15,742	12,050/1,119	Owned	The building is too small to meet requirements. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings is not compliant with EGD standards. The facility's current condition is considered not correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption, hindered operations and administrative functions *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Oshawa Facility Renovation** : Correct the physical and functional deficiencies by renovating and renewing the existing facility on the existing site.
Ottawa-Coventry (Regional Operations & Administrative Centre)	53	4.93/19,951	77,210/7,173	Owned	The building footprint is too large and has a complicated layout, contributing to decreased staff productivity and efficiency. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings are legacy and not compliant with EGD standards. The facility's current condition is not considered correctable at the current location, however, consolidation with the South Merivale Operations Centre (SMOC) is recommended to eliminate service coverage area duplication.	The property has been assessed to have the following risks: *Safety Risk:* motor vehicle incidents *Financial Risk:* Excessive footprint, high operating costs *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Ottawa-Coventry and SMOC Consolidation**: Sell the existing properties and purchase a property suitable in size to accommodate the SMOC and Coventry Road programs.
South Merivale Operations Centre (SMOC)	23	3.98/16,129	26,732/2,483	Owned	The site and building shared with another tenant. Site function is inefficient. The building does not meet OBC barrier-free accessibility and universal washroom standards. The facility's current condition is considered correctable at the current location, however, consolidation with the Coventry Road office is recommended to eliminate service coverage area duplication. 27% of the furnishings is compliant to EGD standards. 73% is non-compliant.	The property has been assessed to have the following risks: *Safety Risk:* Pedestrian injuries *Financial Risk:* Excessive footprint, high operating costs *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	
Peterborough (Operations Centre)	37	1.12/4,569	5,720/531	Owned	This building and site are too small to meet requirements. The building does not meet OBC barrier-free accessibility and universal washroom standards. At this facility, 100% of the furnishings are non-compliant with EGD standards. Its current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents *Financial Risk:* Inefficient energy consumption *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Peterborough Site Relocation and New Facility Construction**: Purchase a vacant property to build a new facility.
Arnprior (Operations Centre)	48	6.15/24,919	4,420/410	Owned	The building is lacking access to daylight throughout the warehouse, garage, and muster room. It also lacks proper locker and shower facilities. The building does not meet OBC barrier-free accessibility and universal washroom standards. At this facility, 100% of the furnishings are non-compliant with EGD standards. Its current condition is considered correctable at the current	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption and operations *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Arnprior Facility Expansion**: Correct the physical and functional deficiencies by renovating and renewing the existing facility on the existing site.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M^2)	BUILDING AREA (SF/M^2)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
					location.			
Barrie (Operations Centre)	13	5.18/20,969	7,493/696	Leased	Reports indicate odors leak from the warehouse into office space due to lack of fume extraction arms. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings are legacy and not compliant with EGD standards. Current condition is considered correctable at current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption and operations *CSAT Risk:* GHG emissions and environmental impact	The landlord is accountable for core and shell maintenance activities. The current building maintenance schedule for EGD's tenanted portion of the property is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Barrie Facility Expansion**: Purchase the existing property in its entirety and expand into the adjacent tenant space area.
VPC (Head Office)	51	15/60,703	348,787/32,403	Owned	On unrenovated floors, staff have insufficient access to daylight and views. The lack of an adequate number of elevators causes delays and productivity loss. The building envelope is more than 50 years old. A pending engineering study was proposed to assess core and shell condition. The emergency power generator onsite is obsolete and a program is in place to replace it. 86% of the furnishings is compliant to EGD standards. 14% is non-compliant. The facility's current condition is considered correctable at the current location. The Mechanical Services Building was built in 1969 and is no longer capable of accommodating the volume and specialized needs of the operation.	The property has been assessed to have the following risks: *Safety Risk:* Building envelope failure *Financial Risk:* Inefficient energy consumption, operations and advanced age *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and proactive at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	VPC strategies include: • **VPC Facility Renovation**: Correct physical and functional deficiencies by renovating and renewing the facility on the existing site. • **VPC Emergency Life-Safety Systems Backup Power Replacement** • **VPC Core and Shell Obsolescence Study** • **New Mechanical Services Building Build-out**
TOC (Regional Operations & Administrative Centre)	7	11.1/44,920	99,620/9,255	Owned	This facility is relatively new and meets EGD standards. The Engineering Materials Evaluation Centre (EMEC) requires additional space to adequately operate for its designed function. 100% of the furnishings are compliant to EGD standards and there are no plans to replace furniture.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Third-party laboratory expenses *CSAT Risk:* None	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**TOC Facility Expansion**: Expand the laboratory and warehouse facilities in the EMEC for required operations.
Tecumseh Engineering (Operations Centre)	9	4.8/19,425	10,695/993	Owned	This facility is relatively new and meets EGD standards. 100% of the furnishings are non-compliant with EGD standards.	None.	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	Maintain existing facility .
Tecumseh Gas Storage (Operations	2	10/40,469	41,817/3,884	Owned	This facility is brand new and meets EGD standards.	None.	The current building maintenance schedule is proactive for preventative	Maintain existing facility.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M²)	BUILDING AREA (SF/M²)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
Centre)					100% of the furnishings are compliant to EGD standards and there are no plans to replace furniture.		maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	
Furniture & Ergonomics	N/A	N/A	N/A	Owned	The assets associated with furniture and ergonomic blanket include all EGD furniture assets. The blanket addresses office and meeting room furnishings and ergonomic requirements. Benefits of the furniture program: • Ergonomic support • Daylight and views for building occupants through the use of mid-height panel systems • Task seating to address a range of body types • Consistent workstation configuration • Lower operating costs by contributing to fixed environments that allow a broad range of administrative requirements without change	Without adequate furniture and ergonomics in place, EGD is exposed to financial risk as productivity can potentially suffer due to inefficient space allocation and unnecessary workstation re-configuration costs. Improper ergonomics support can pose a safety risk as lack of task seating that addresses a range of body types and needs can potentially cause repetitive strain injuries.	N/A	The renewal /replacement strategy for furniture and ergonomics assets is to replace office and meeting room furnishings as required due to failure, ergonomic modifications, and tools as recommended by an ergonomist and/or the EGD Health Centre for the prevention of repetitive strain injuries and the needs of return-to-work employees.
Cabling	N/A	N/A	N/A	Owned	The assets associated with cabling projects include all cabling assets that span across the entire organization. This project covers break-replacement of defective cabling infrastructure as well as new cable installations.	If cabling systems are not maintained as needed, it potentially poses a financial risk to EGD due to a loss of productivity stemming from the loss of connectivity to EGD's networks and systems.	N/A	The renewal /replacement strategy for cabling assets is to maximize asset useful life and replace cabling upon failure. The nature of the work involves the replacement of non-functioning and new data cabling.
Workplace Transformation	N/A	N/A	N/A	N/A	Current office layouts are not supportive of an activity-based environment and require renovation to create workspaces with increased utilization by having fully unassigned seating and over-assignment of staff to ensure a high utilization rate of workspace assets.	Inefficient use of workspaces poses a financial risk to EGD as inadequately used space can potentially lead to higher costs to maintain unused and unneeded space.	N/A	The renewal /replacement strategy for workspace assets is to create a flexible work environment to maximize EGD's space utilization for effective use of its facilities, fostering mobility, collaboration and productivity. EGD plans to update office environments to better suit flexible work arrangements designed with greater density, shared workspaces, and supporting technologies.
Building Systems	N/A	N/A	N/A	Owned	A third-party engineering consulting company was employed by EGD to analyze factors such as age of equipment, maintenance records, repair cost, building standards, and compliance issues to determine overall risks and the replacement timing of heating, ventilation, air conditioning (HVAC) equipment, plumbing, electrical systems, building envelope, facilities equipment, and exterior site improvements.	If building systems are not properly maintained, there is financial risk to EGD as the failure of these systems increases substantially, which can potentially lead to loss of use and decreased staff productivity.	N/A	The renewal /replacement strategy for building systems assets is to maximize equipment useful life and replace building systems before failure, including the replacement of the building envelope, HVAC, and electrical systems to current environmental standards, ensuring interior comfort and overall security.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M^2)	BUILDING AREA (SF/M^2)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
GHG Energy Reductions	N/A	N/A	N/A	Owned	EGD has started a third-party study on energy efficiency and emissions for its office buildings. The study identifies operational improvements needed to ensure building systems are operated efficiently to reduce natural gas use.	Existing facilities use more energy than a comparable new or renovated facility (using current OBC and energy standards), which poses the following risks: *Financial Risk*: Reduction in operating costs *CSAT Risk*: Existing facilities emit more greenhouse gases that can potentially affect ratepayers.	N/A	Existing building commissioning is underway at VPC and TOC. Planned completion is slated for 2018 to ensure retro-commissioning covers seasonal systems. The retro- commissioning process will identify a mix of measures with a range of implementation costs and energy/GHG savings. Once completed, the Retro-commissioning and Building Operations teams will develop measures and action plans for energy conservation measure implementation, verification, and ongoing commissioning. Lessons learned will be implemented on other building improvement projects.

1.8.7 Fleet and Equipment Condition and Strategy Overview

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Fleet	**Light Duty Vehicles**	5.3	Analysis indicates that average maintenance costs exceeds the market value of a light duty vehicle at an approximate age of six years or 180,000 km.	Aging light duty vehicles pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	Vehicle maintenance every 8,000 km (approximately every three months).	**Light Duty Vehicle Replacement Strategy**: This proactive program replaces approximately 50 light duty vehicles per year to maintain an average age of at or less than six years old over the 10-year span of this Asset Management Plan.
Fleet	**Medium Duty Vehicles**	7	Analysis indicates that average maintenance costs exceeds the market value of a medium duty vehicle at approximately 10 years old.	Aging medium duty vehicles pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	Vehicle maintenance every 10,000 km or 500 engine hours (approximately every four months).	**Medium Duty Vehicle Replacement Strategy**: This proactive program replaces approximately 10 medium duty vehicles per year to maintain an average age of at or less than 10 years old over the span of this Asset Management Plan.
Heavy Equipment	**Backhoes**	10	Analysis indicates that average maintenance costs exceeds the market value of heavy equipment at approximately 10 years old.	Aging heavy equipment assets pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	Equipment maintenance is conducted on a scheduled basis, ranging from three to six months, depending on the type of equipment.	**Heavy Equipment Replacement Program**: This proactive program is based on average historical spending (renewing or acquiring approximately two heavy equipment assets per year) and is driven by: • Proactively replacing assets based on a detailed physical condition assessment • Reactively acquiring net new equipment based on business needs.
Heavy Equipment	**Trailers**	10				
Heavy Equipment	**Forklifts**	12				
Heavy Equipment	**Welders**	9				

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Directional Drilling Equipment	7				
Tools	N/A	The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations.	Aging, broken, or inadequate tools pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	N/A	A reactive **Tools Replacement Program** is in place to address tools that are: • Showing signs of wear and tear, broken, and/or unrepairable • Stolen or lost • Declared obsolete by the manufacturer or supplier • No longer approved for use due to updated Engineering standards and practices • Needed and requested by EGD operating departments to perform their business functions (a tool requisition form is submitted)

1.8.8 Technology and Information Services Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Laptops and Desktops	4	Laptops and desktops tend to experience performance issues and failures in their fourth year of operation.	Aging laptops and desktop assets primarily pose a financial risk to EGD as non-performing assets result in a reduction in productivity and an increase in maintenance costs.	Reactive maintenance as required through service requests.	**Laptop/Desktop Renewal Strategy**: EGD's strategy is to replace laptops and desktops every four years. For the majority of their life (three years), these assets are under warranty. This strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.
Desktop Sustainment	N/A	The condition and health of desktop sustainment equipment is not proactively monitored.	Aging and/or inadequate desktop sustainment equipment pose the following risks to EGD: *Safety Risk* : Compromises the health and safety of employees who require specific equipment for ergonomic purposes *Financial Risk*: Reduction in productivity	Reactive maintenance as required through service requests.	**Desktop Sustainment Equipment Strategy**: Desktop sustainment equipment is provided on an as-needed basis. The replacement of desktop sustainment equipment is based on the following circumstances: • Equipment is damaged, broken, or malfunctioning. • Equipment is required based on employee ergonomic assessments. • Equipment is required for new employee and contractor hires.
Software: Packaged & Developed Applications	10	A number of packaged and developed applications require updates to: • Meet business requirements and/or maintain the ability to enhance and support existing applications • Meet vendor support requirements for hardware • Meet vendor support software life cycles (for packaged applications) • Improve the quality of customer experiences (informed by customer engagement results)	There are a number of consequences to EGD if its applications are not maintained, renewed or enhanced when needed. These risks include: *Safety Risk:* This risk increases if systems providing operational functionality for emergency calls encounter issues and are unavailable. *Financial Risk:* • Inability to meet business needs and requirements, reducing overall productivity • Decreased productivity due to extended application and system outages • Outages, application downtime, and potential security breaches result in loss of revenue • Inability to meet financial and reporting compliance	Maintenance releases and software bug fixes are rolled out regularly as a means of reactively maintaining the performance of packaged and developed applications.	**Proactive Software/Hardware Renewal Strategy**: EGD has a proactive replacement strategy to keep software and hardware current and supported. The specific replacement strategy is dependent on changing business requirements or due to an application solution becoming unsupported by its vendor. The following applications require upgrade/renewal over the next three years: • Enbridge Meter and Reporting (EnMar) is being replaced by a solution using Customer Information System (CIS) and Work and Asset Management Solution (WAMS). • Demand Side Management (DSM) is being replaced by a packaged solution. • The EGD extranet is being replaced by a packaged solution. • The Meter Reading System (MVRS) is being partially replaced by a custom meter reading application in 2018, and some existing components that must remain on MVRS are being upgraded. • The Land Management system (LAMPS) is being replaced. • The Datapak application will be replaced.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
			requirements • Increased maintenance costs due to reactively addressing required software and hardware repairs *CSAT Risk:* • Cybersecurity exposure due to the inability to apply security patches to end-of-support software, which could also affect EGD's reputation if any breaches occur • Customer satisfaction could suffer if client-facing systems are unavailable The following opportunities were identified for packaged, developed, and infrastructure applications: *Financial Opportunity:* Significant operating and maintenance cost savings opportunities associated with customer experience enhancements *CSAT Opportunity*: Improved self-service customer experiences due to enhanced functionality associated with software updates		• The Business Development Datamart (BDDM) is to be migrated to SAP Business Warehouse (SAP BW). • The iViewer application will be replaced by a more robust records storage repository. **Customer Experience Strategy**: EGD has a Customer Experience Transformation project, consisting of initiatives that span multiple asset subclasses within the TIS asset class. This two year project proactively transforms the way we do business with our customers and to improve customer interactions.
Software: Infrastructure Applications	12	There are a number of application infrastructure assets that require updates to: • Meet vendor support software life cycles • Support key foundational software required for in-use/predicted applications.		Maintenance is reactive - performance issues or software bugs are addressed as they are identified.	**Application Infrastructure Renewal Strategy**: A proactive replacement/refresh strategy is in place, driven by forecasted changes to existing software products and business requirements.
Mobile Devices	3	The condition of mobile devices is not proactively monitored.	Not maintaining mobile devices primarily results in a safety risk for EGD because the inability to respond to emergency field situations and to resolve off-hours on-call situations will potentially be compromised, jeopardizing the reliable and safe operations of TIS systems and applications.	Mobile devices are maintained internally to address performance issues. Damaged devices are repaired on an as-needed basis within the three-year replacement window.	**Mobile Device Renewal Strategy**: EGD's replacement strategy is aligned with industry best practices with replacements planned for every two to three years (aligned with smartphone manufacturers' release cycles and typical data plan contracts).
Field Devices	4	The condition of field devices is not proactively monitored. Due to exposure to tough working conditions, field devices experience significant wear and tear. (breakage and performance issues generally occur in their fourth year of use).	Not maintaining field devices primarily results in financial risk for EGD as it will potentially contribute to productivity loss. The efficiency of field work will be compromised due to devices being unavailable. Travel time will increase between the office and job sites.	Maintenance repairs and replacements are performed as needed through service requests.	**Field Device Renewal Strategy**: Most EGD field devices have a four-year proactive replacement strategy driven by industry best practice. Some assets, such as truck modems, are reactively replaced as needed.

1.8.9 Business Development Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Large and Utility Natural Gas for Transportation (NGT) Stations	15	Third-party and internal compressor inspection results indicated that 13 sites were over 3,000 operating hours (the manufacturer recommendation) and showed signs of deterioration, requiring a compressor rebuild. General wear and tear on asset components was also identified (e.g., worn valve faces, gaskets, etc.) as needing replacement.	Failure to maintain Natural Gas for Transportation (NGT) assets will result in declining equipment health, which could lead to the following risks: *Safety Risk*: Loss of containment *Financial Risk*: Repair, commodity loss, and potential property damage costs *CSAT Risk*: GHG emissions, negative environmental impact, and reputational risks	Bi-weekly onsite operational inspection of station components.	The strategy for existing large and Utility NGT stations is to have a program that: • Uses condition information based on periodic on-site inspections to maintain station integrity and supply reliability • Proactively replaces compressor blocks • Proactively upgrades equipment components as new technology becomes available • Updates station records to be compliant with Engineering standards In addition, EGD has a strategy to service new NGT large station customers, and to install and maintain the necessary fueling equipment. Business Development's marketing and execution teams work together to ensure successful implementation.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Small NGT Stations/ Vehicle Refueling Appliance (VRA)	30	General wear and tear on asset components was identified through a condition assessment (e.g., worn valve faces, gaskets, etc.) as needing replacement.	Failure to maintain NGT assets will result declining equipment health, which could lead to the following risks: *Safety Risk*: Loss of containment *Financial Risk*: Repair, Commodity loss, and potential property damage costs *CSAT Risk*: GHG emissions, negative environmental impact, and reputational risks	Quarterly onsite operational inspection of station components.	The strategy for existing Vehicle Refueling Appliance (VRA) stations is to have a program that: • Uses condition information based on periodic on-site inspections to maintain station integrity and supply reliability • Proactively replaces and upgrades VRA compressors and remote panels In addition, EGD has a strategy to service new VRA station customers, and to install and maintain the necessary fueling equipment. Business Development's marketing and execution teams work together to ensure successful implementation.
Community Expansion	N/A	N/A	Community expansion is a growth opportunity to provide natural gas services to communities not currently being serviced by EGD.	Assets will be maintained according to their asset specific requirements (outlined in the appropriate asset class section).	EGD's **Community Expansion Strategy** is to continue assessing and pursuing opportunities to provide gas distribution service to under-served communities. The process will require submitting applications to the Ontario Ministry of Infrastructure for approval to proceed as well as the subsequent submissions of Leave to Construct (LTC) applications to the OEB.
Lower-carbon Strategies	N/A	N/A	Lower-carbon strategies are a growth opportunity in line with the province's overarching climate change initiative to achieve GHG reductions and reduce negative environmental impact.	Assets will be maintained according to their specific requirements.	**Lower-carbon strategies** include exploring alternative energy sources, such as: • Energy Efficiency or DSM • Renewable Natural Gas (RNG) • Hydrogen Blending (Power-to-Gas) • Geothermal For the purposes of this Asset Management Plan, these lower-carbon initiatives (with the exception of DSM and hydrogen blending) are not currently included in rate-regulated activities, but are included in this Asset Management Plan to outline these important business development strategies for EGD.

1.9 CAPITAL EXPENDITURE

The EGD capital plan was optimized from 2019 to 2028 using the Asset Management Core Process (outlined in **Section 4.2**). The result addresses the organization's asset needs and includes known risks and opportunities requiring action over the next 10 years.

The portfolio optimization process examined 754 business cases for which 100%* of the capital request was risk assessed. The optimization considered business cases developed to address:

- Asset class objectives and life cycle strategies
- Known compliance requirements
- Identified risks within EGD's intolerable risk region
- Identified risks requiring a solution within a defined time window

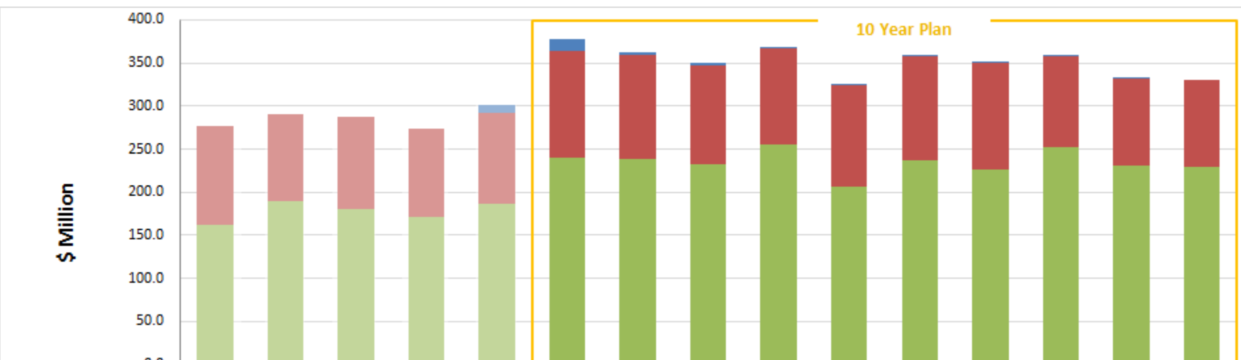
**Note: Projects that are less than $100K and mandatory without a risk assessment are not included in this calculation.*

As described in Portfolio Optimization (**Section 4.2.3**), project timing was determined based on risk reduction and projects identified as mandatory, which had specific timing requirements and mandates. Labour implications were also considered for routine maintenance activities to ensure that project pace and timing met life cycle strategies, adequately reduced risk, and were feasible.

The capital expenditure requirements fall into three categories:

- **Growth Capital:** Customer growth and reinforcement expenditures that will support the addition of new customers.
- **Maintenance Capital:** Expenditures related to existing assets to maintain safe and reliable business operations.
- **Community Expansion:** Expenditures for the expansion of the gas distribution network to remote communities that do not meet current *EBO 188* economic feasibility guidelines without a rate rider.

Figure 1.9-1 presents the direct 10-year capital profile and excludes capital overheads for EGD from 2019 to 2028, totaling over $3.5B in proposed asset expenditures.



	2014	2015	2016	2017	2018 B	2019 F	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
Community Expansion					9.8	13.3	3.0	3.1	2.0	1.3	0.7	0.7	0.5	0.7	0.0
Growth	114.5	101.8	106.7	101.7	104.7	123.2	121.9	114.6	111.8	118.4	122.1	123.4	104.9	101.7	101.3
MTC	162.5	189.0	179.8	171.3	186.5	240.4	237.7	232.8	254.8	206.0	236.2	226.4	252.6	230.0	228.6

Figure 1.9-1: EGD 10-year Capital Profile (2019 – 2028)

The overall portfolio has an LRROI of 119%. The breakdown by asset class has been summarized in **Table 1.9-1**. While different asset classes have higher or lower LRROI values, the value of the lifetime risk reduced is greater than the capital investment.

Table 1.9-1: Total LRROI

ASSET CLASS	LRROI
Business Development	110%
Customer Assets	136%
Customer Growth	164%
Fleet & Equipment	108%
TIS	162%
Pipe	41%
Real Estate Services	101%
Stations	82%
Storage	284%
Total	**119%**

Although outlined in **Section 5** as assets requiring attention and further investigation, projects with solution scopes still under development are not included in the 10-year portfolio of spend (outlined in **Table 1.9-2**). As these solutions are confirmed, they will be incorporated into EGD's 10-year plan.

Table 1.9-2: Capital Range and Timing for Projects Under Development

		Estimate/Range of Required Capital	In Service Year(s)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Storage	Corunna Renewal	$90M - $150M	2022										
	Crowland Renewal	$10M - $15M	2021										
Business Development	NGT Rental Compressors - Transit	$10M - $40M	2022										
Pipe	NPS 20 Lake Shore KOL Replacement - Parliament to Bathurst	$65 - $150M	2026										
	Rideau Reinforcement	~$55M	2023										
	York Region Reinforcement	~$60M	2022 | 2026										

1.9.1 Capital Considerations

The optimization process is based on EGD management setting a capital constraint or threshold from which the asset management leveling tool creates a portfolio of work driven by asset needs. The capital constraint, termed *optimization capital*, is determined based on the defined regulatory framework and asset class objectives and strategies. It may be necessary to run iterative optimization scenarios varying the optimization capital to determine the level of capital that best meets asset needs; this method is used when no capital constraints are provided.

To complete EGD's latest portfolio optimization, the outcome of the MAADs decision and future impact to ratepayers were considered when establishing the optimization capital. On August 30, 2018, the Decision and Order was received from the OEB on the application to amalgamate EGD and UGL using an established regulatory framework for MAADs *[EB-2017-0306/EB-2017-0307]*. This decision provided EGD with the approved five-year (2019-2023) annual Incremental Capital Module (ICM) Materiality Threshold. EGD has been approved by the OEB to have access to rate recoveries for qualifying incremental capital investments over and above the materiality threshold through the ICM. The ICM Materiality Threshold was used to determine EGD's optimization capital from 2019 - 2023. For the years 2024 – 2028, the annual capital budget will represent management's spend threshold for each year that they feel best meets ratepayer rate impact with the utilities obligation to serve and maintain its plant (all rate base). **Table 1.9-3** summarizes EGD's optimization capital for the 10-year plan.

Table 1.9-3: Capital Constraint Determination

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM Materiality Threshold[1]	463 M	473 M	479 M	483 M	487 M	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Total Overhead	151 M	154 M	156 M	158 M	165 M	168 M	171 M	174 M	177 M	180 M
Optimization Capital	312 M	319 M	323 M	325 M	322 M	323 M	324 M	325 M	326 M	326 M

EGD's capital spend requirements up to the OEB-approved ICM Materiality Threshold is referred to as *base capital*. To understand which projects would be considered incremental and potentially ICM-eligible, EGD applied the following descriptions of *base capital* and *incremental capital* to business cases for optimization:

Table 1.9-4: Base Capital & Incremental Capital Descriptions

TERM	DESCRIPTION
Base Capital	• Represents the ongoing capital requirements of the utility to maintain safe and reliable operations, to economically attach new customers, and to pursue opportunities for innovation • Driven by asset class strategies and programmatic work that has sufficient history and risk to warrant continuation • Supported by existing rates (through depreciation expense, annual Price Cap Index rate increases, or incremental revenues from customer growth)
Incremental Capital	• Represents discrete projects requiring an in-service capital investment of over $10M (from 2019-2023) • Refers to non-discretionary spend driven by asset class strategies and not supported by existing rates • Total incremental spend will include all capital costs associated with the identified project (including multi-year spend that falls outside of the project's in-service year when the ICM is to be requested).

To optimize 754 business cases, EGD's PowerPlan Asset Management Planning (PP-AMP) leveling tool was used (refer to **Section 4.2.3**) where the optimization capital was set as the constraint (excluding overhead). Based on this value, the optimal capital timing was determined for proposed business cases.

1.9.2 Optimization Results

Portfolio optimization uses data from the most recent approved plan; the initial spend profile is the result of the previous optimization and approved portfolio, with the addition of new business cases and updates to existing ones. The initial pre-optimized request for capital exceeded the optimization capital in all years but 2028 (represented by the red line in **Figure 1.9-2**).

[1] Refer to Table 1.10-1 in **Section 1.10**.

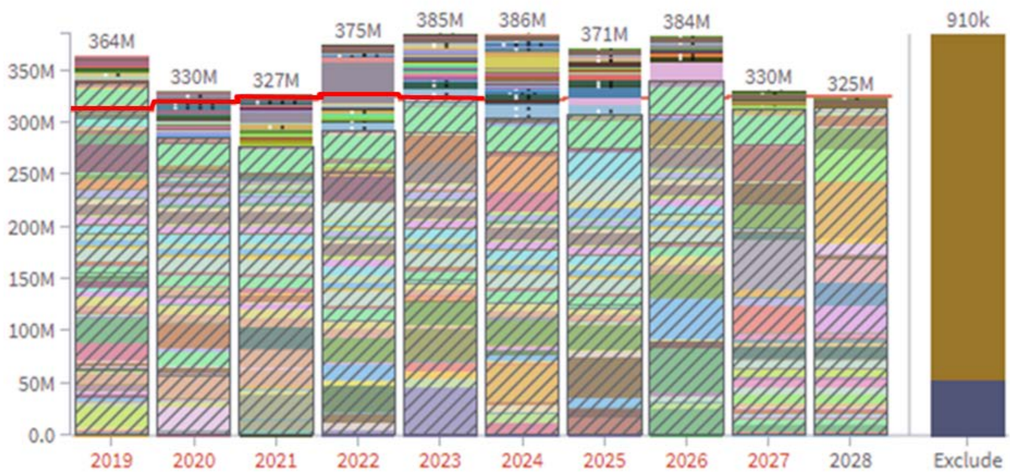


Figure 1.9-2: Pre-Optimized Spend Profile (PP-AMP Leveling Tool View)

When running the leveling tool (as detailed in **Section 4.2.3**) at the defined optimization capital, an optimized solution could not be obtained, due to the level of fixed and mandatory projects. To resolve this, business cases that met the incremental capital criteria were removed the leveling process and leveling was repeated until an optimized solution was obtained. Since ICM-eligible capital is different from initiatives carried out through base capital, removing these initiatives from leveling provided EGD with the best understanding of an optimized typical base spend profile. ICM-eligible business cases (presented in **Table 1.9-5**) were considered in addition to the optimized result. Where possible, through subsequent reviews of the results, ICM-eligible capital was proposed within the optimization capital and treated as base capital. The optimized result is illustrated in **Figure 1.9-3**.

Table 1.9-5: ICM-Eligible Capital Projects

ASSET CLASS	PROJECT NAME	DRIVER[2]	IN SERVICE YEAR	TOTAL IN-SERVICE CAPITAL ($000S)
Pipe	NPS 30 Don River Replacement	Exceeds risk threshold	2019	$25,700
Pipe	NPS 20 Don River Relocation	Third party relocation	2020	$35,873
Storage	SCOR: Meter Area Upgrade	Exceeds risk threshold	2020 | 2021	$43,600
Pipe	NPS 12 St. Laurent Ottawa North Main Replacement	Condition	2022	$52,132
REWS	Kennedy Road Expansion[3]	Condition	2022	$21,700
Pipe	NPS 12 Martin Grove Road Main Replacement Phase 2	Condition	2024	$11,750
REWS	VPC Core and Shell Obsolescence	Condition	2025	$20,000
REWS	SMOC/Coventry Consolidated Facility	Condition	2026	$30,825

[2] For details on these projects, refer to each asset class's Condition and Strategy Overview (outlined in **Section 5**).
[3] This project was proposed within the optimization capital and treated as base capital.

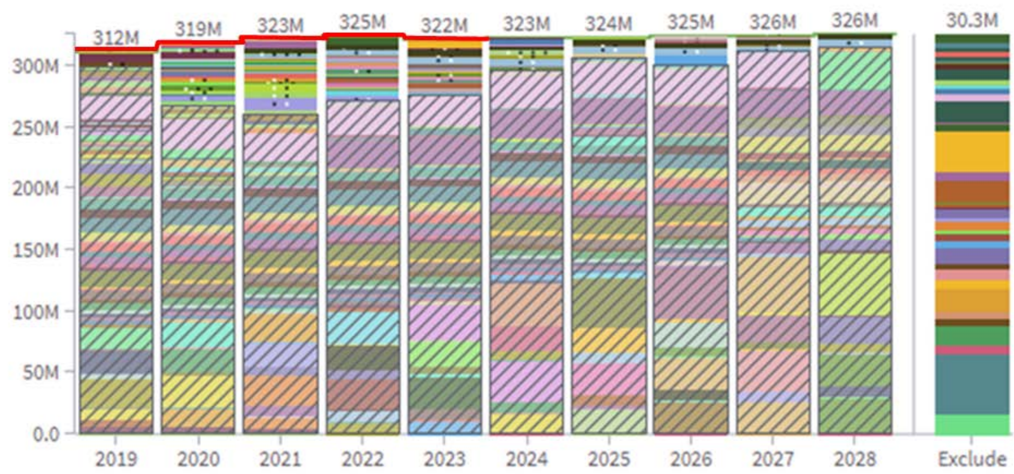


Figure 1.9-3: Post-Optimized Spend Profile (PP-AMP Leveling Tool View)[4]

The optimized result and ICM-eligible projects were reviewed with Asset Class Managers (ACM), Asset Class Directors (ACD), and business stakeholders. Adjustments to these results were proposed and reviewed with all asset classes. These adjustments were driven by resource capacity, re-alignment with life cycle management strategies, and where possible, maintaining a total spend within the optimization capital. Adjustments were incorporated as necessary through consultation with the ACMs and using Lifetime Risk Return on Investment (LRROI) for project comparison.

Figure 1.9-4 presents the 10-year capital requirements by asset class. It can be seen that the capital requirements to meet asset class objectives and life cycle management strategies, while managing risk, exceed the capital available for optimization. From 2019-2023, the capital that exceeds the optimization capital (ICM Materiality Threshold less Total Overhead), qualifies as incremental capital per the definition in **Table 1.9-4**.

The final 10-year portfolio of spend was reviewed and approved by the ACDs and the Asset Management Steering Committee.

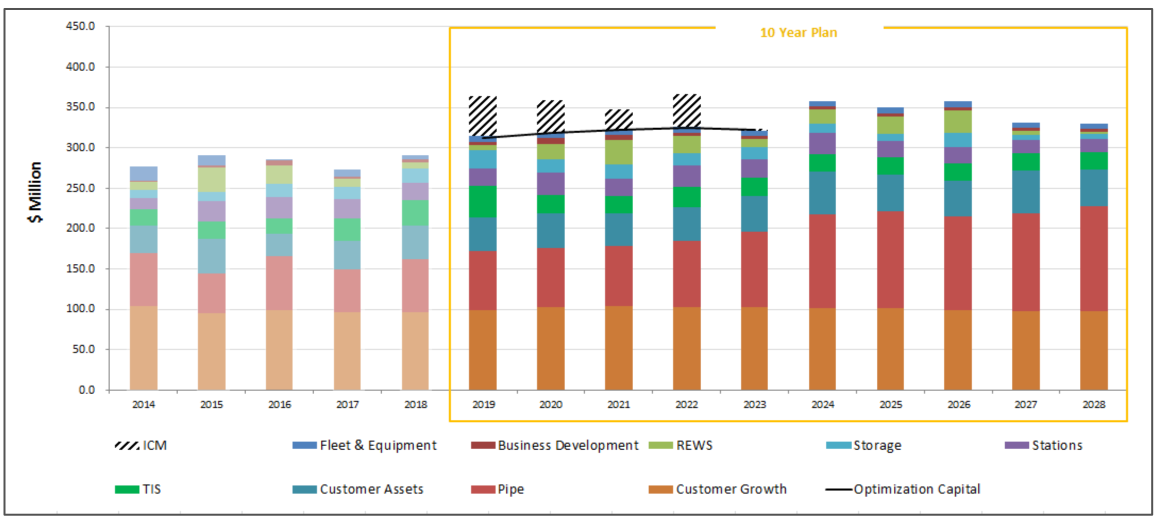


Figure 1.9-4: Final 10 Year Plan by Asset Class (with ICM)

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[4] This profile does not include ICM-eligible projects.

1.10 ASSUMPTIONS

The 10-year capital plan is based on the best available information at the time of completion. Key assumptions detailed in the tables below provide a basis for interpretations.

Table 1.10-1: Assumptions for All Categories

ASSUMPTION	BASIS FOR ASSUMPTION
Optimization results are based on available information as of September 2018.	Based on EGD's Portfolio Optimization process, the portfolio of spend is determined through the completion of PP-AMP leveling and subsequent reviews.
Future costs are valued at 2018 Present Value.	Current practice forecasts projects based on 2018 rates. An annual inflation factor of 1.73% was applied to programs with defined scope/unit rates (such as meter purchases, customer growth, service relays).
All cost estimates are based on available information as of August 2018.	Using EGD's Value-Based Asset Management Model, these requirements will be reviewed and revised as required.
All risk assessments are based on risk models and methodology as of August 2018.	Using EGD's Value-Based Asset Management Model, the Risk Management Framework will be reviewed and revised as required.
Projects in flight that span over multiple years must continue until complete.	Once a project is in progress, it is inefficient and costly to terminate.
Capital overhead costs are not included in the Asset Management Plan.	The following direct costs are incremental to the capital requirements outlined in this plan: Direct Labour Costs, Interest During Construction, Administrative and General, and Extended Alliance (EA) Fixed Overheads.
Historical actual costs are valued at years' actual value.	Historical values are not adjusted to be expressed in present value.

Table 1.10-2: Renewal Assumptions

ASSUMPTION	BASIS FOR ASSUMPTION
Asset health provides a reasonable representation for asset condition and remaining asset life for forecasting purposes.	Reliability engineering is used to understand asset health. Based on projected life cycles, consequences of failure, tacit knowledge, and asset data, risk is quantified. Renewal projects are planned to reduce this risk to the lowest practicable level.
Optimization of renewal projects produces a forecast that maintains an acceptable level of risk to the organization.	

Table 1.10-3: Customer Growth Assumptions

ASSUMPTION	BASIS FOR ASSUMPTION
Customer growth is forecasted using historical trends and economic projections for the planning period.	The Customer Growth Forecast considers new housing starts, meetings with builders and developers, municipal growth forecasts, general economic indicators, and projections provided by specialized external consultants to combine localized trends with macro-economic factors.
Load forecasting is based on the current understanding of temperature inputs and estimated customer consumption.	EGD is evaluating the scope of its carbon strategy and subsequent impact on customer growth forecasts. Various technologies (such as smart thermostats) and Energy Efficiency programs (such as Demand Side Management) are being assessed to determine potential impact on peak hour demand in the ongoing Integrated Resource Planning (IRP) study as directed through *[EB-2015-0049]*. This potential impact to peak hour demand and customer growth forecasts have not been incorporated in this Asset Management Plan due to the current uncertainty. Any outcomes resulting from the IRP study and advancements in the data collection and resultant strategies will be factored into future Asset Management Plans.

Table 1.10-4: Solution Planning Assumptions

ASSUMPTION	BASIS FOR ASSUMPTION
Budgeting and forecast is determined through the solution planning process.	Estimates are determined considering region and work type to accurately forecast. Appropriate project planning processes are followed.

2 Introduction

2.1 PURPOSE OF THE ASSET MANAGEMENT PLAN

EGD is comprised primarily of natural gas utility assets and operations that serve over 2.1 million residential, commercial, and industrial customers in Central and Eastern Ontario. The management of these assets is important for the safe and reliable delivery of natural gas to customers. Asset management at EGD ensures that value is realized through its assets while managing risk and opportunity.

The purpose of this Asset Management Plan is to outline:

- Policy and strategies for achieving effective asset management for all utility assets within EGD's regulated operations
- Process and governance for asset management
- Asset class objectives and life cycle management policies
- Asset inventory, condition methodology, condition findings, risks, opportunities, and strategies
- Optimized 10-year capital plan required to manage assets from 2019-2028

This Asset Management Plan aligns with ISO5500X, the International Standard for Asset Management, and addresses recommendations from the Ontario Energy Board (OEB) *Decision with Reasons [EB-2012-0459]*. This Asset Management Plan is intended to meet the OEB's expectations as set out in the *Handbook for Utility Rate Applications* and the *Filing Requirements for Natural Gas Rate Applications*.

2.2 COMPANY PURPOSE, VISION, VALUES, AND STRATEGIC PRIORITIES

*"Our **Purpose**, **Vision** and **Values** are core elements of the Enbridge story. Together, they unify and guide our organization and help our employees and others who work with us understand who we are, what we stand for, and why we exist. Each of our actions, decisions and interactions with people, inside and outside of the Company, express who we are and what we stand for, and influence how we are perceived. Together, we help fuel quality of life for millions of people in North America." [2018 ELink, Who We Are]*

Asset management supports the Company's Purpose, Vision, and Values by improving the Company's ability to operate safely and reliably, ultimately maintaining the satisfaction of our customers and other stakeholders. Asset management provides the necessary structure to make informed asset decisions and execute the resultant actions. In this regard, it is imperative that the framework of asset management at the Company is aligned with enterprise strategic priorities.

2.2.1 Purpose

"We fuel people's quality of life."

Our Purpose reminds people of the essential quality of life that Enbridge provides. It communicates why we exist and the contribution we make to people's lives." [2018 ELink, Who We Are]

The Company delivers energy where and when it is needed and does so reliably, efficiently, and always with the safety of employees, the public, and the environment in mind. Asset management at EGD ensures these elements of quality are embedded within EGD's decision-making framework.

2.2.2 Vision

*"Our vision is **to be the leading energy delivery company in North America**. We play a critical role in enabling the economic well-being and quality of life of North Americans, who depend on access to affordable and plentiful energy – because Life Takes Energy." [2017 Enbridge Inc. Annual Report]*

The Company demonstrates leadership in safety, environmental stewardship, customer service, its people, community investment, and shareholder value. Asset management ensures asset-value is realized by making optimal, transparent, and defendable decisions that ultimately provide value to its customers and shareholders and exemplify leadership among North American energy delivery companies.

2.2.3 Values

Enbridge continues to build on its foundation of operating excellence by adhering to a strong set of core values – *Integrity*, *Safety*, and *Respect* – in support of its communities, the environment, and its people. Asset management helps maintain the integrity of assets to ensure the Enbridge operates safely and reliably, respecting customers and stakeholders.

2.2.4 Strategic Priorities

Enbridge's Enterprise Strategic Priorities (**Figure 2.2-1)** are defined to enable the company to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities and contribute to Enbridge's success. They support the purpose of fueling people's quality of life, while maintaining the foundation of the business, and positioning the company for future growth.

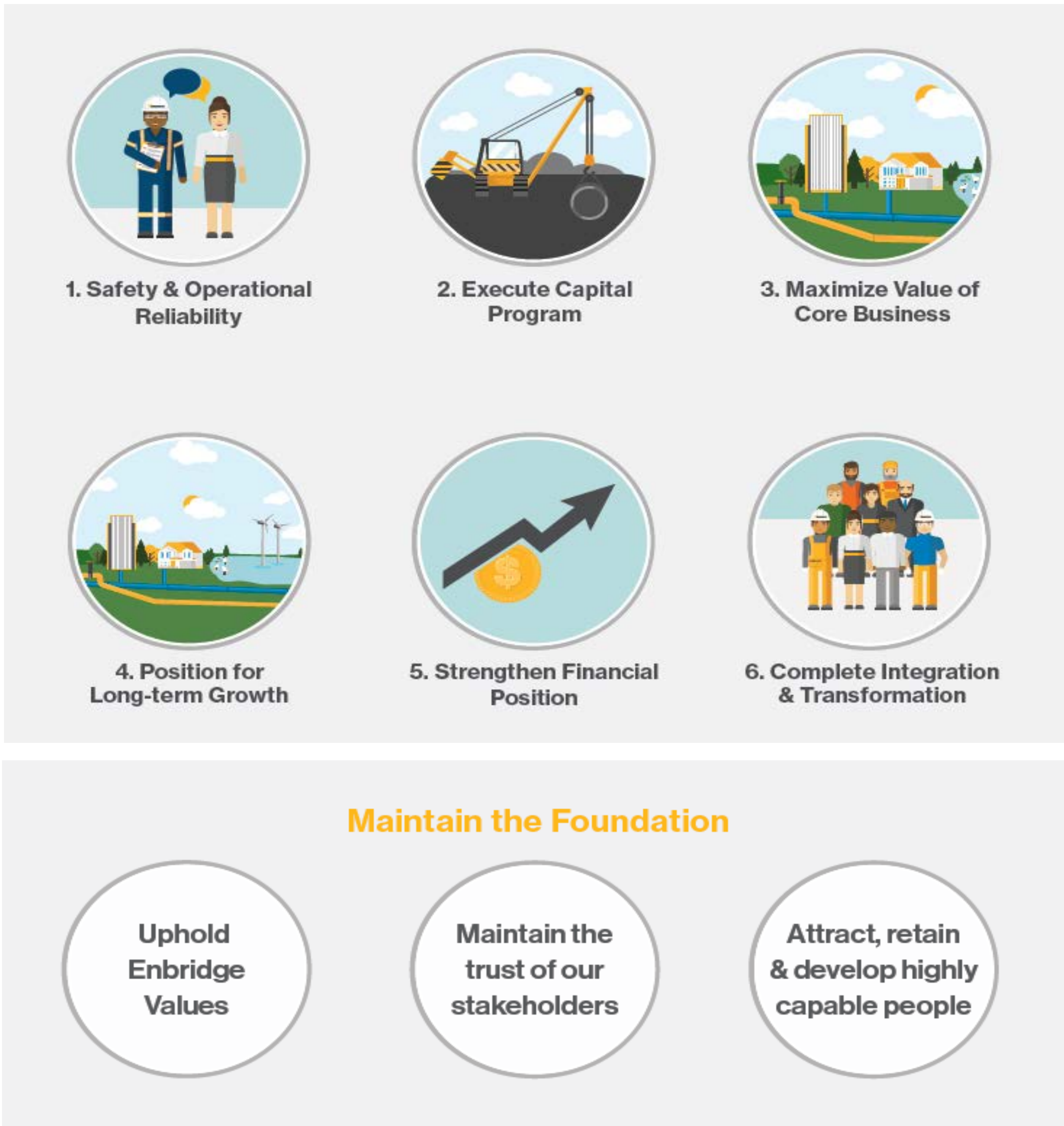


Figure 2.2-1: Enbridge Enterprise Strategic Priorities

2.3 ORGANIZATION AND STRUCTURE

Enbridge carries out its activities through three core business units: Liquids Pipelines, Gas Transmission and Midstream (GTM), and Utilities (**Figure 2.3-1**). The Utilities business includes EGD, UGL, Power Operations and other affiliate companies (Enbridge Gas New Brunswick Inc., Gazifère Inc., Niagara Gas Transmission Limited, 2193914 Canada Limited, and St. Lawrence Gas Company Inc.).

In addition, Enbridge's Central Functions teams (Finance, Legal Services, Human Resources, Technology and Information Services, Supply Chain Management, Public Affairs and Communications, and Real Estate and Workplace Solutions) enable business units to achieve their strategic goals.

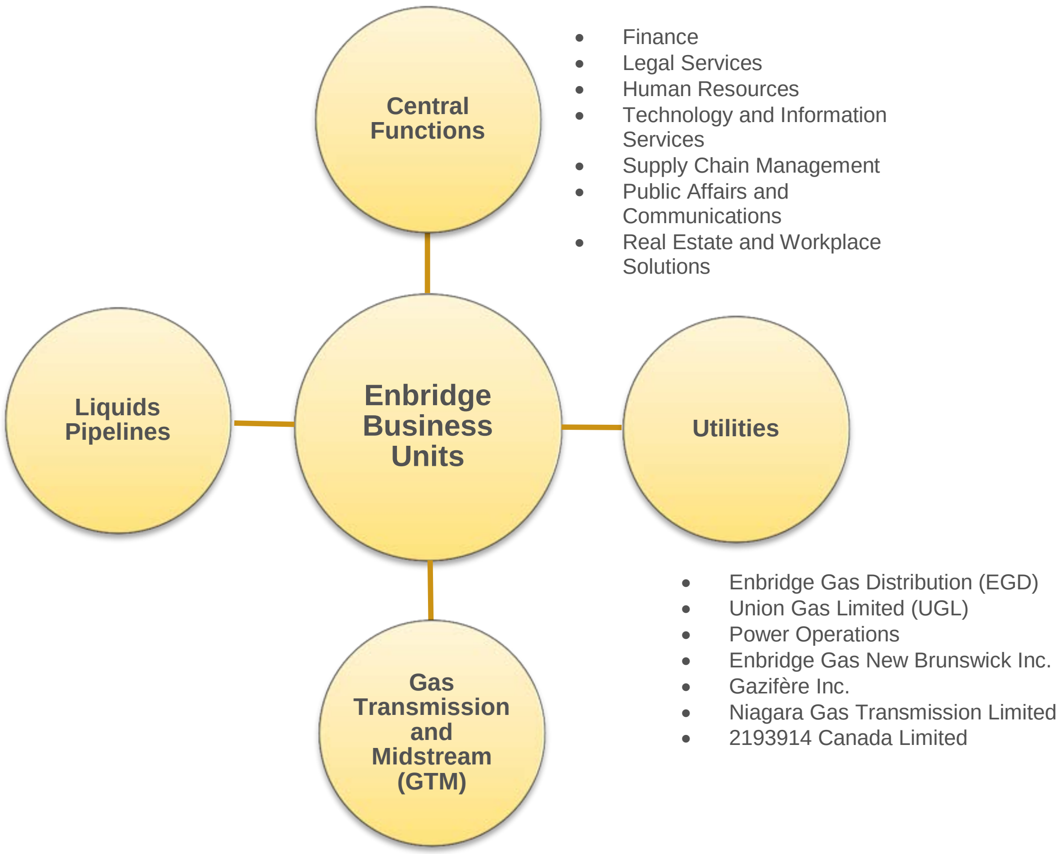


Figure 2.3-1: Enbridge Business Units

EGD within Ontario is regulated by the OEB. This Asset Management Plan outlines the management of EGD's regulated assets in Ontario.

2.3.1 Enbridge Gas Distribution

EGD serves over 2.1 million residential, commercial, and industrial customers in Central and Eastern Ontario.

EGD's franchise area is divided into eight administrative areas (Areas 10, 20, 30, 40, 50, 60, 70, and 80) as shown in **Figure 2.3-2**. All of EGD's gas distribution assets reside in these areas:

- Area 10 covers the City of Toronto
- Areas 20, 30, 40 and 50 cover the remainder of the Greater Toronto Area (GTA) and surrounding region
- Area 60 covers Ottawa and the surrounding region
- Area 70 covers Gas Storage operations in southwestern Ontario (not shown)
- Area 80 covers the Niagara Region

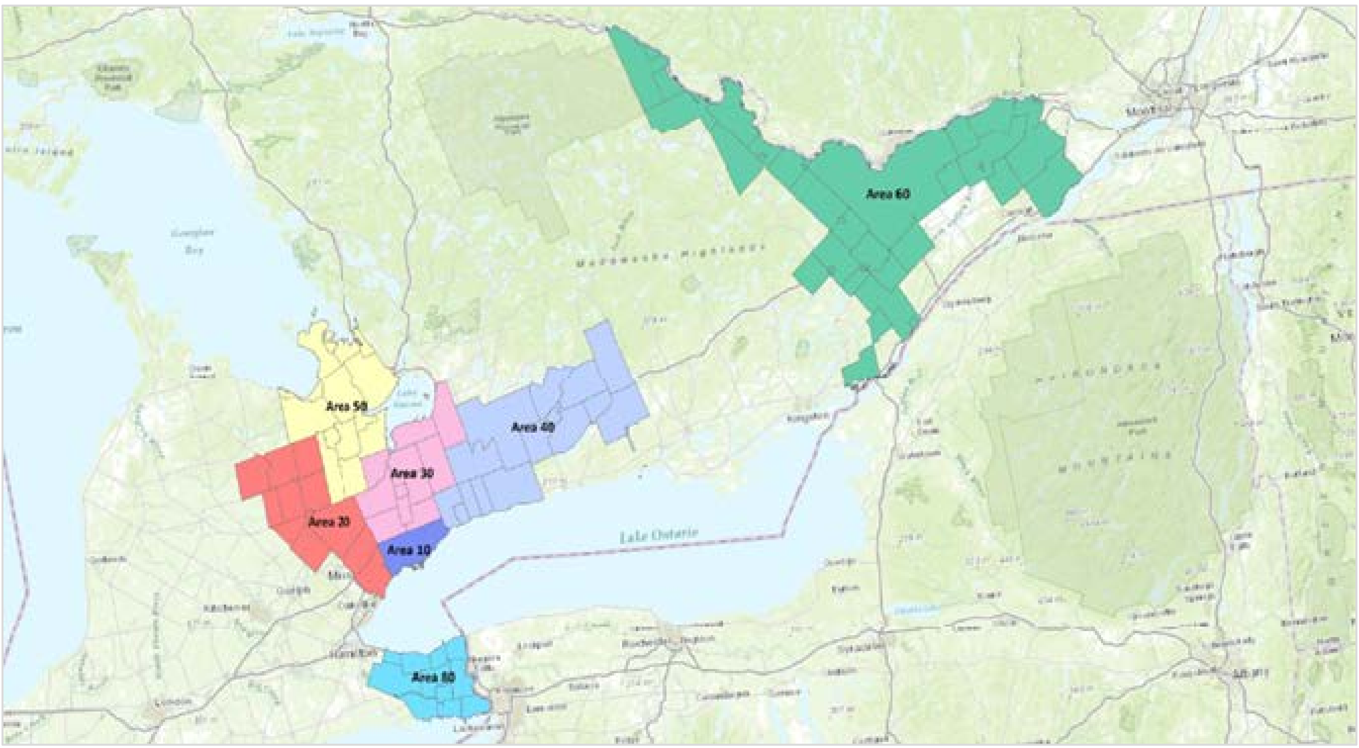


Figure 2.3-2: EGD Administrative Areas

2.4 STAKEHOLDER COMMITMENT

EGD is committed to its customers, regulatory bodies, and other stakeholders. EGD's responsibilities include:

- Servicing and safely delivering natural gas to customers
- Maintaining network and system reliability
- Responding to gas-related emergencies
- Reading and testing meters
- Meeting the expectations and requirements of its regulators, the OEB and the Technical Standards & Safety Authority (TSSA)
- Managing cost, risk, and performance

EGD engages its stakeholders to maintain awareness and drive involvement at the inception of new projects and throughout regular operations.

Understanding stakeholders and their concerns is critical to making good business decisions and mitigating risk. There is a direct link between EGD's ability to respond effectively to public concerns, the ability to manage costs, and regulatory approval timelines. EGD regularly engages with the following stakeholders:

- Associations and civil society groups
- Communities
- Customers
- Employees, contractors, unions, boards of directors
- Environmental and other non-governmental organizations
- Governments and government regulatory bodies
- Indigenous peoples
- Individuals and organizations with whom we work to prepare for and respond to emergencies
- Investors
- Landowners
- Local businesses and industry
- Media
- Regulators
- Right-of-way communities
- Suppliers

As a reflection of its stakeholder engagement, EGD's core goals are employee and public safety, compliance, financial performance, operational reliability, environmental sustainability, and customer satisfaction. These goals play a key role during the evaluation of cost, risk, and performance related to asset investment decisions.

Asset management at EGD and this Asset Management Plan are a direct demonstration of the company's commitment to its stakeholders to ensure asset value is realized and optimal decisions are made based on risk and opportunity.

2.4.1 Customer Engagement Results

As per the Rate Handbook released by the OEB on October 13, 2016, utilities are expected to develop a genuine understanding of their customers' interests and preferences, and to incorporate these findings into their Utility System Plan (USP). EGD's Asset Management Plan is a component of the USP. The Rate Handbook directs that *"Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and providing services in a manner which is responsive to customer preferences. Customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs."*

To this end, EGD commissioned a third-party global market and research specialist, Ipsos Public Affairs, to conduct a customer engagement survey. This survey provides insight into the satisfaction, needs, and preferences of EGD's customers with respect to future initiatives and investment plans. This research is intended to complement EGD's regular customer satisfaction surveys (which are used more frequently to monitor the perception and trust of customers as it relates to the interactions and dealings with the company) and more specifically focuses on:

- Overall customer satisfaction
- Satisfaction with safety, reliability, customer service, and value
- Experience with service issues and natural gas outages
- Customer preferences for improved services
- Willingness to pay for maintaining or improving service
- Awareness of GHG reduction initiatives, renewable natural gas, and conservation programs

- Willingness to pay for investments into renewable natural gas
- Preferences for investment in conservation and into renewable energy sources
- Willingness to pay for investments included in EGD's Asset Management Plan

The survey collects feedback from a multitude of different groups ranging from residential to large volume customers. The results are important inputs to EGD's investment planning activities and exemplify EGD's commitment to its customers.

The key themes formed by the responses are:

- Customers are satisfied with the reliability and the safe delivery of natural gas to their home or business and most feel that EGD should invest in maintaining current levels of reliability (with some responses indicating a preference to further improve on these areas).

- Customers are satisfied with the value they receive for the money they pay for their service and the majority found it acceptable to pay more on their bills over the next 5 years to cover the costs associated with aging infrastructure to maintain the current level of reliability and safety.

- Although customer knowledge varies on GHG reductions initiatives and on renewable natural gas, there is alignment with customers in each customer segment on the preference of EGD investing in renewable energy sources to reduce the overall network consumption and in conservation programs to help customers reduce their consumption.

These results demonstrate that customers are aligned with EGD's commitment to the safe, reliable, cost effective, and environmentally responsible provision of natural gas. It also informs and reinforces EGD's asset management decision-making framework. EGD's values and guiding policy statements, outlined in **Section 4.1.2**, align with the preferences of customers in the following ways:

- The core asset management goals are: employee and public safety, compliance, financial performance, operational reliability, environmental sustainability, and customer satisfaction.

- EGD is committed to prudent value-based decision-making for all asset-related investments on a holistic evaluation of cost, risk, and performance.

- EGD is committed to sustainable, lower-carbon initiatives and new energy solutions, as well as the incorporation of these strategies within asset management planning and investment decisions.

- EGD is committed to understanding and delivering value to its customers.

3 Asset Management Framework

3.1 ASSET MANAGEMENT IMPROVEMENTS

In 2013, EGD filed an Asset Management Plan with the OEB for the first time as part of its Custom IR filing *[EB-2012-0459]*. The plan covered 10 years, and provided a description of anticipated distribution asset-related requirements and the related capital investment to support customer additions, system reinforcements, asset relocations, and system integrity and reliability.

In response to the OEB's findings, EGD has advanced its asset management framework to facilitate and govern asset investment planning at the Company, and prepared an improved version of its Asset Management Plan.

In 2018, EGD submitted this prepared Asset Management Plan (2018-2027) in response to interrogatories during the MAADs and Rate-Setting Mechanism Applications *[EB-2017-0306/EB-2017-0307]*. The document incorporated recommendations from the *OEB Decisions with Reasons* in the Custom IR case, Section 2.2.6.1 from the *Filing Requirements for Natural Gas Rate Applications*, and asset management best practices based on ISO5500X. Specific improvements included:

- The inclusion of all OEB-regulated assets in the Asset Management Plan
- The development of a multidisciplinary, systematic approach to asset planning
- The use of condition assessment, risk evaluation, and optimization for asset planning
- The direct linkage of the capital planning to the Asset Management Plan
- The incorporation of third-party assessments on EGD's asset management process and planning

EGD continues to evolve its asset management practices to produce a robust Asset Management Plan. As a result, this Asset Management Plan (2019-2028) includes the following changes from 2018-2027:

- **Alignment with Enbridge Inc.'s 2018 Enterprise Strategic Priorities**

  Enbridge Inc. published a revised Strategic Plan in 2018. The alignment of EGD's Asset Management Policy, Asset Management Strategies and dimensions of risk have been adjusted accordingly, found in **Section 4.1.4**.

- **Consideration of Integrated Resource Planning (IRP)**

  In response to the OEB's direction *[EB-2015-0049]* to submit a plan to incorporate DSM into infrastructure planning activities, EGD has documented its Transition Plan and summarized this in **Section 3.5**. IRP will continue to be monitored as part of EGD's Asset Management Plan to ensure advancements made in the data collection and resultant strategies are acknowledged and incorporated during asset investment planning. (**Section 3.5**).

- **Evolution of asset condition and strategies**

  The structure of Customers & Assets (**Section 5**) has been updated. Inventory, condition, risk/opportunity and strategies have been updated to reflect the current understanding of assets. Specific project and program information is provided in the Appendix to support each asset class's strategic plans. The key changes are:

  - The inclusion of EGD's Business Development's lower-carbon strategies, such as Renewable Natural Gas (RNG), DSM, Geothermal, and Power-to-Gas, with no capital requirements included in this Asset Management Plan at this time (with the exception of Hydrogen Blending for Power-to-Gas). These initiatives are under various stages of regulatory review, and could be incorporated into future iterations of the Asset Management Plan.
  - Updates to the strategy on Storage Renewal for the Storage asset class to ensure comprehensive assessment of all solution options.
  - Updates to the strategy for distribution steel mains of the Pipe asset class to reflect current condition and risk information.

- **Exclusion of Projects Under Development**

  Projects where solution scopes are still under development are not currently included in EGD's 10 year portfolio of spend. These developing projects (six in total) are identified in **Section 6.4**, summing to a total of up to $470M and will be incorporated once solution timing and scopes are confirmed.

Moving forward, with the recent decision to amalgamate the two utilities, EGD and UGL will work towards consolidating its Asset Management framework and plans.

3.2 STRUCTURE AND SCOPE OF EGD'S ASSET MANAGEMENT PLAN

Figure 3.2-1 is an illustration of EGD's Asset Management Plan structure.

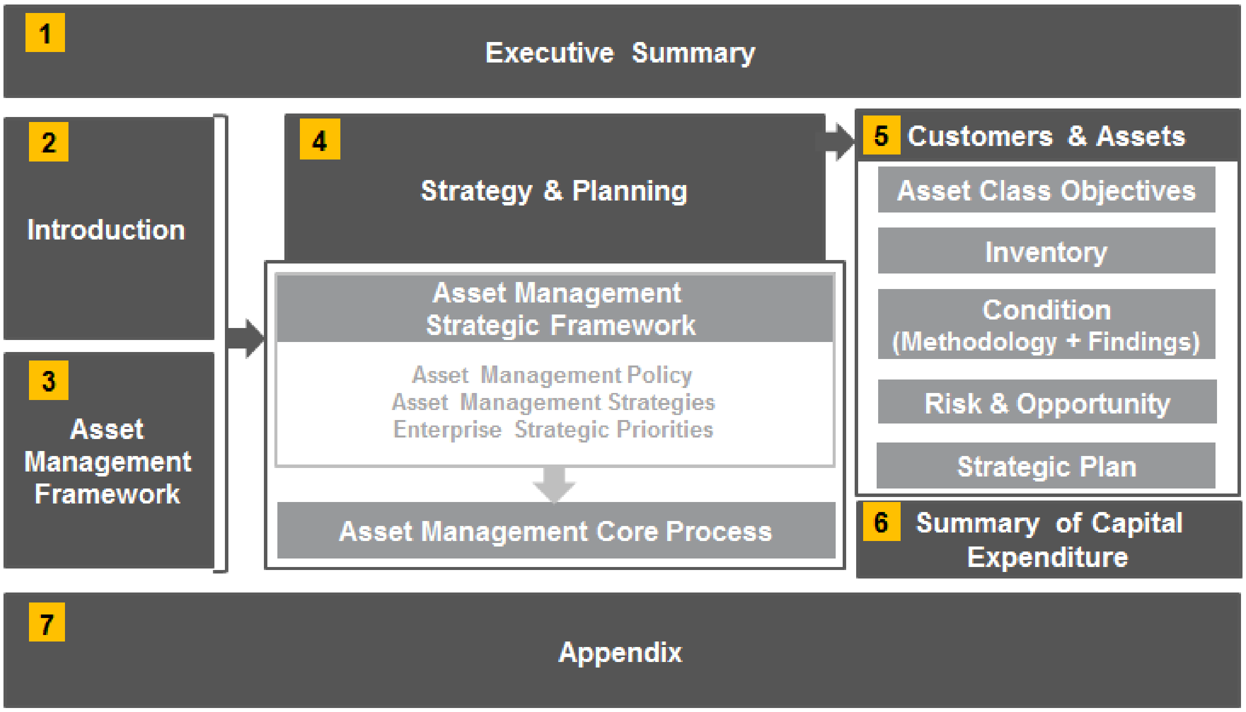


Figure 3.2-1: EGD's Asset Management Plan Structure

Introduction (Section 2) and Asset Management Framework (Section 3): This plan starts with an introduction of the Company. It also highlights EGD's stakeholder commitment, improvements from previous EGD Asset Management Plans, the change management strategy, the structure of the document, and a summary of EGD's alignment to ISO5500X.

Strategy and Planning (Section 4): The Strategy and Planning section details the alignment of asset management at EGD with the Enterprise Strategic Priorities and includes EGD's Asset Management Policy, Asset Management Strategies, and the Asset Management Core Process.

Customers and Assets (Section 5): The Customers and Assets section details the following for each asset class:

- Asset class objectives and life cycle policies
- EGD's customers and the customer growth projections
- Asset inventory
- Asset condition and life cycle strategies for managing assets
- Strategic plans to meet life cycle strategies

Summary of Capital Expenditure (Section 6): This section summarizes the 10-year capital investment plan for EGD, outlines the optimization process and highlights key assumptions used for Section 5 and 6.

Appendix (Section 7): The appendix presents supporting information for the Asset Management Plan.

3.3 INDEPENDENT REVIEW OF ASSET MANAGEMENT PRACTICES

An independent assessment of EGD's 2018-2027 Asset Management Plan was conducted by KPMG, and a final report on observations, leading practices, gaps, and opportunities was provided to EGD in September 2017 [*Enbridge Gas Distribution: Asset Management Assessment by KPMG*].

The KPMG third-party assessment used ISO5500X as the standard framework for analysis and evaluated EGD in the areas outlined in **Table 3.3-1** .

Table 3.3-1:: Evaluated ISO5500X Framework Components

ISO SECTION	SUB-CATEGORY
4.0 Context of the Organization	4.1 Understanding the organization and its context
	4.2 Understanding the needs and expectations of stakeholders
	4.3 Determining scope of asset management system
	4.4 Asset management system
5.0 Leadership	5.1 Leadership and commitment
	5.2 Policy
	5.3 Organizational roles, responsibilities, and authorities
6.0 Planning	6.1 Actions to address risks and opportunities for the asset management system
	6.2 Asset management objectives and planning to achieve them
7.0 Support	7.1 Resources
	7.2 Competence
	7.3 Awareness
	7.4 Communications
	7.5 Information management
	7.6 Documented information
8.0 Operation	8.1 Operational planning and control
	8.2 Management of change
	8.3 Outsourcing
9.0 Performance Evaluation	9.1 Monitoring measurement, analysis, and evaluation
	9.2 Internal audit
	9.3 Management review
10.0 Continuous Improvement	10.1 Nonconformity and corrective action
	10.2 Preventative action
	10.3 Continuous improvement

The maturity of these areas was evaluated using a standardized rating scale described in **Table 3.3-2**.

Table 3.3-2: Maturity Level Definitions

Maturity Level				
0 (Aware)	1 (Reactive)	2 (Proactive)	3 (Managed)	4 (Leading Practice)
The organization has no / inadequate process(es) in place for asset management.	The organization has identified the need for asset management, and there is evidence of intent to progress it. Policies may be in place, that need updating	The organization has developed an action plan to systematically and consistently achieve asset management requirements, and can demonstrate that these are being progressed with credible and resourced plans in place. There is documentation in place for major processes but no set plans for continual improvement and change management.	The organization has a well-documented asset management program set to systematically and consistently achieve its goals. Documentation outlines an approved process for change management, updating documents and processes, and continual improvement.	The organization's process(es) surpass the standard required to comply with ISO55000x requirements.

Based on KPMG's assessment, EGD's Asset Management Program is operating primarily within the *Proactive* and *Managed* levels of maturity, as seen in **Figure 3.3-1**.

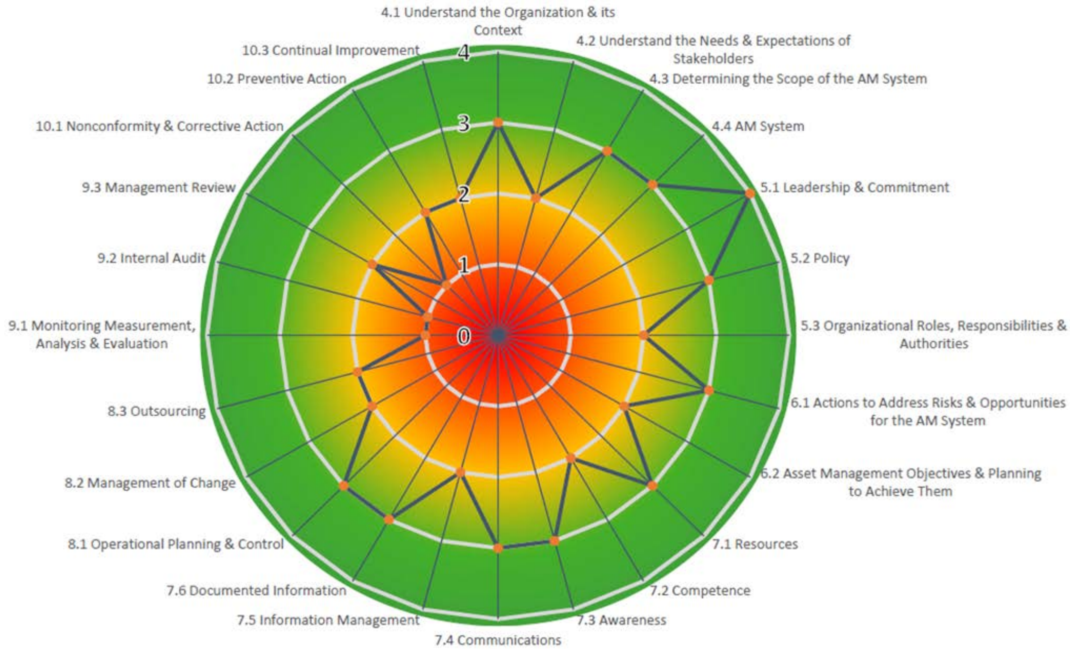


Figure 3.3-1: EGD's ISO5500X Maturity Assessment – Current (Performed by KPMG)

EGD continues to work on incorporating the recommendations from KPMG's assessment to further evolve in asset management best practices and increase its asset management maturity level to the aspired state illustrated in **Figure 3.3-2**.

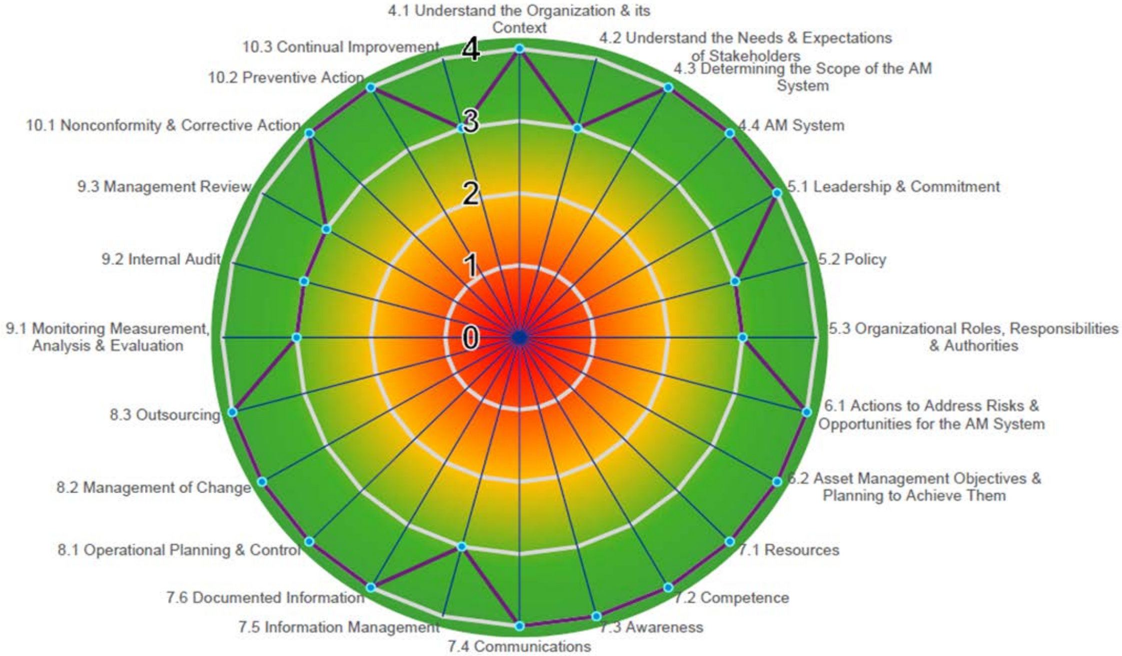


Figure 3.3-2: EGD's ISO5500X Maturity Assessment – Evolved (Performed by KPMG)

3.4 ORGANIZATIONAL CHANGE MANAGEMENT

Asset management requires comprehensive change management to ensure successful adoption and implementation. For the implementation and operational sustainment of asset management practices, EGD follows an industry best practice, three-tiered change management approach: Preparation, Management, and Reinforcement (**Figure 3.4-1**). This approach encompasses a tactical ADKAR model (Awareness, Desire, Knowledge, Ability, and Reinforcement).

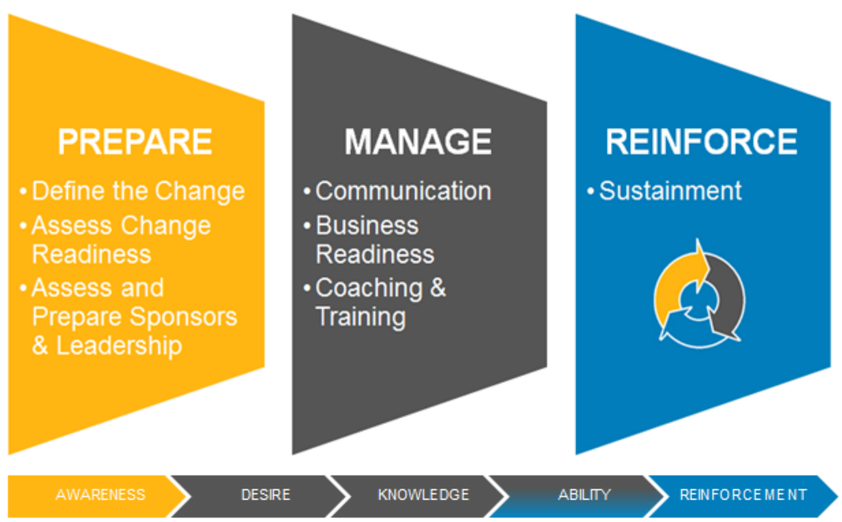


Figure 3.4-1: Change Management Approach

For change to succeed, employees need to have **awareness** of why change is needed. Awareness of asset management related changes is maintained through ongoing communication, coaching and reinforcement.

Employee **desire** to participate and support change is a key element of adopting asset management. EGD builds this desire through engagement, communication, active and visible leadership, training, and having clear objectives and metrics.

Knowledge is built through training (classroom, online sessions, and workshops), communication, engaged leadership, and peer-to-peer learning. Classroom and online training are used to help employees gain the knowledge and **ability** to implement required skills and behaviors. Change agents are leveraged across EGD to support their peers in adapting to and realizing the benefits of asset management changes.

To ensure the successful adoption and sustainment of asset management, **reinforcement** of changes and why they are required is continuous. A Plan-Do-Check-Act approach is used to support this reinforcement.

EGD conducted an Organizational Change Management initiative in 2017 to develop a change plan for 2018 and onwards to support Asset Management principles and practices. The approach is illustrated in **Figure 3.4-2**. Through this activity, the following six focus areas were identified for change management:

- Asset Management Framework
- Risk Management
- Measurement
- Data Management
- Tools
- Roles

EGD is currently executing the detailed change plan in consideration of stakeholder input and potential change impact - implementing this plan will support asset management best practices.

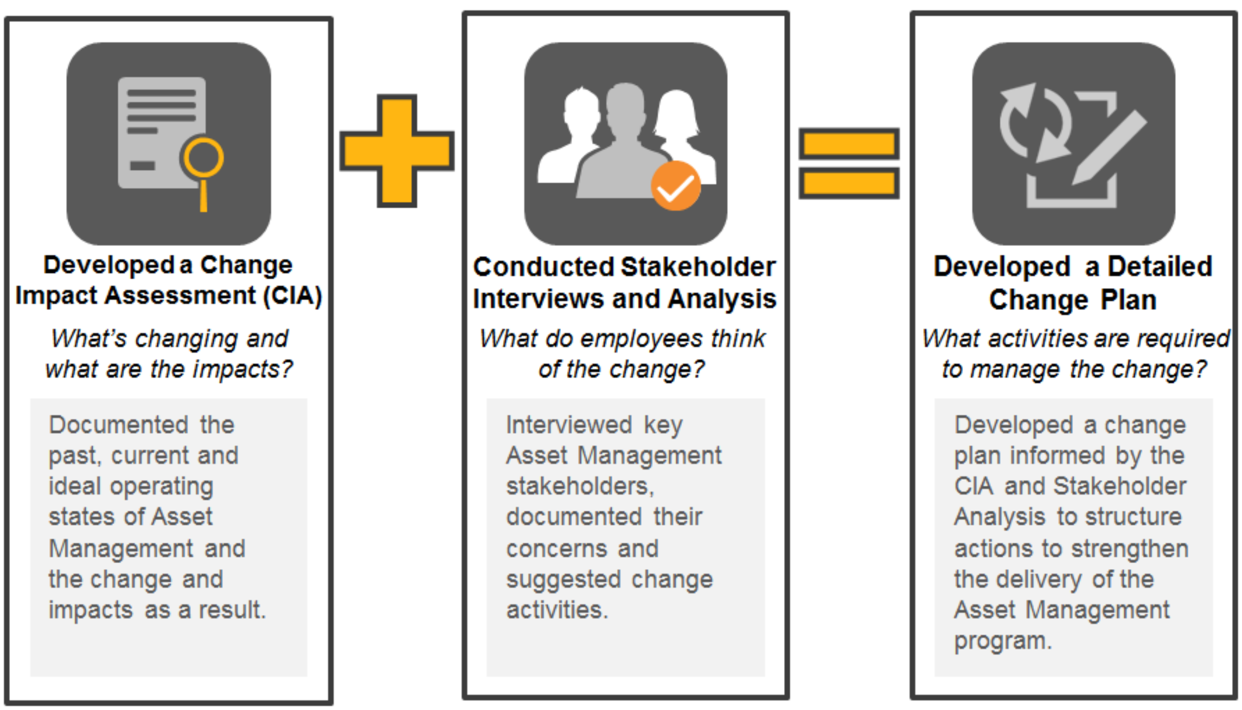


Figure 3.4-2: EGD's Change Management Approach

3.5 INTEGRATED RESOURCE PLANNING (IRP)

Consumers have the right to safe and reliable service, as well as the right to access available energy conservation programs.[5] In response to the OEB's direction *[EB-2015-0049]*, EGD has filed a Transition Plan on how it anticipates integrating the supply and demand side processes. The Transition Plan lays the groundwork for a pathway to consider Integrated Resource Planning (IRP) over the coming years. This plan will aid in the coordination between distribution planning processes and analysis, and low carbon alternatives, including energy efficiency. IRP at EGD refers to a multi-faceted planning process that includes the identification, preparation, and evaluation of all realistic supply-side and demand-side options to determine the least cost and lowest risk approach in addressing transmission and distribution infrastructure requirements. The IRP process could include:

- A review of a variety of different lower-carbon options such as energy efficiency to defer existing regional and local infrastructure
- The impact of net-zero ready subdivisions and Behind-the-Meter solutions
- Distributed energy resources (i.e., renewable natural gas)
- The interplay of these various energy options and the subsequent impact on infrastructure to meet system demand.

The primary goal of infrastructure planning is to ensure that the utility's infrastructure is sufficiently robust to provide reliable and safe natural gas service that meets the designed condition peak hour requirement forecast (see **Section 5.1.2**). The impact of broad-based DSM programs on infrastructure investment is inherently captured in the infrastructure planning process. Historical gas throughput is used as a base to predict future consumption and is updated each year. These historical forecasts include changes in gas usage resulting from implementation of DSM measures, as well as other conservation factors such as improved building codes and higher energy efficiency standards for natural gas equipment. The infrastructure plans do not explicitly factor in future projections of DSM program effects on peak day or peak hour demand as they are not known and therefore not certain.

As EGD's IRP and DSM programs evolve, there will be increased clarity around the subsequent impact of these initiatives on peak period demand, further informing infrastructure planning and forecasting processes. IRP will continue to be monitored as part of EGD's Asset Management Plan to ensure advancements made are acknowledged and incorporated during asset investment planning.

[5] https://www.oeb.ca/consumer-protection/how-we-protect-consumers/consumer-charter

4 Strategy and Planning

Asset management at EGD is based on Deloitte's Value-Based Asset Management Model (**Figure 4.0-1**), which provides the framework for EGD's Asset Management Program.

This model integrates all asset management activities into a four-step management system of Plan-Do-Check-Act while supporting the implementation of Asset Management Strategies, described in **Section 4.1.3**. Each chevron of the wheel represents a key component in the asset management process:

- Determining EGD's Strategic Framework
- Identifying risks, opportunities, and their resultant investment options
- Outlining how optimized decisions are made for the strategic investment plan and annual portfolio plan (i.e., the Asset Management Plan)
- Explaining how asset management performance is measured
- Outlining the tools, data, and analytics that support these activities

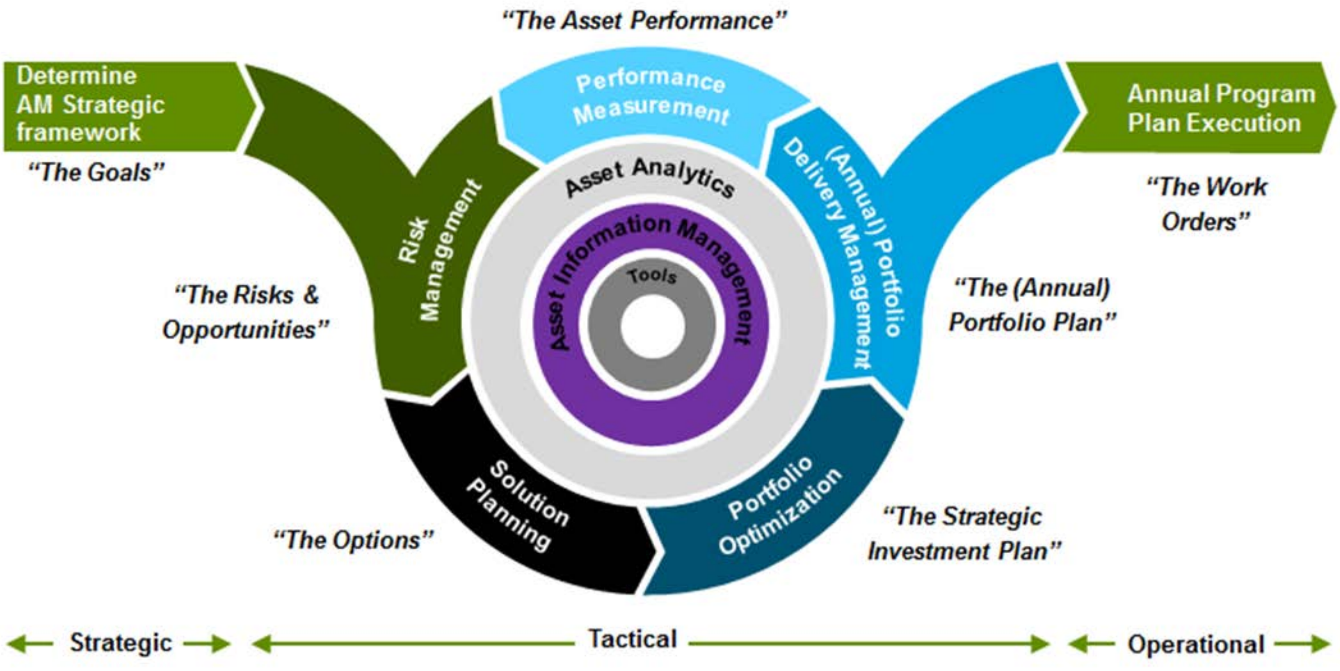


Figure 4.0-1: Value-Based Asset Management Model

4.1 DETERMINING THE ASSET MANAGEMENT STRATEGIC FRAMEWORK

EGD's asset management strategic framework includes Enbridge's Enterprise Strategic Priorities, the EGD Asset Management Policy, and Asset Management Strategies (**Figure 4.1-1**). This strategic framework provides a foundation that supports the Asset Management Core Process (**Section 4.2**).

Figure 4.1-1: EGD's Asset Management Strategic Framework

The Enbridge Enterprise Strategic Priorities (**Section 2.2.4**) sets the foundation for all company-wide operations and initiatives. The Asset Management Policy (**Section 4.1.2**) translates the Enterprise Strategic Priorities into the application of asset management at EGD and outlines the high-level goals and principles used to manage assets. Asset Management Strategies (**Section 4.1.3**) supports the policy, and outlines the methods employed for asset management success. Lastly, the Asset Management Core Process (**Section 4.2**) outlines how the identified strategies will be executed.

The alignment of Asset Management Strategies to the Enterprise Strategic Priorities is summarized in **Section 4.1.4**.

4.1.1 Enbridge Enterprise Strategic Priorities

The Enbridge Enterprise Strategic Priorities (see **Figure 2.2-1**) are defined to enable the enterprise to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities and contribute to Enbridge's success. They support the Company's purpose of fueling people's quality of life, while maintaining the foundation of the business, and positioning the Company for the future.

4.1.2 Asset Management Policy

VISION & MANDATE

Enbridge exists to fuel people's quality of life with a long-term vision to be the leading energy delivery company in North America. EGD is committed to the safe, reliable, cost effective and environmentally responsible provision of natural gas to its customers. At the core of this commitment is the effective stewardship of EGD's assets through governance, policy, and practices. EGD will apply leading asset management practices to effectively manage the life cycle of assets. Optimal value will be delivered to customers and stakeholders through a sustainable investment plan that balances cost, risk, and performance.

SCOPE

The Asset Management Program considers all OEB-regulated assets, which have been grouped into nine classes: Pipe, Stations, Storage, Customer Assets, Fleet & Equipment, Technology & Information Services (TIS), Real Estate & Workplace Services (REWS), Customer Growth, and Business Development. At this time, the Asset Management Program does not consider EGD's affiliates (Union Gas Limited, Enbridge Gas New Brunswick Inc., Gazifère Inc., Niagara Gas Transmission Limited, 2193914 Canada Limited, and St. Lawrence Gas Company Inc.). The Asset Management Program is a component of EGD's Integrated Management System, which provides a systematic approach to managing safety and reliability across the organization.

ASSET MANAGEMENT PROGRAM

Core asset management goals are employee and public safety, compliance, financial performance, operational reliability, environmental sustainability, and customer satisfaction. EGD employees must consider these goals when evaluating costs, risks, and performance related to asset investment decisions. Decisions are made through documented and transparent evaluation processes.

This policy applies throughout the asset life cycle and considers asset acquisition/creation, utilization, maintenance, and renewal/retirement. EGD will leverage an Asset Management Program based on the industry standard, ISO5500X, to demonstrate a systematic and coordinated approach to asset management activities. Consistent practices, processes and tools will be used to optimally and sustainably manage assets; this will be achieved by balancing cost, risk, and performance over asset life cycles while providing value to customers and stakeholders.

POLICY STATEMENTS

1. EGD will continuously improve its asset management approach, by driving innovation in the development of tools, processes, and solutions.
2. EGD is committed to prudent, value-based decision-making for all asset-related investments on a holistic evaluation of cost, risk, and performance.
3. EGD is committed to continual comprehensive condition assessment and risk review. EGD acknowledges that the understanding of the asset's life cycle is critical for decision-making and the safe and reliable delivery of natural gas.
4. EGD acknowledges that asset information is critical to transparent, knowledge-based decision-making. EGD shall work to ensure that its processes, systems, and controls collectively strive to deliver verifiable, traceable, complete, timely, accurate, and accessible asset information.
5. EGD is committed to sustainable/lower-carbon initiatives and new energy solutions, as well as the incorporation of these strategies within asset management planning and investment decisions.
6. EGD shall annually review and ratify its Asset Management Policy and Asset Management Plan with Senior Leadership.
7. EGD is committed to being in compliance with all applicable laws and regulations, industry codes, standards and internal policies.
8. EGD is committed to understanding and delivering value to its customers and stakeholders.

4.1.3 Asset Management Strategies

Six key strategies have been implemented to drive and support effective asset management at EGD:

Align Roles & Structure to Support Asset Management

- EGD's strategy of aligning its roles and structure to support asset management enables asset management principles to be understood, supported, and embedded in the culture at all levels of the company. To ensure effective and consistent asset management, the roles and structure of the organization have transformed to improve asset management function, leadership, and competence, ultimately improving EGD's decision-making ability for assets.

Produce and Evaluate Asset Information & Condition

- Asset data enables the business to evaluate existing asset information, determine patterns, and analyze predictions to inform life cycle management strategies. This strategy supports the people, process, and technology advances that enable the production and evaluation of asset information and condition.

Implement Life Cycle Management for Assets

- Life cycle policies for assets will drive consistent and holistic evaluation of investment opportunities. With clear objectives for the use and operation of assets, life cycle condition and costs can be examined to ensure that optimal asset value is attained over each asset's life.

Optimize Portfolio based on Asset Management Principles

- EGD's strategy is to use asset management principles to optimize and prioritize capital investments. Optimization based on risk/opportunity is an essential component of EGD's Asset Management Program.

Utilize Asset Management Tools that Evolve to Meet Business Needs

- EGD's strategy is to use asset management tools to provide the business with a platform to collect, manage, analyze, and optimize risks/opportunities and solutions. This stimulates and improves organizational knowledge and decision-making related to asset management.

Forecast Long-Term Asset Investment Plan

- EGD's strategy is to project a long-term Asset Investment Plan and a 10-year portfolio of work. Forecasting and understanding the long-term plan for its assets will benefit EGD with the creation of an optimized asset management plan that balances cost, risk, and performance while delivering value to its customers and stakeholders.

4.1.3.1 Align Roles and Structure to Support Asset Management

Nine asset classes at EGD (**Figure 4.1-2**) are used to categorize and manage investment decisions. Each asset class has its own ACM and ACD. Both roles are responsible for understanding the operational risks and opportunities associated with their respective asset class and managing the portfolio of work to ensure risk is managed to the lowest practicable level and optimum value is realized.

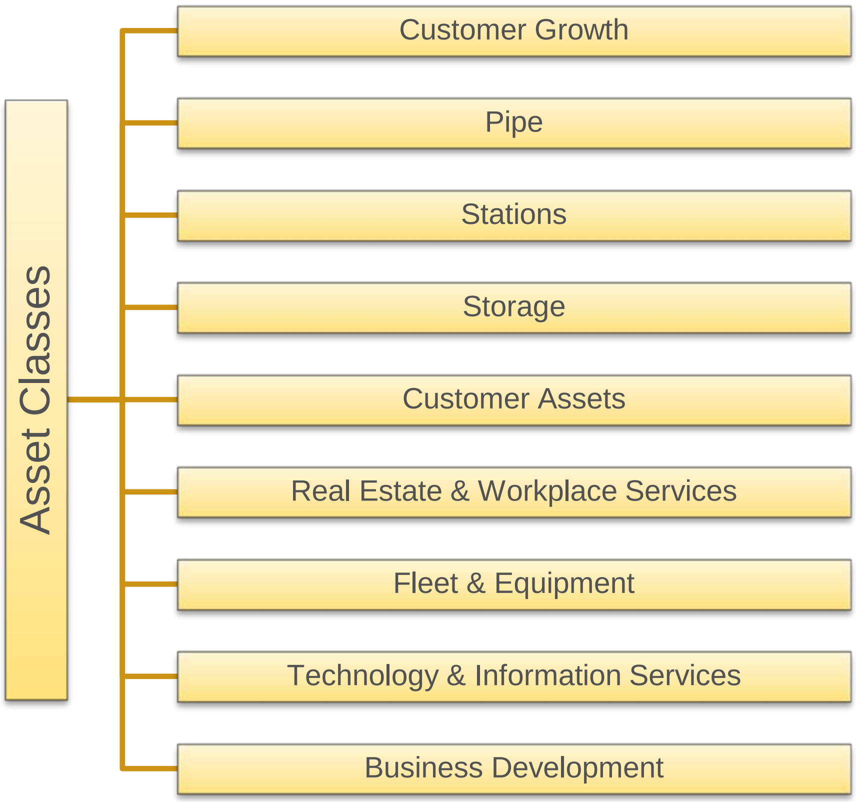


Figure 4.1-2: EGD Asset Classes

A matrix approach to asset management (**Figure 4.1-3**) enables the coordinated activity of defining an optimized and approved portfolio of work. This streamlines inputs from a diverse group of business stakeholders, while growing asset management practices across EGD.

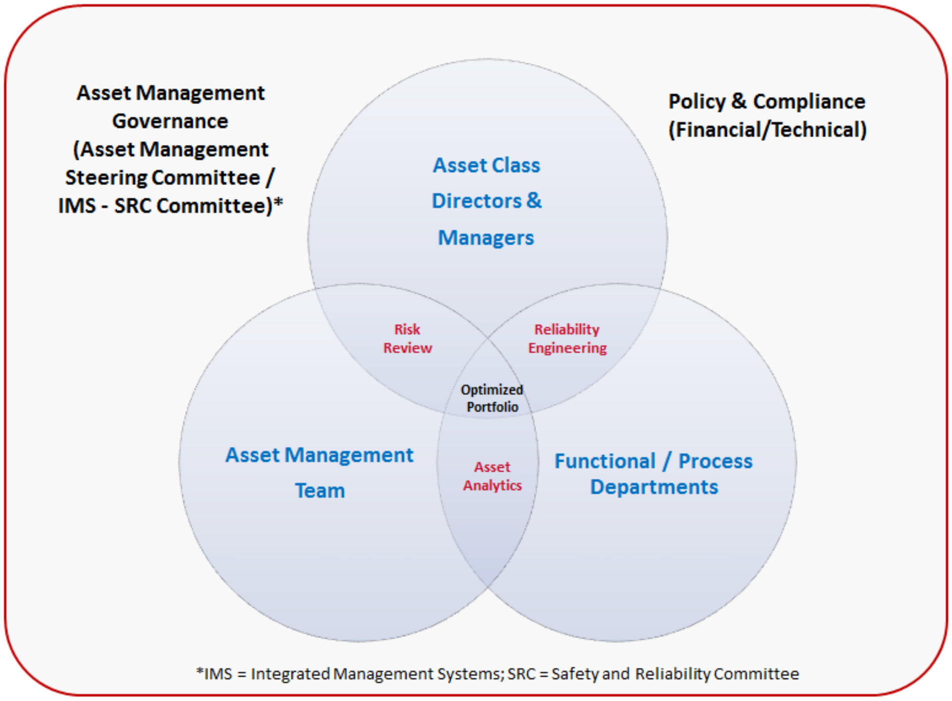


Figure 4.1-3: A Matrix Approach to Asset Management

The ACDs and ACMs perform the following:

- Understanding of asset condition and failure drivers
- Consolidation of emerging and existing risks and opportunities
- Preparation of business cases for risk review
- Proposal of potential solutions to identified risks
- Prioritization of solutions across the asset class
- Development of strategic plans for the asset class

The Asset Management Team establishes and governs the following:

- Asset management systems and methodology
- Risk management framework
- Risk analysis and review
- Asset management processes and tools
- Portfolio optimization
- Preparation and approval of the Asset Management Plan

The functional/process departments support asset management by providing:

- Engineering Assessments
- Integrity Assessments
- Financial support
- Regulatory support
- Tacit knowledge
- Planning and design
- Safety and incident information
- System Analysis Long Range Planning
- Project execution

Together, these roles provide the structured support for the Asset Management Core Process described in **Section 4.2** to ensure that capital expenditures are based on transparent, and defendable asset-based decisions.

4.1.3.2 Produce and Evaluate Asset Information and Condition

Asset data provides the foundation for asset investment planning, as seen in **Figure 4.1-4**. Asset analytics supports people, process, and technology advancements to enable defendable asset decisions. Asset analytics provides asset information that informs and supports asset health reviews, Engineering Reliability Assessments, risk and opportunity assessments, and asset replacement strategies. It also outlines the processes, governance, and systems required to ensure decisions are defendable and repeatable through the use of data that is fit for purpose.

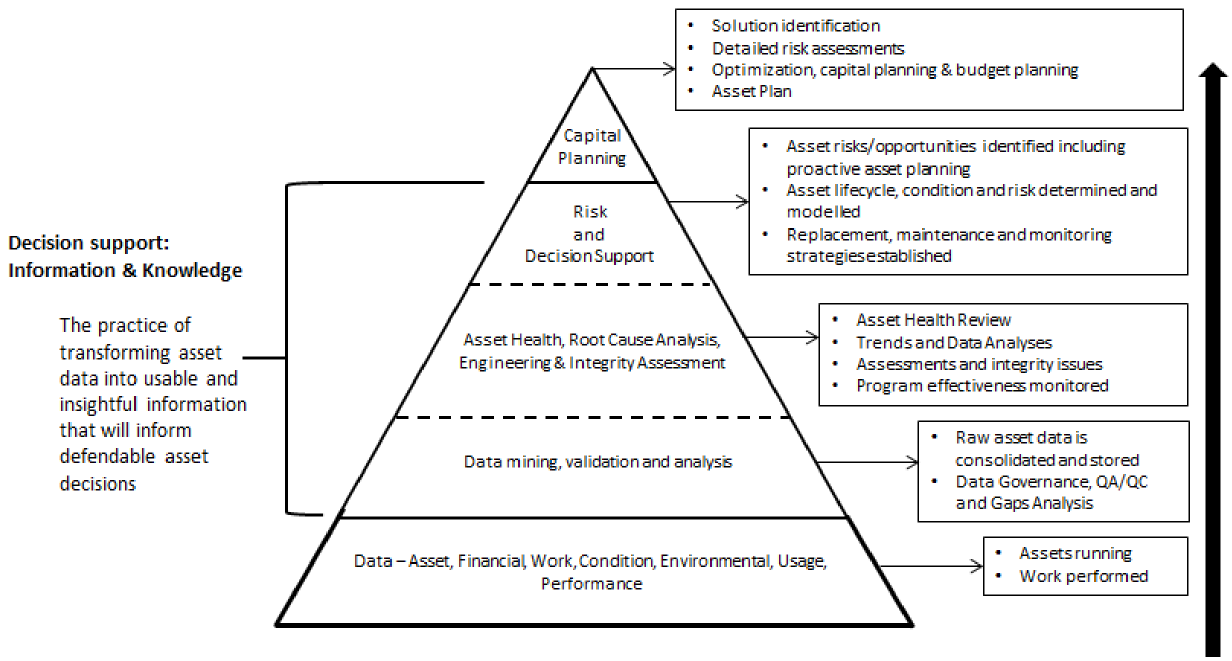


Figure 4.1-4: Asset Information and Support to Asset Investment Planning

Asset data enables the evaluation of existing assets, determines patterns, and identifies meaningful information to inform life cycle management strategies. A number of reports and tools are used to understand the condition of assets, as outlined in **Section 4.2.6.** With an understanding of asset failure modes and causes, these tools support the business to predict asset failure and optimize mitigation strategies.

4.1.3.3 Implement Life Cycle Management for Assets

Life cycle policies for assets will drive consistent and holistic evaluation of needs and opportunities. With clear objectives for the use and operation of assets, life cycle costs can be examined to ensure that optimal asset value is attained over the asset's life.

EGD has defined asset life cycle stages that are applied to all asset classes (**Figure 4.1-5**):

- Acquire/Create
- Utilize
- Maintain
- Renew/Retire

Using these stages, policies are developed for each asset class to support asset investment decisions.

Figure 4.1-5: Asset Life Cycle Stages

A number of inputs inform decision-making during an asset's life, as seen in **Figure 4.1-6.** Based on condition and risk, the plans for each asset class will align with their respective life cycle policies (detailed in **Section 5**).

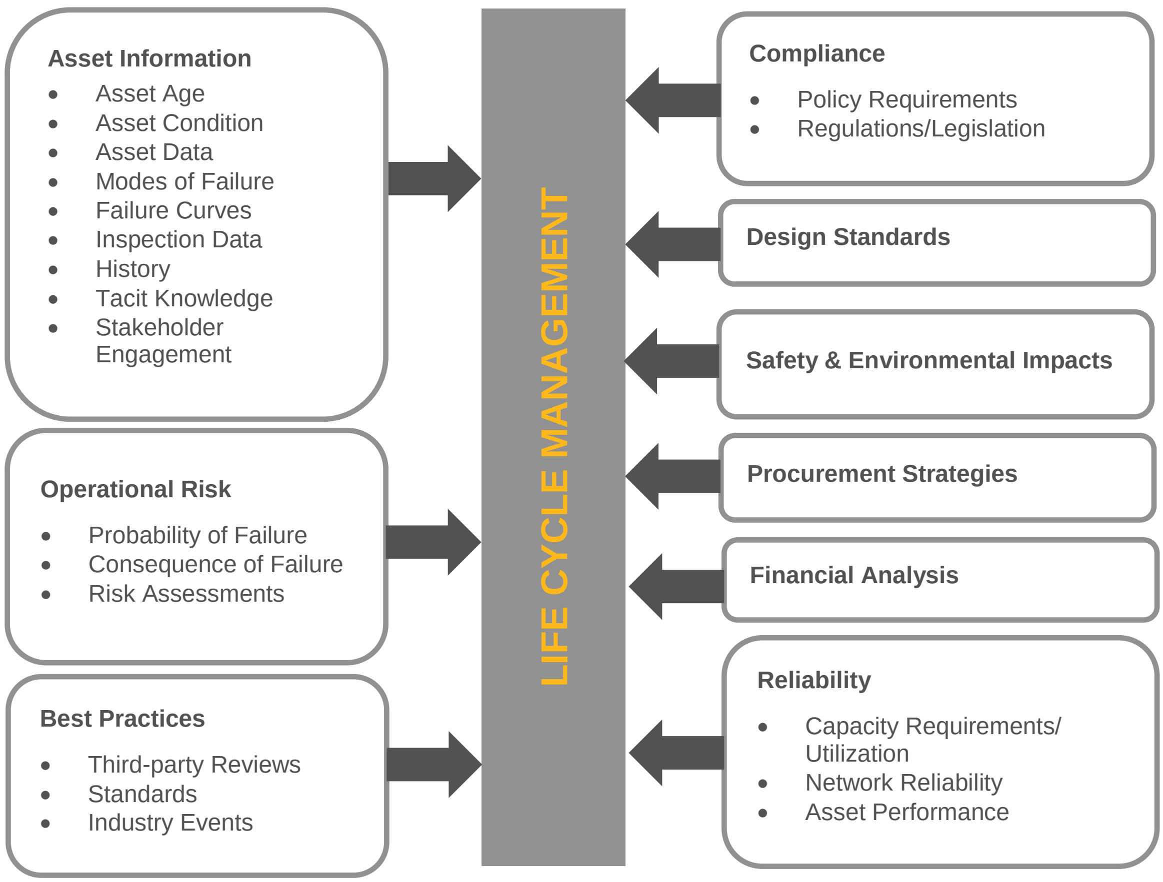


Figure 4.1-6: Life Cycle Management Inputs

4.1.3.4 Optimize Portfolio Based on Asset Management Principles

Risks and opportunities are defined as follows:

Table 4.1-1: Risk and Opportunity

TERM	EGD DESCRIPTION
Risk	A *negative* effect of uncertainty on the organization's objectives expressed as a combination of the likelihood and consequences of a potential event.
Opportunity	A *positive* effect of uncertainty on the organization's objectives expressed as a combination of the likelihood and consequences of a potential event.

Risks and opportunities are evaluated consistently across asset classes using a Quantitative Risk Assessment (QRA) process (**Figure 4.2-2**). QRAs are completed for risks/opportunities requiring a solution with a total net capital spend of greater than $100K and are not third-party relocation-driven. The QRA provides a best-quantified estimate of the level of risk posed by an issue, as well as the likely risk reductions of any mitigation options.

Risk assessments use the dimensions of *Safety, Financial*, and *Customer Satisfaction (CSAT)* to quantify risk. These are described in **Table 4.1-2**: EGD's risk dimensions and align to the Enterprise Strategic Priorities and the Asset Management Core Process. This alignment is also illustrated in **Figure 4.1-8**. The risk framework allows for the comparison of capital expenditures across asset classes, which in turn supports portfolio optimization. The consequence ratings that are used to assess the level of risk in each of these dimensions are presented in **Table 4.1-3**: EGD's Qualitative Consequence Ratings by Risk Dimension [a]**.**

Table 4.1-2: EGD's Risk Dimensions

DIMENSIONS OF RISK			DESCRIPTION AND ALIGNMENT WITH ENTERPRISE PRIORITIES AND ASSET MANAGEMENT POLICY
Safety	Health and Safety	Customer, Public, Employee	EGD is committed to the safe provision of natural gas. Safety is a corporate priority and is embedded as a goal within EGD's Asset Management Policy. This risk dimension quantifies the risk of varying degrees of harm to either EGD's customers, workers, or the public. In terms of health and safety impact, no differentiation is made between customers, members of the public, and workers (including contractors).
Financial	Physical Damage, Service Disruption, and Commodity Loss	Public, Commercial, Industrial property	EGD is committed to the responsible provision of natural gas. This risk dimension quantifies the financial risk of damaging third party property (public, commercial, or industrial) and evaluates the financial impact by the level of damage caused.
		Service Disruptions	EGD is committed to the reliable delivery of natural gas to its customers as well as the financial performance of the Company. This risk dimension values the sustainment of gas delivery to EGD's customers and quantifies the financial impact of service loss.
		Commodity Loss	EGD is committed to the responsible provision of natural gas. This risk dimension quantifies the financial risk to the Company associated with the loss of containment of natural gas as a commodity.
		Company Property	EGD is committed to the responsible provision of natural gas. This risk dimension quantifies the financial risk of damage to Company property.
	Regulatory	Technical Regulator (TSSA, MOL, etc.)	EGD is committed to being in compliance with all applicable laws and regulations, industry codes, standards, and policies. This risk dimension quantifies the financial risk to EGD associated with varying degrees of regulatory penalties.
	Economic Loss	Avoidable Cost	Financial performance is a priority for EGD and is embedded as a goal within EGD's Asset Management Policy. These risk dimension quantifies the level of financial risk that could be avoided by reducing cost and maintaining revenue.
		Lost Revenue	
Customer Satisfaction	Environment	Emissions (GHG)	EGD is committed to sustainable/lower-carbon initiatives. This risk dimension quantifies the increase or decrease in methane emissions.
		Rehabilitation	Environmental sustainability is a goal within EGD's Asset Management Policy. This risk dimension quantifies the size of the impact area and type of land that would require remediation.
	Operational	Operational Reliability	EGD is committed to the reliable provision of natural gas to its customers. Operational reliability is a priority for EGD and is embedded as a goal within EGD's Asset Management Policy. This risk dimension uses customer outage days to quantify level of severity.
	Reputational	Reputational	EGD is committed to understanding and delivering value to its customers and stakeholders. This risk dimension is in place to ensure that customer inconvenience and ultimately the trust of EGD's stakeholders is quantified.

Table 4.1-3: EGD's Qualitative Consequence Ratings by Risk Dimension [a]

	Impact Evaluation											
	Safety	Financial							CSAT			
	Health & Safety [b]	Physical Damage, Service Disruption and Commodity Loss					Economic Loss		Environmental		Operational	Reputational
	Customer/ Public/ Employee	Public, Commercial, Industrial property	Service Disruptions	Commodity Loss [d]	Company property	Technical Regulator (TSSA, MOL, etc.)	Avoidable Cost	Lost Revenue	Emissions (GHG) [c]	Rehabilitation	Operational Reliability	Reputational
Minor	Level 1 – Minor Hurt, short time period (hours to days to recovery)	Minor damage (front yard/drive)	Up to 10 customers	Gas loss related to normal operating condition PRV over 1 year	Repair of damaged service	Record/locate missing/inaccurate	*Values within this category are entered in relation to specific scenarios*	*Values within this category are entered in relation to specific scenarios*	Up to 10,000 SCM natural gas or equivalent	Remediate 100 m^2 agricultural or grass land	Up to 100 customer days lost or equivalent total customer bill increase	Minor future or existing customer inconvenience
Moderate	Level 2 - Moderate Hurt (week(s) to month(s) to recovery)	Repairable damage (4 hours to repair)	Up to 100 customers	Release associated with 2" IP/HP line over average isolation period	Repair of damaged main	Broken/omitted safety measure/near miss			Up to 100,000 SCM natural gas or equivalent	Remediate 100 m^2 wooded area	Up to 1,000 customer days lost or equivalent total customer bill increase	Measurable future or existing customer inconvenience
Serious	Level 3 - Severe Hurt (Long-term, life altering)	Significant damage/fire (no explosion, affecting portion of building)	Up to 1,000 customers	Release associated with 6" IP/HP line over average isolation period	Replace small station or boiler system at gate station	Incident, no injuries			Up to 1,000,000 SCM natural gas or equivalent	Remediate 100 m^2 wetland	Up to 10,000 customer days lost or equivalent total customer bill increase	Town/city coverage; significant future or existing customer inconvenience or impact to channel partner
Major	Level 4 - Single Fatality	Residential explosion or fire (entire building)	Up to 10,000 customers	Release associated with 12" XHP line over average isolation period	Replace major facility (district or feeder station)	Incident, single fatality			Up to 10,000,000 SCM natural gas or equivalent	Remediate 100 m^2 watercourse	Up to 100,000 customer days lost or equivalent total customer bill increase	National news/paper; costs associated with public relations campaign to restore lost public opinion and confidence (if applicable).
Critical	Level 5 - Multiple (10) Fatalities	Commercial or highly developed residential explosion or fire	Up to 100,000 customers	Average well blowout - controlled within two weeks	Replace critical facility (gate station)	Incident, multiple fatalities			Up to 100,000,000 SCM natural gas or equivalent	Remediate 1 hectare wooded area	Up to 1,000,000 customer days lost or equivalent total customer bill increase	Prolonged, adverse national media attention; significant loss of trust among stakeholders

[a] This table qualitatively describes the consequence ratings by risk dimension; quantitative consequence ratings (not shown here) are used during detailed risk assessments.
[b] Quantitative consequence ratings are aligned with the World Health Organization (WHO) approach.
[c] Greenhouse Gas (GHG), Standard Cubic Meter (SCM).
[d] Pressure Relief Valve (PRV), Intermediate Pressure (IP), High Pressure (HP), Extra High Pressure (XHP)

At EGD, adequately managing risk means reducing risk to conditionally tolerable or broadly tolerable levels, rather than as low as possible, as seen in **Figure 4.1-7**.

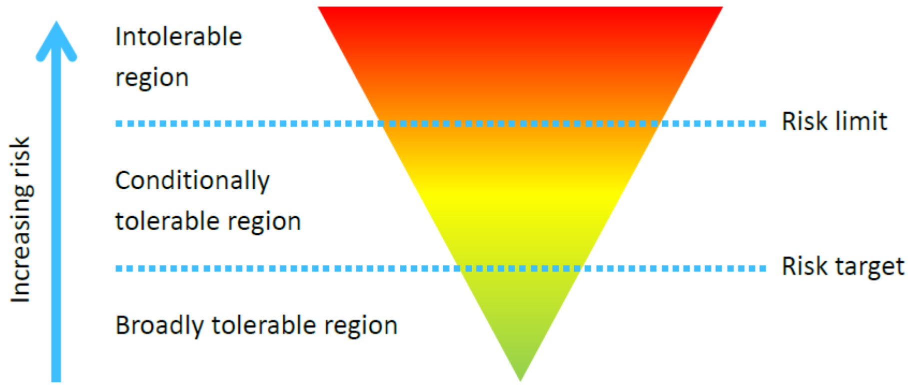


Figure 4.1-7: EGD's Risk Tolerance Framework

When a risk is evaluated to be in the intolerable (red) region, the risk is labelled as mandatory and must be addressed. Other mandatory initiatives are those driven by compliance requirements and third party relocations. These types of risk are summarized in **Table 4.1-4**.

Table 4.1-4: Types of Risk

TERM	EGD DESCRIPTION
Mandatory	A risk that must be addressed within its required time window. Mandatory risks can be the result of: • Compliance requirements • Exceeding a risk limit where the risk is assessed within EGD's intolerable risk region • Third-party relocation driven • Program work with sufficient history and risk to warrant continuation
Compliance	Required adherence with applicable laws and regulations, industry codes, standards, and internal policies.

EGD's objective is to reduce all known risks in the intolerable (red) region to the conditionally tolerable (yellow) or broadly tolerable (green) regions, except where there are exceptional reasons for the risk to be retained.

Risks identified between the risk limit and risk target may be considered tolerable on the condition that all reasonable and practicable measures to reduce risk have been implemented and they confer certain benefits (such as the provision of energy). The broadly tolerable region represents risks generally considered insignificant and adequately controlled. These risks are not typically reduced unless reasonably practicable measures are available.

A reasonable and practicable measure to reduce risk is one where the risk reduction action is based on relevant good practices and where the project feasibility and cost to implement the risk reduction action does not seem greatly disproportional to the benefits achieved.

4.1.3.5 Utilize Asset Management Tools that Evolve to Meet Business Needs

EGD has been implementing and continues to evolve its asset management tools for use by the business; an overview of these tools is provided in **Section 4.2.6**. Asset management tools provide the business with the ability to gather and make transparent and defendable decisions through the assessment of asset condition and risk.

In addition, an asset management tool named PowerPlan Asset Management Planning (PP-AMP) – formerly called Riva, is used at EGD. PP-AMP has three specific business uses: the Risk Register, Solution Planning, and Portfolio Optimization. The tool streamlines the factors and considerations for asset investment planning by:

- Proactively incorporating risk management opportunities and mitigation options
- Managing solution planning by determining the value of options, based on how they align with the Asset Management Policy and asset management principles
- Performing portfolio optimizations using What-If scenarios to determine an optimal spend profile

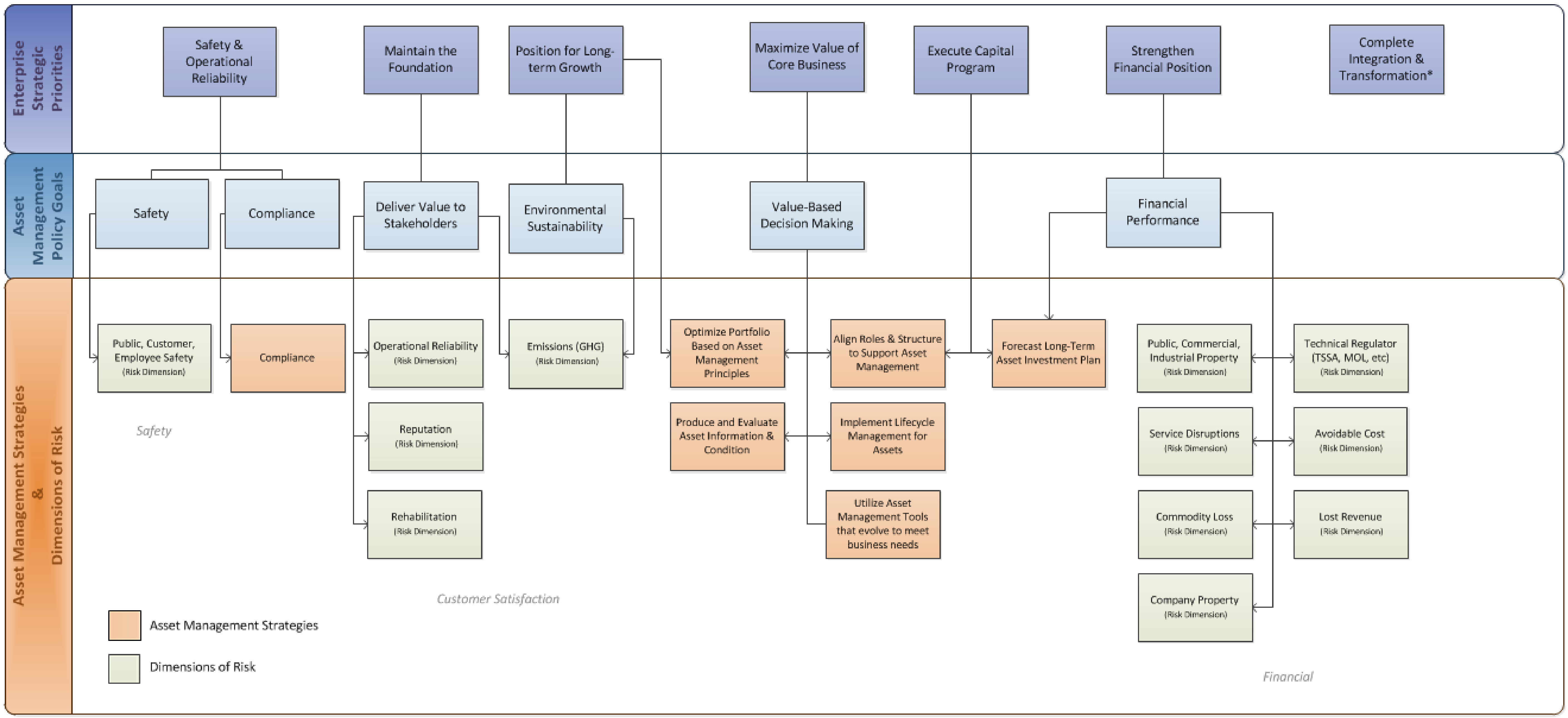
These activities support transparent and defendable funding allocations.

4.1.3.6 Forecast Long-Term Asset Investment Plan

The alignment of EGD's Asset Management Program with organizational priorities and a well-defined asset portfolio enables the development of asset-specific programs and projects. The Asset Management Plan is a coordinated activity combining these components to forecast a long-term (10-year) plan for asset investments. Forecasting long-term asset investment plans allows EGD to identify future needs for asset investments and make proactive decisions. The capital investment summary for EGD's Asset Management Plan can be found in the Summary of Capital Expenditure (**Section 6**).

4.1.4 Alignment of Enterprise Strategic Priorities and Asset Management Strategies

Figure 4.1-8 illustrates how EGD's Asset Management Policy, Strategies and Risk Dimensions align with the Company's Enterprise Strategic Priorities. This alignment is the core of EGD's Asset Management Strategic Framework.



* Dependent on MAADs Application Decision

Figure 4.1-8: EGD's Alignment of Enterprise Strategic Priorities and Asset Management Strategies

4.2 ASSET MANAGEMENT CORE PROCESS

EGD's Asset Management Core Process (**Figure 4.2-1**) is based on the remaining chevrons of the Value-Based Asset Management Model.

The detailed process, as well as the integral role of Asset Analytics, Asset Information Management, and Tools (the "inner rings" of the model), is explained in this section.

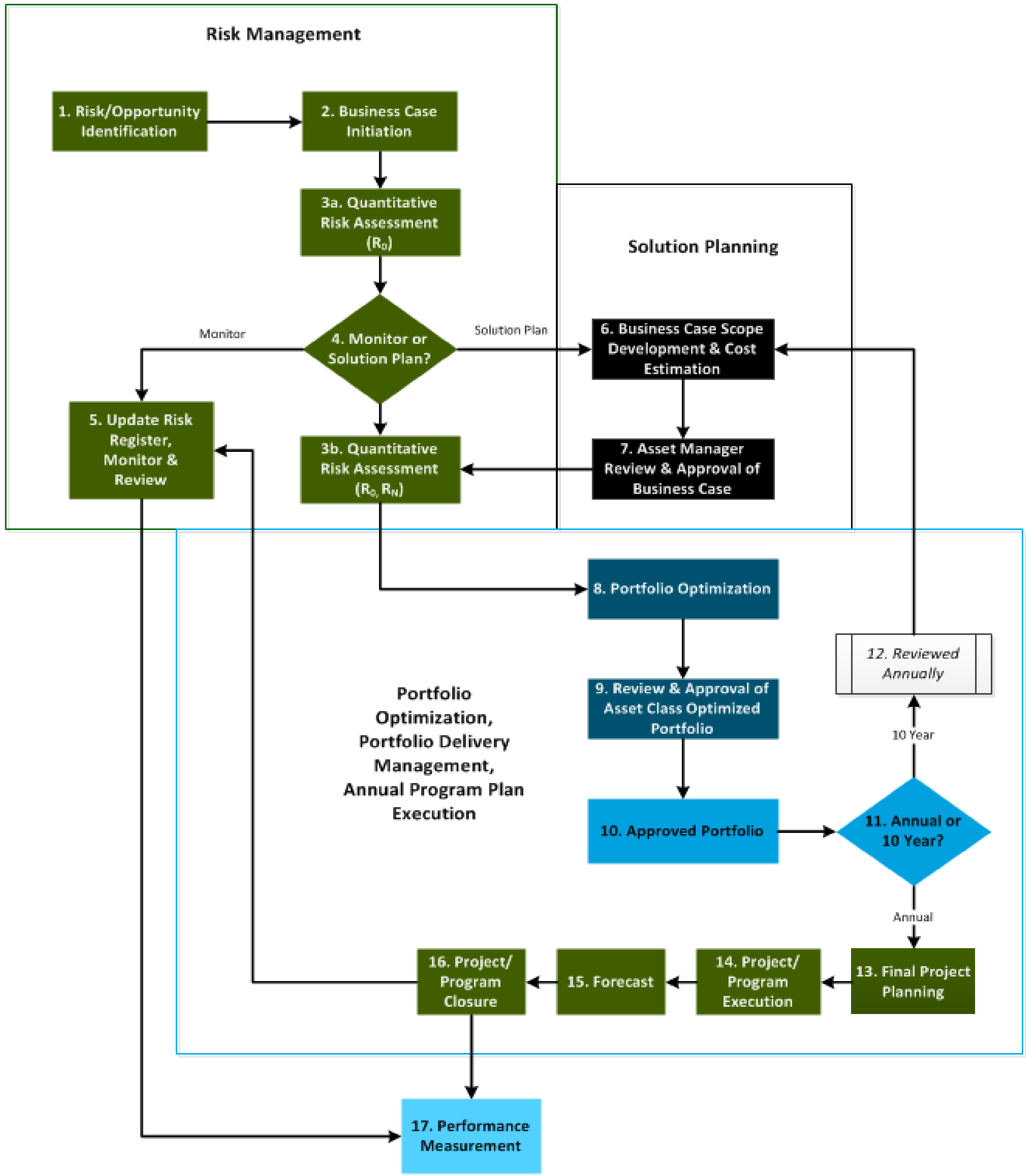
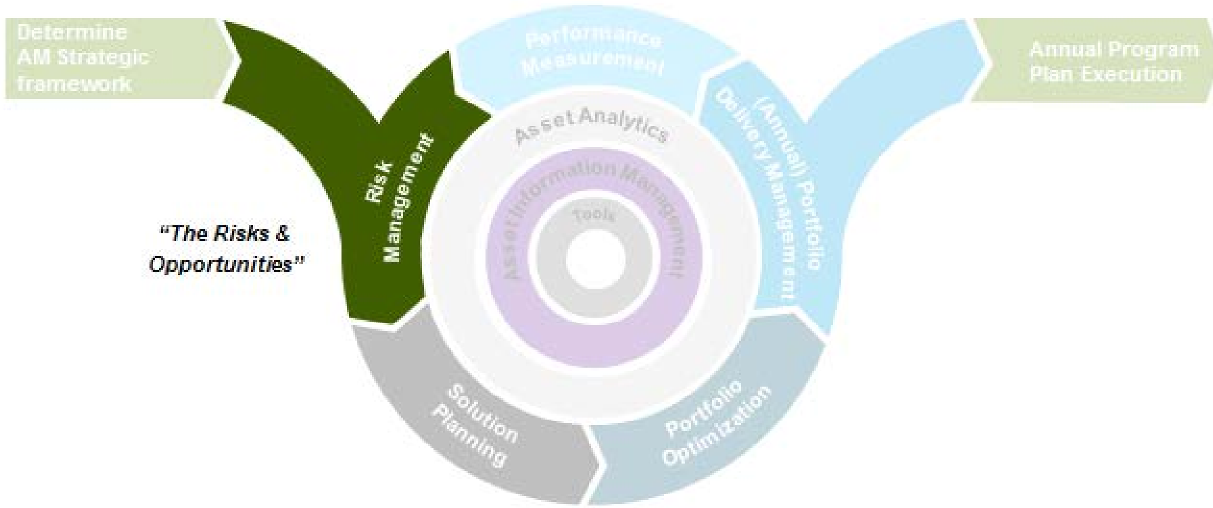


Figure 4.2-1: EGD's Asset Management Core Process

4.2.1 Risk Management



The Asset Management Core Process begins with an identified **Risk/Opportunity**. ACMs are responsible for capturing and managing risks and opportunities within their asset class. These risks and opportunities are often identified by business stakeholders as an issue or concern with the associated cause(s), any existing safety measures, the influencing factors, and if known, a proposed remediation option. Asset condition assessment reports also play a key role in the identification of risks at EGD (see **Section 4.2.6**).

The ACM initiates a detailed **Quantitative Risk Assessment** (QRA) and simultaneously assigns the risk to the business for Solution Planning (**Section 4.2.2)**. All identified risks/opportunities and their assessments are stored in EGD's **Risk Register** for continuous monitoring and review.

EGD's QRA is used to calculate current risk (R_0) as well as the post-solutions risk (R_1, R_2… R_N). A risk engineer works with appropriate Subject Matter Advisors (SMA) to complete the QRA for the identified risk/opportunity. The QRA uses a Risk Bowtie model for the evaluation process, as illustrated in **Figure 4.2-2**. Completed QRAs provide the risk information used in Portfolio Optimization.

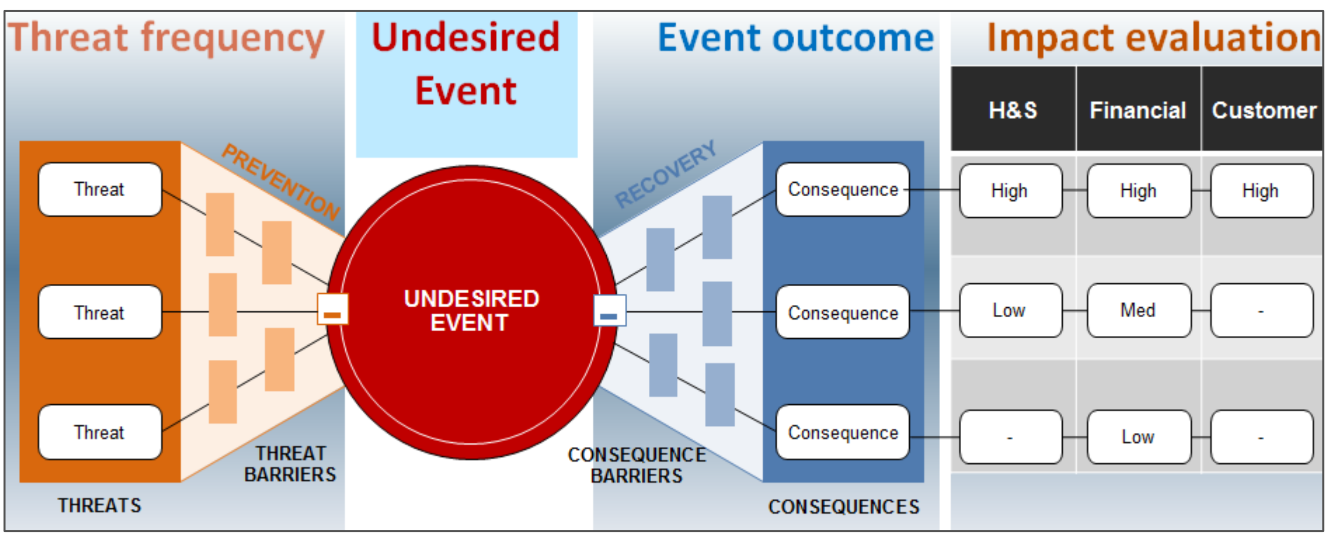


Figure 4.2-2: Risk Bowtie Model

The risk engineer completes three areas of evaluation using the Risk Bowtie model:

- **Frequency Evaluation**
- **Outcome Evaluation**
- **Impact Evaluation**

At EGD, the QRA and Solution Planning processes occur simultaneously because it is necessary to evaluate the risk of an existing issue as well as the post-project risk for each identified solution option. The initial risk (R_0) can be quantified using this process either independently or at the same time as the post-project risk (R_1, R_2… R_N).

The QRA results in a risk score for the identified risk/opportunity. The score is comprised of risk values for the 12 risk dimensions outlined in **Table 4.1-2.** These scores can be summed for each risk category: Safety, Financial, and Customer Satisfaction and result in a risk score that is uniquely weighted for projects.

An illustration of an initial and post-solution risk is illustrated in **Figure 4.2-3**. The area of the pie chart represents the total risk, where the post-solution risk is less than the initial risk.

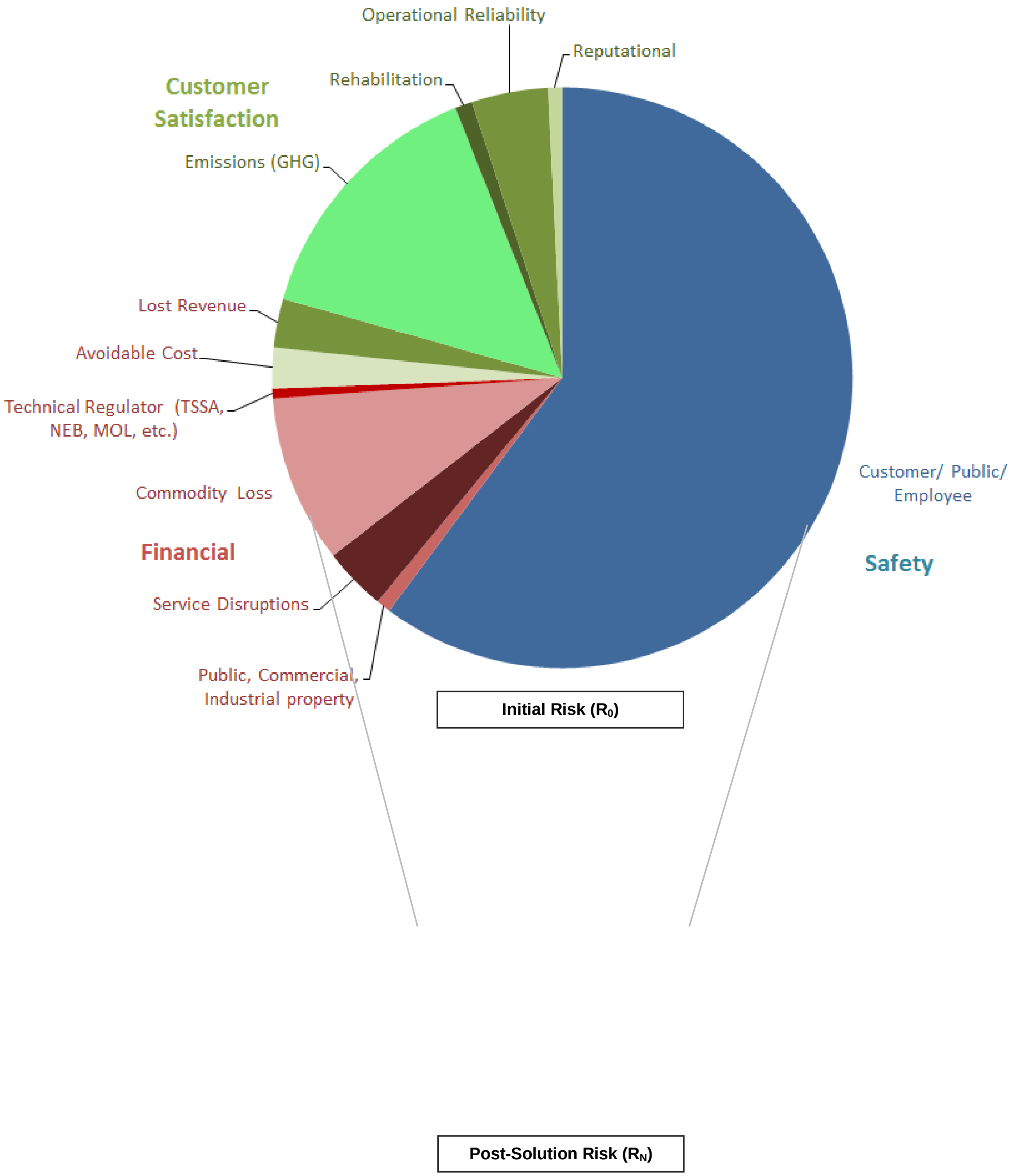


Figure 4.2-3: Initial and Post-Solution Risk

At EGD, risk matrices (shown below) are used to depict the quantified risks/opportunities and visually illustrate the risk mitigated through solutions. R_0 depicts the calculated pre-solution risk value and R_N depicts the calculated post-solution risk value. The R_0 and R_N values are used to inform the solution planning as described in **Section 4.2.2** and the portfolio optimization as described in **Section 4.2.3**. The color coding of the matrices indicates the risk tolerance limits per risk dimension as described in **Section 4.1.3.4.** It is important to note that risk tolerances are defined for each risk dimension but do not exist for total risk.

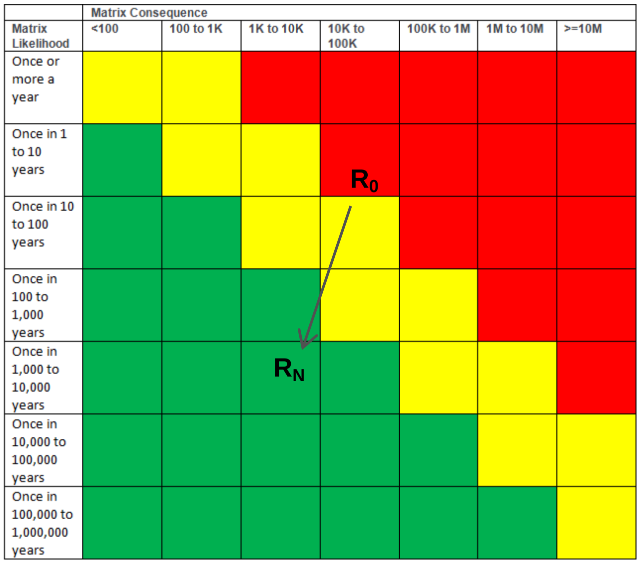


Figure 4.2-4: Safety Risk Matrix

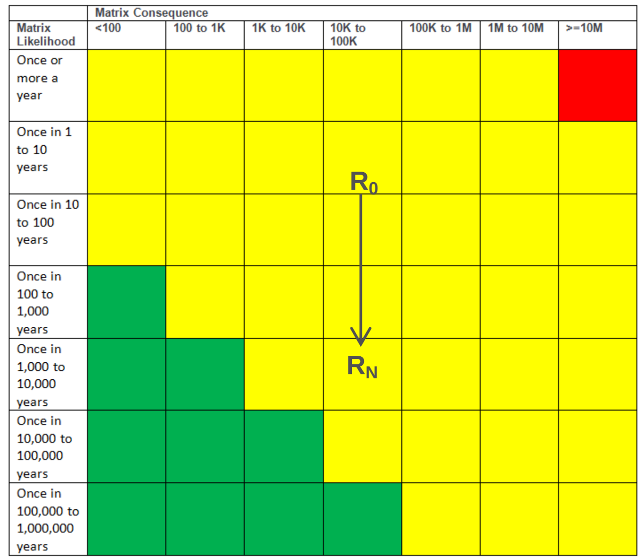


Figure 4.2-5: Financial Risk Matrix

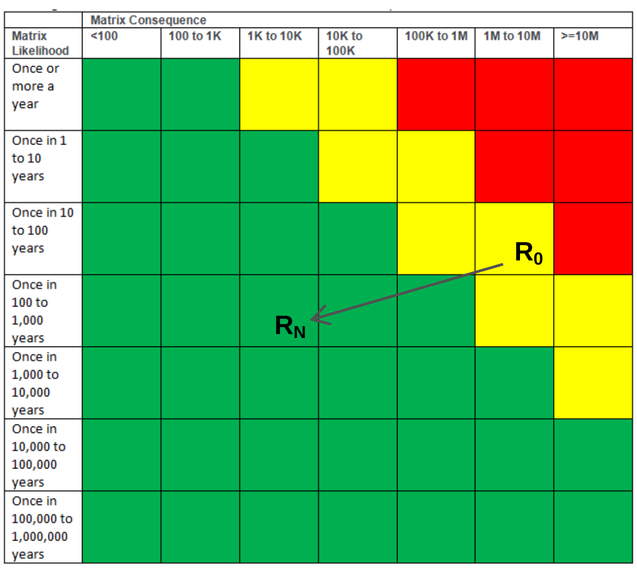


Figure 4.2-6: Customer Satisfaction Risk Matrix

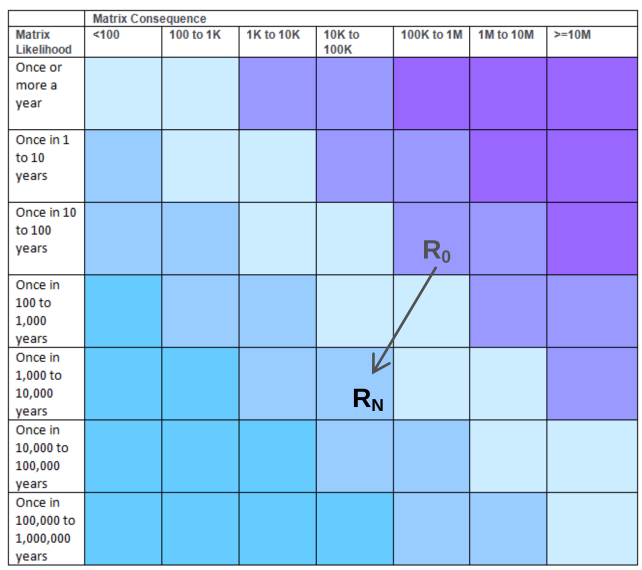
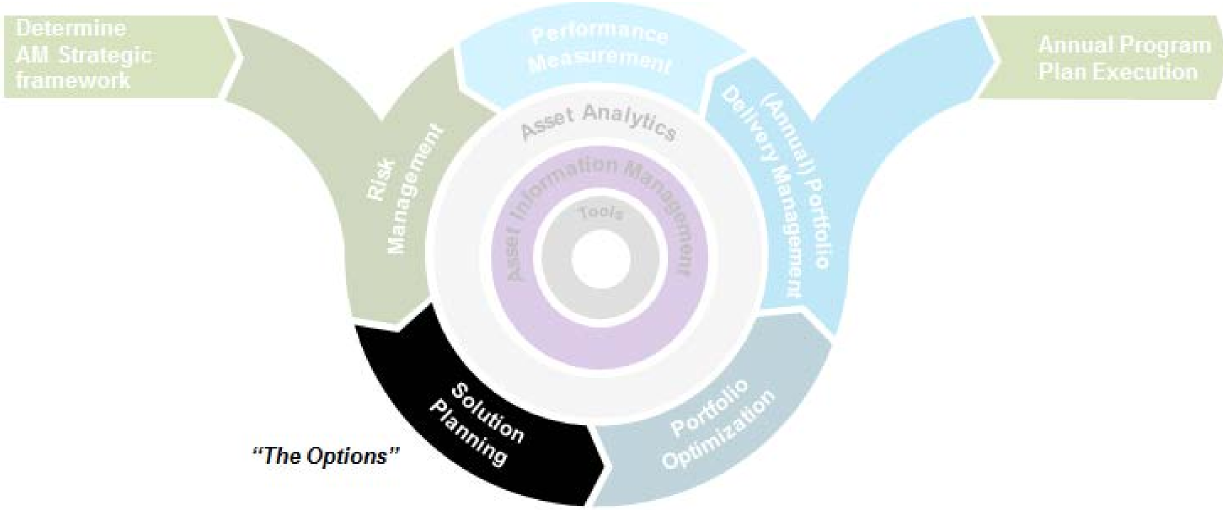


Figure 4.2-7: Total Risk Matrix

4.2.2 Solution Planning



The **Solution Planning** process is initiated by the ACM through the creation of a business case, occurring in parallel with the QRA process. A business case contains all information related to the mitigation strategy of the identified risk/opportunity. During the **Scope Development and Cost Estimation** phase of solution planning, methods are identified to address a risk or opportunity (solution options). This requires a clearly defined scope, a proposed earliest and latest start year, and the associated cost for each feasible option. Options to address a risk/opportunity could be in the form of a *Project* or a *Program*, as described in **Table 4.2-1**.

Table 4.2-1: Project and Program Descriptions

INITIATIVE TYPE	EGD DESCRIPTION
Project	A one-time individual initiative with a distinct scope and timeline.
Program	An over-arching initiative to address a risk/opportunity that is/will be comprised of multiple projects with varying scopes and timelines.

Cost estimating is an important activity for the Solution Planning process and the resultant 10-year Asset Management Plan. Associated costs of a solution include the direct capital costs, retirement costs, and rebillable credits. In addition, any avoided and/or additional operating and maintenance (O&M) costs are estimated, where known. All estimates are based on current year costs (with the exception of programs that have a defined scope) with unit rates, and with an inflation rate applied. Note that scoping and estimating for earlier years of the plan will be more accurate than later years.

All solution options have a cost estimate and the level of accuracy of the estimate is established using Estimate Classes, summarized in **Table 4.2-2.** The class of the estimate also informs the level of contingency applied to the project or program.

Contingency is described as the amount of funds budgeted to account for unquantified project costs at the time the estimate is completed; this cost is intended to cover potential risks during execution. Contingency is generally included in estimates with the expectation for it to be expended, and is allocated on a project-by-project basis based on project risk and scope of work.

Table 4.2-2: Estimate Class Descriptions

CLASS	ESTIMATE DESCRIPTION	SCOPE MATURITY	CONTINGENCY LEVEL
Class 5	High-level cost estimate	Very Low	High
Class 4	Estimate based on initial information	Low	
Class 3	Estimate based on cost estimating tools and reports	Moderate – High	
Class 2	Estimate based on Request for Proposal (RFP)	High	
Class 1	Estimate based on quote or project completion	Very High	Low

With a responsibility to manage the risks and capital budget associated with their asset class, ACMs review and approve all business cases submitted for portfolio optimization. They ensure business cases considered for portfolio optimization have feasible solution options and will mitigate the risks/opportunities identified. Following their review, the ACM can approve a business case or request further work on developing the solution.

4.2.3 Portfolio Optimization

With QRAs and Solution Planning work complete, the next step in the process is **Portfolio Optimization**. Portfolio Optimization is facilitated and governed by the Asset Management Optimization (AMO) group. Portfolio Optimization is performed in PP-AMP, creating a work plan that optimizes the timing and solutions of all capital projects to reduce risk. In the optimization, Annual Net Direct Capital is constrained, and the lifetime pre- and post-solution risks determined by QRAs are analyzed to minimize the total risk associated with the portfolio over a specified timeframe.

ACMs review and propose all projects and programs considered for optimization. A 10-year time frame is analyzed to determine the long-term capital forecast. Based on required timing, projects and programs have varying degrees of project specification, where work details proposed earlier in the plan are more refined than work details proposed towards the end of the 10-year span. For this reason, programmatic spend is proposed to address risks, and projects are continually defined and attached to the program as scope refinement occurs.

When the ACMs review projects and programs for optimization, they also identify whether the initiative is classified as compliance and/or mandatory based on EGD's defined criteria in **Table 4.1-4.** Compliance projects are validated by compliance verifiers, and mandatory projects are validated by the AMO group. This step plays a critical role in optimization as projects identified as mandatory and/or compliance are automatically slotted at the required time, rather than using risk and cost to determine optimal timing. Projects/programs that have not been identified as compliance or mandatory are free to shift within the optimization timeframe.

Prior to optimizing, the AMO group presents an initial portfolio representing the preferred option and timing of the projects/programs proposed by the ACMs (as seen in **Figure 4.2-8**: Pre-Optimization Profile Illustration). This results in an inconsistent spend profile over the 10 years, with a much larger proposed spend in earlier years.

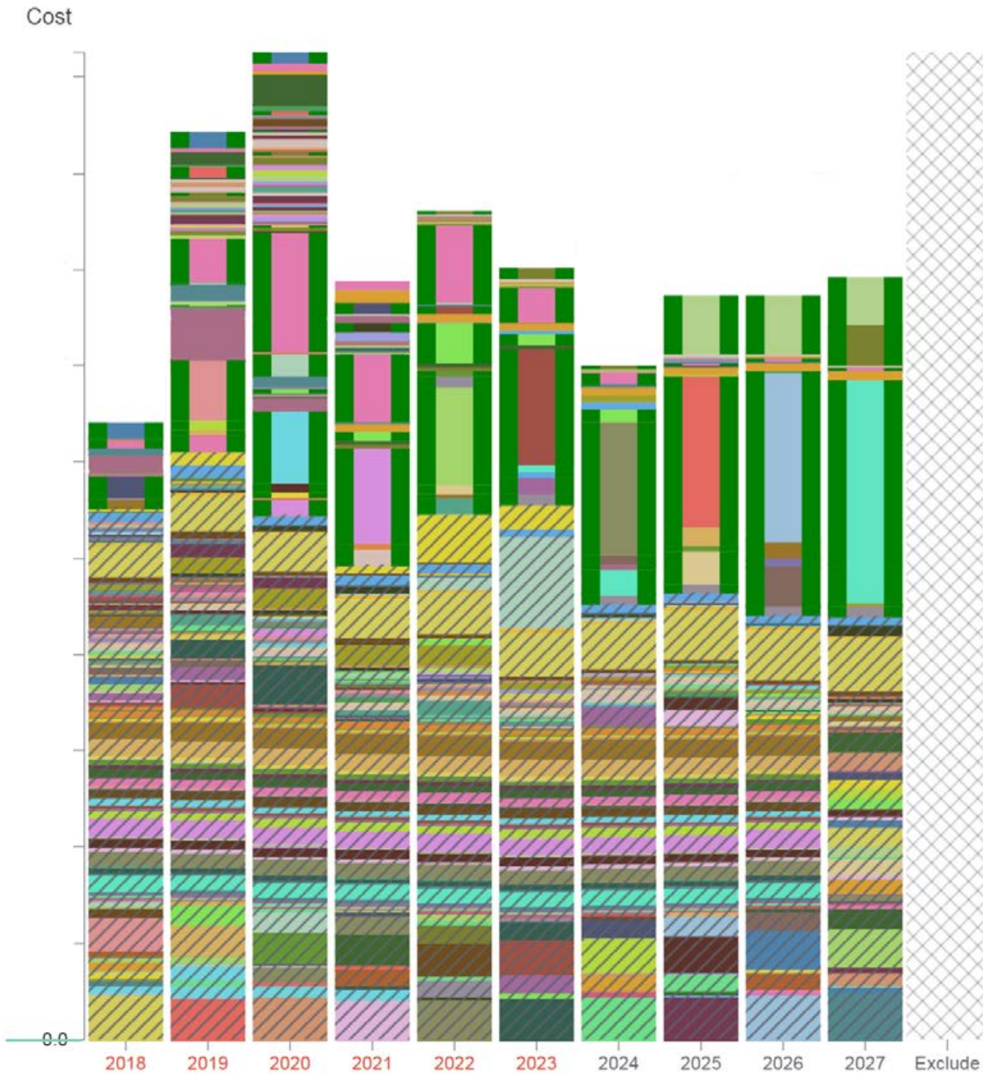


Figure 4.2-8: Pre-Optimization Profile Illustration

Optimization scenarios are determined through the consideration of the following:

- Approved or proposed budget
- Historical capital spend at the organization
- Known intolerable risks
- Asset life cycle strategies
- The original proposal of work (pre-optimization) and an understanding of the associated compliance and mandatory projects/programs

The AMO group uses the leveler tool in PP-AMP to optimize and analyze different scenarios of capital spend by varying the net direct capital per year. This exercise helps the group understand the effects of project timing, option selection, and risk. The results from these runs, as illustrated in **Figure 4.2-9**, are reviewed with the ACMs and differences between runs are highlighted.

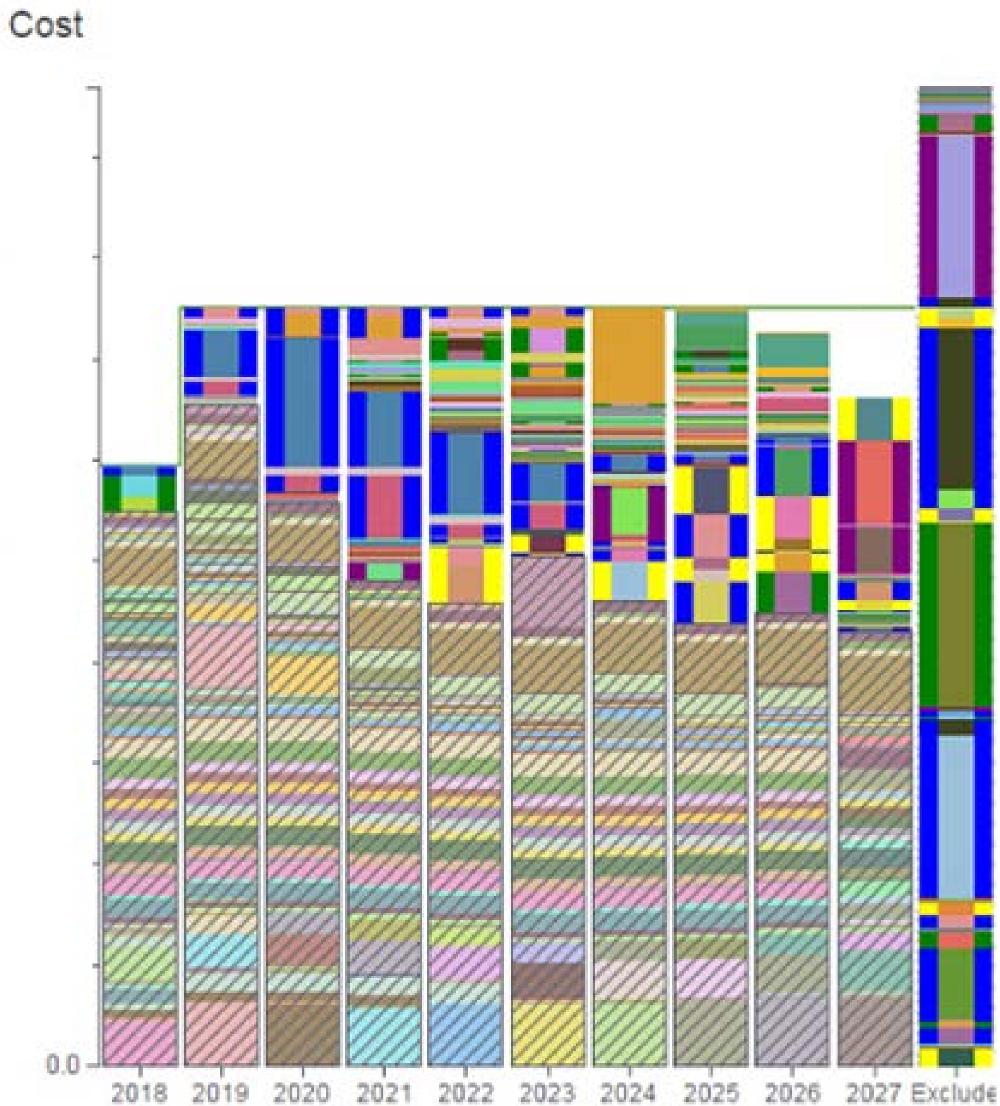


Figure 4.2-9: Post-Optimization Profile Illustration

Based on the risk and the ability to complete mandatory and compliance work, the AMO group recommends an optimization scenario. This scenario is reviewed and refined with the ACMs to prioritize a final portfolio recommendation. This recommendation is endorsed by the ACDs, taking into account the feasibility of the work plan with respect to timing and resourcing. The resultant portfolio is then submitted to the Vice President of Engineering & Asset Management for approval.

The Finance and Regulatory team are involved throughout the process to ensure that the rate impact is understood.

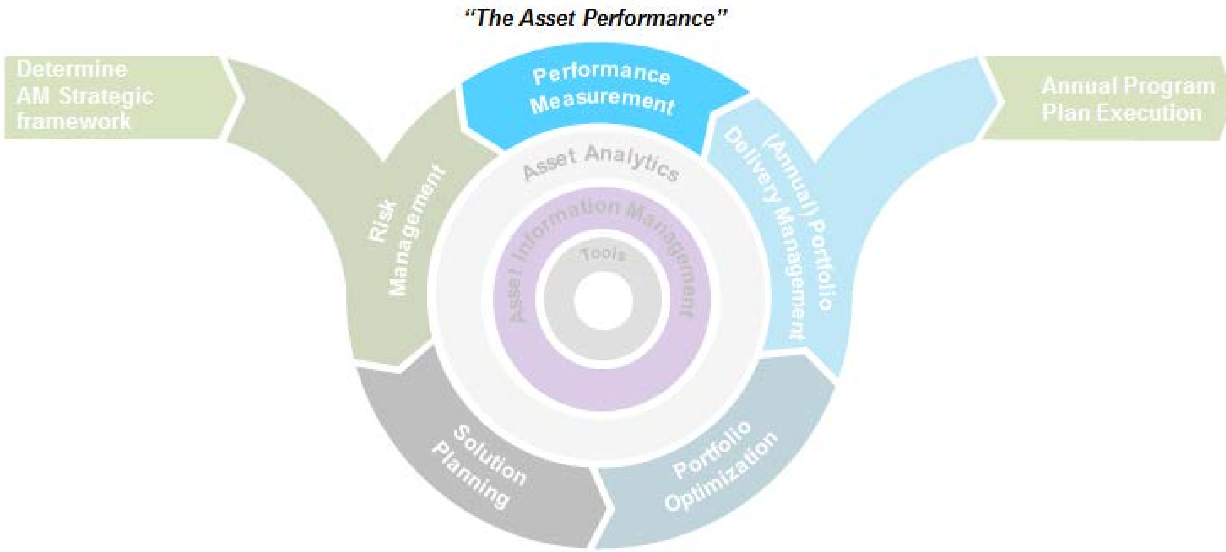
4.2.4 Portfolio Delivery Management and Annual Program Plan Execution

Once the optimized portfolio is approved, the AMO group delivers the portfolio of work to the ACMs (inclusive of the immediate year's requirements), which is then distributed to all business stakeholders for execution. During project planning and execution, the business continuously forecasts project and program costs, and reports on actual incurred costs.

EGD acknowledges that the identification of risks and the execution of projects is dynamic. As a result, the portfolio is reviewed twice following optimization, to account for execution status, outstanding risks and opportunities, and emerging risks and opportunities. During the year, the project scope may change or new projects may arise, resulting in cost pressures to the current portfolio. As these pressures are identified, trade-off decisions are made based on risk and available capital, a direct demonstration of EGD's Plan-Do-Check-Act model.

The execution of the annual work plan is monitored and adjusted monthly through the forecasting process and informs the performance of EGD's Asset Management Program.

4.2.5 Performance Measurement



Performance measurement provides insight to asset performance, asset management performance, and the effectiveness of the asset management system.

To determine asset management performance and the effectiveness of the Asset Management Program, four key areas are evaluated:

- The end-to-end asset management process (LRROI)
- Delivery to plan of the approved portfolio (scope delivery to plan and capital budget delivery to plan)
- Adherence to asset class objectives and life cycle policies (**Section 5**)
- Accomplishment of specific asset management objectives

Lifetime Risk Return on Investment (LRROI) is used to inform optimization where the risk mitigated by a capital investment is normalized by the net direct capital required. LRROI is a measure indicating the efficiency with which risk is reduced across all asset classes. It is calculated using **Equation 1**. The Discounted Lifetime Risk Reduction is calculated using **Equation 2**[6] and represents the present value of the risk reduction over the useful life of the asset. Customer satisfaction and financial risk are discounted over the life of the asset, while safety risk is not, as it is of paramount importance.

$$\text{LRROI}=\frac{\text{Discounted Lifetime Risk Reduction}}{\text{Total Net Capital Investment}}$$

Equation 1: LRROI Calculation

$$\text{Discounted Lifetime Risk Reduction}=(\text{Safety Risk Mit}\times\text{Useful Life})+\left(\text{Fin Risk Mit}\times\frac{1-(1+\text{pretax WACC*})^{-\text{useful life}}}{\text{pretax WACC}}\right)+\left(\text{CSAT Risk Mit}\times\frac{1-(1+\text{pretax WACC})^{-\text{useful life}}}{\text{pretax WACC}}\right)$$

**WACC: Weighted Average Cost of Capital*

Equation 2: Discounted Lifetime Risk Reduction

The annual budget process defines capital allocations to projects based on a review of project scope, cost, compliance requirements, risk, and risk reduction to be achieved. This sets the annual target for the LRROI at the beginning of the calendar year. Achieving the target LRROI indicates the successful execution of the annual work plan, where cost and scope pressures are managed to ensure the risk reduction is aligned with the planned capital investment.

Scope Delivery to Plan is the comparison of the approved portfolio project list to actual projects completed at year end. Variances are explained to ensure the Asset Management Framework is supporting the reduction of risk and realizing optimal asset value.

Capital Budget Delivery to Plan is informed monthly by the capital forecast. This ensures the governance and controls are in place to optimize the capital plan while operating within an approved budget. It also supports continuous improvement for cost estimating, where the variance between estimate and actual costs are understood and learnings are incorporated in future planning.

Asset Class Objectives have been defined for all asset classes at EGD. These objectives, aligned with asset management goals and principles, outline asset requirements to support successful business operations. Life cycle management is applied across all asset classes to specify policies that govern decision-making throughout the four stages of the asset life cycle: Acquire/Create, Utilize, Maintain, and Renew/Retire. Adherence to the asset class objectives and life cycle policies ensures consistent and holistic evaluation of risks and opportunities, setting the foundation for successful asset planning and value-realization. Asset class objectives are found in Customers and Assets (**Section 5**).

The **Asset Management Scorecard** details specific asset management execution elements supporting the overarching Asset Management Strategies. The accomplishment of these elements informs senior management of the effectiveness of the Asset Management Team in maturing the asset management system.

Asset performance is evaluated in accordance with specific asset objectives and life cycle policies outlined in Asset Management Strategies (**Section 4.1.3)**. Asset performance measures ensure day-to-day operations are supporting overarching strategic priorities.

[6]Complete details available in formal EGD risk documentation.

4.2.6 Asset Information, Tools, and Asset Analytics

The Value-Based Asset Management Model relies on asset analytics, asset information management, and the tools and processes to inform decisions and activities through the various stages of the Asset Management process. Like other assets, data requires processes and controls to govern its acquisition, use, maintenance, and final disposition. This section outlines the methods and tools (unique to each asset class) used at EGD to manage data and use it for analysis in a defendable and repeatable way.

4.2.6.1 Asset Information Management

Asset data provides the foundation for asset life cycle decision-making, as outlined in Asset Management Strategies (**Section 4.1.3**). Asset data exists in both structured (from databases residing within information systems), and unstructured (on paper and scanned) forms. Asset information derived from these sources, supported by company and industry knowledge, is leveraged for asset analysis and modeling to:

- Understand condition and predict risk
- Support risk and opportunity assessments
- Inform and support asset health reviews and Engineering Reliability Assessments
- Establish asset inventory and population over time
- Ensure compliance with company policy and regulatory requirements
- Make operational asset decisions, e.g. emergency response
- Ensure safe and reliable operations e.g. core work, maintenance

With the company's growing focus on asset, integrity, and process safety management, there is a need for various groups in Operations, Integrity, and Asset Management to perform analyses based on a common understanding of hazards, asset master data, and a current understanding of the asset condition. Tools and methods to collect, store, manage, and use this data in a consistent and repeatable way are described in **Table 4.2-3.**

As EGD evolves in implementing data tools and methods, it also needs to develop and mature its data sets and analytics requirements. Asset management is based on the balance of performance, cost, and risk – **Figure 4.2-10** shows how these factors are relevant to the work that EGD undertakes in relation to data.

- There is a cost to acquiring data through the installation and maintenance of assets, storing the data, managing changes to it over the life of the asset, and retaining the data in systems.
- Data must perform (fit for purpose) and support the business decisions. As the organization’s asset management needs evolve, its data requirements must also evolve.
- Defendable decisions require appropriate data, and where data is not accurate or complete, there is a risk that a sub-optimal decision will be made.

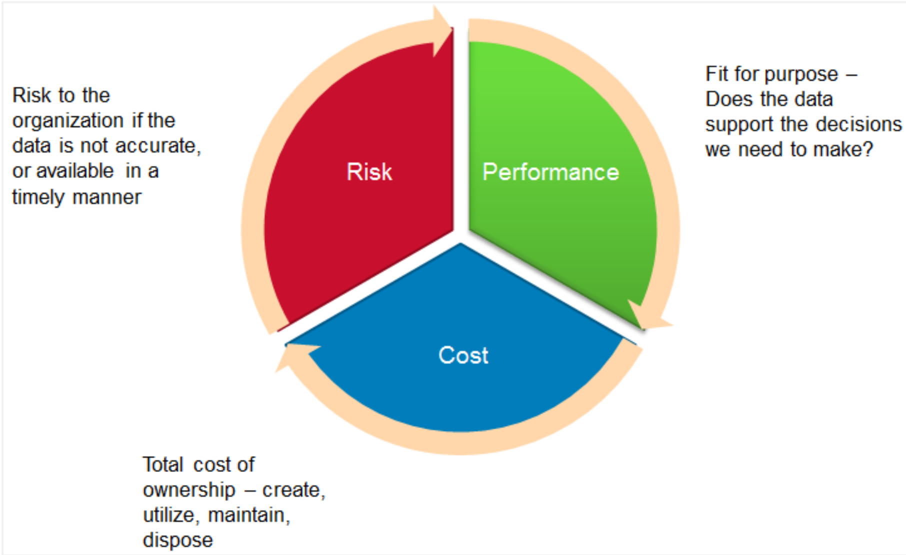


Figure 4.2-10: The Role of Data in Asset Management

Data for EGD's gas carrying assets is categorized as follows:

- **Master data**
  Information such as identification, location, and material/equipment descriptions is captured at the time of installation and stored within established systems of record. This data establishes the asset inventory indicating what, how many, and where assets are located, which builds the foundation of asset management decisions. Master asset records are updated through their life cycle as required through maintenance activities and record corrections.
- **Reference data**
  Information such as material specifications and codes is used to classify asset records as they are created and updated.
- **Planning data**
  Information such as preventive maintenance plans is used to plan and execute maintenance activities needed to optimize asset performance.
- **Transactional data**
  As construction, inspection, repair, and decommissioning work is performed on assets in the field, information is captured on these events in terms of type of work performed, scheduling, work completion details, materials consumed, and costs incurred. This information is used to inform the overall cost, performance, and risk associated with these assets. Maintenance history, derived condition, and failure information are used as inputs to models for building inspection/repair/replace programs.

To ensure the availability of information required for operational and strategic decisions now and in the future, EGD continuously assesses the condition of its gas carrying asset data through various means:

- **Data quality metrics and reporting**
  EGD runs reports according to set schedules on data sets pertaining to the gas carrying asset classes. Assessment results are captured in the form of standard data quality dimensions (accuracy, completeness, consistency, uniqueness, timeliness, and validity) and routed to business users to make the appropriate records updates.
- **Data profiling**
  On a periodic basis, statistical profiles of the data housed in key enterprise information systems are generated. Profiling results indicate completeness and consistency of values within data fields. Reviewing these results with business users allows for criticality assessments of business data usage and prioritization of data validation activities.
- **Business process evaluation**
  On a periodic basis, key business processes producing and consuming asset data (whether recently created or historical) are completed. Data quality gaps are subsequently identified (using standard data quality dimensions), ranked, and prioritized for remediation based upon relative impact on the processes and modeling that use the underlying data.

Generally, gas carrying asset data is fit-for-use for operational process-related tasks (such as construction and maintenance operations), however it requires some further refinement to be used for analytics (such as a risk assessment or an asset health review). Using the data for advanced modelling and forecasting was not foreseen when these historical data was captured. Data improvements have been identified and are currently underway to improve its fitness for purpose.

Roles must also evolve to provide sufficient focus on managing data throughout the asset life cycle (Acquire/Create, Utilize, Maintain, and Renew/Retire), ensuring quality data is used in decision-making. Current data management efforts include:

- **Data improvements**
  Data sets are prioritized for remediation according to the business need for the data and its impact to risk reductions. Improvements take the form of corrections to historical records that are not fit for purpose in the context of emergent business needs such as Asset and Integrity Management, capture of missing records, and improvements to associated business processes. These improvements increase the overall performance and risk-reduction effectiveness of data assets, supporting operational processes and analytics. For example, data validation is currently underway for data sets relevant to the Pipe and Station asset classes to ensure accuracy and completeness of key data attributes such as installation date (from which asset age is derived), material, and location.
- **Records management**
  Record capture within content management systems is required for unstructured records to achieve compliance with records management policies for retention and accessibility. Ongoing work identifies and catalogues historical records for all installed plant records.
- **Data governance**
  EGD has established data stewardship roles focused on the maintenance and improvement of asset records. Asset data stewards monitor data quality, keep abreast of data quality issues, advise business users in the selection and use of data sets to meet business needs, and identify and champion data improvements. These roles align with other roles established for process advisory and information system support.
- **Metadata compilation**
  Data stewards and other SMAs are engaged in the gathering, drafting, and compilation of business glossaries, system data dictionaries, data models, and other documentation supporting the identification and use of the most suitable asset data required to meet specific business needs.

A number of projects are currently underway or being planned to improve the quality of gas carrying asset data and to maintain records management compliance. Further, EGD is leveraging IBM Maximo, Click Mobile, and other purpose-built tools to capture information about the condition of assets during inspection and maintenance work.

4.2.6.2 Asset Analytics

The analytics required to support decisions in each asset class vary and are dependent on the relevant strategies for the asset class, and the quality and accessibility of data. Making defendable decisions can require a broad range of information and analytical techniques, as well as experience from both within and outside EGD. The goal is to combine these in an appropriate way for each type of asset to make decisions about its acquisition/creation, utilization, maintenance, and renewal/retirement. EGD has been developing and working to improve data quality and analytical techniques to support a wide range of decisions. Some examples of these are:

- **Descriptive analytics** uses data aggregation and data mining to provide insight into the past and to answer the question “What has happened?”. An example is the Failure Classification Platform where work orders are analyzed to determine the nature of the problem (e.g., leak or over-pressure), the component that failed (e.g., pipe or gasket), and the root cause (e.g., corrosion or third-party damage).
- **Diagnostic analytics** is a form of advance analytics using techniques such as drill-down, data discovery, data mining, and correlations, which examines data or content to answer the question “Why did it happen?”. An example is the preliminary statistical work that must be undertaken to determine the physical factors that are statistically relevant to an asset failure.
- **Predictive analytics** uses a variety of statistical techniques from predictive modeling, machine learning, and data mining that analyze current and historical facts to make predictions about future or otherwise unknown events to answer the question “What could happen?”. An example is the creation of leak projections and remaining asset life.
- **Prescriptive analytics** uses optimization and simulation algorithms to advise on possible outcomes and to answer the question “What should we do?”. An example is the use of decision support tools such as asset investment planning and replacement rate models.

Some examples of the models that have been developed at EGD are:

- **Quantitative Risk Assessment (QRA)**
  Using the Risk Bowtie model as the base, risk engineers examine the frequency of various “top events”. Examples vary by asset class but could include a gas leak, a vehicle failure, or a IT system outage. In each case, various safeguards in place are considered and evaluated, leading to a calculation of a total risk that can be compared across multiple asset classes. For a detailed description of the risk methodology, refer to **Section 4.2.1**.
- **Probability of Failure and Asset Health Indices**
  For some asset classes, historic failure data can be combined with structured tacit knowledge and statistical methods to establish a probability of failure based on age and other statistically significant factors . The probability of failure is used to establish an Asset Health Index – a measure of the current health of the asset population and its expected deterioration.
- **Decision Support Tools**
  Decision Support Tools have been developed to solve specific problems and run multiple What-If scenarios. PP-AMP for Asset Investment Planning is an example of a decision support tool that performs operation scenarios with different constraints. The Replacement Rate tool (another example of a decision support tool) has been developed to determine the expected number of asset failures based on various resourcing strategies. Decision support tools will be developed as business needs change and data becomes available.

As these models have been developed, there has been an increasing demand for better data and more complete modeling to better support decision-making. This is as expected and is managed through a continuous improvement cycle that is timed to meet the production of the annual Asset Management Plan, and to support other decisions that are required on a more ad-hoc basis.

4.2.6.3 Tools

Table 4.2-3 outlines the data systems that hold various forms of asset data (master, reference, planning, and transactional) at EGD.

Table 4.2-3: Data Systems and Tools

SYSTEM	DESCRIPTION
PP-AMP	Operational Risk Register and business case repository used for portfolio optimization.
ArcGIS	Geographical representation of gas carrying assets. Includes modules for leak and cathodic protection surveys.
Maximo (Gas Distribution)	Enterprise asset management system containing master data on gas carrying assets, related work, and preventive maintenance plans.
Maximo (Gas Storage)	Enterprise asset management system containing master data on gas storage assets, related work, and preventive maintenance plans.
Click Mobile	Field mobility solution used to complete Maximo work orders and update asset information.
SCADA	Supervisory Control and Data Acquisition system to monitor and control network operations.
Flagship Navigator and Fleet Focus	Systems used by Fleet and Equipment containing information related to vehicles, heavy equipment, and tools.
IBM - SPSS	A toolset used to support the development of decision support tools, failure classification tools, probability of failure models, and risk models.
PRIM (Pipeline Risk and Integrity Management)	A tool used to determine the expected remaining life of a pipe asset based on in-line inspection data and a crack propagation model. The tool includes factors to establish the risk related to a leak or rupture of the pipeline.
SAS, Reliasoft	Statistical Analysis packages used to perform statistical processing.

SYSTEM	DESCRIPTION
Excel, Access	Various tools, from quantitative risk assessments to the asset health review, are developed on these platforms before being migrated to a more robust platform.
FAST	FAST is a tool used to collect condition data at Network Operations sites, combined with other information to prioritize stations for replacement.
ServiceNow	A service management tool containing information and requests related to TIS assets.

5 Customers and Assets

5.1 CUSTOMER GROWTH

EGD delivers safe and reliable natural gas to over 2.1 million customers, forecasted to grow over the 10-year period of this Asset Management Plan. EGD services residential, commercial, apartment, and industrial customers within its franchise areas. Customer growth involves:

- Addition of new customers based on new housing or business starts
- Customers converting to natural gas from another fuel source
- Equipment and service upgrades to accommodate load growth of existing customers

The Customer Growth asset class evaluates customers' natural gas consumption needs and ensures demands are assessed and processed in accordance with the guidelines prescribed in the *EBO 188* report. The assets and costs within this asset class include materials and installations of mains, services, meters and regulating equipment.

The Customer Growth capital expenditure requirement for materials and asset installation is based on forecasted customer growth over ten years of this Asset Management Plan. Any capital expenditure requirements related to condition of existing assets (e.g., mains services, meters, regulating equipment, etc.) are addressed in the Pipe, Customer Assets, and Stations asset classes.

The addition of new customers as part of community expansion is managed through the Business Development asset class. Details of the Community Expansion Program are included in **Section 5.9.5**. Forecasted customer additions and capital costs for community expansion-related projects do not overlap with the traditional Customer Growth asset class. EGD continues to evaluate the scope of its carbon strategy and subsequent impact on customer growth forecasts. Refer to **Section 3.5** for an overview of IRP activities.

5.1.1 Customer Growth Objectives

The Customer Growth asset class is a key component of the Acquire/Create stage of EGD's Life Cycle Management Policy. It supports EGD's investment in new assets related to customer growth. Customer Growth objectives are listed in **Table 5.1-1.**

Table 5.1-1: Customer Growth Asset Class Objectives

ASSET CLASS OBJECTIVES	MEASURE OF SUCCESS
Ensure an engaged and positive customer experience.	• Customer Satisfaction Survey o Customer Satisfaction Index (CSI) Commitment metrics to install services by the required date
Ensure EGD provides new or upgraded natural gas services to residential, apartment, commercial, and industrial customers.	• Number of natural gas connections to all customers that: o Meet the acceptable Profitability Index (PI) metric, or o Provide the required financial Contribution in Aid of Construction (CIAC) to meet an acceptable PI metric • Investment and Rolling Project Portfolio PI metrics • Attachment rate of customers converting to natural gas

5.1.2 Customer Growth Inventory

EGD services residential, commercial, apartment, and industrial customers, defined further in **Table 5.1-2**. **Figure 5.1-2** and **Figure 5.1-1** profiles EGD's existing customer base by type and area (see **Section 2.3.1** for details on EGD administrative areas).

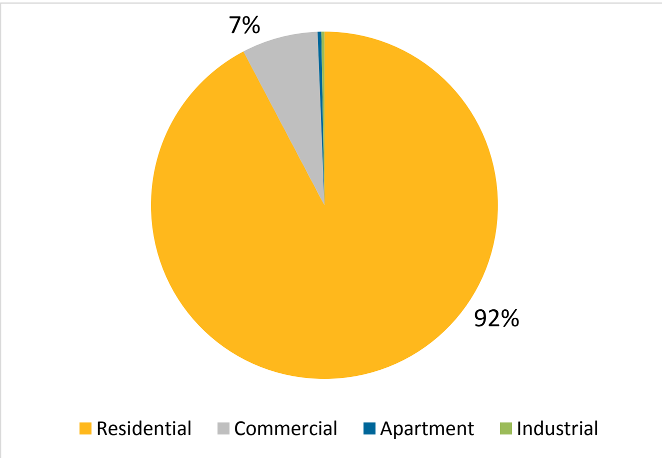


Figure 5.1-2: Customer Breakdown by Type (2017)

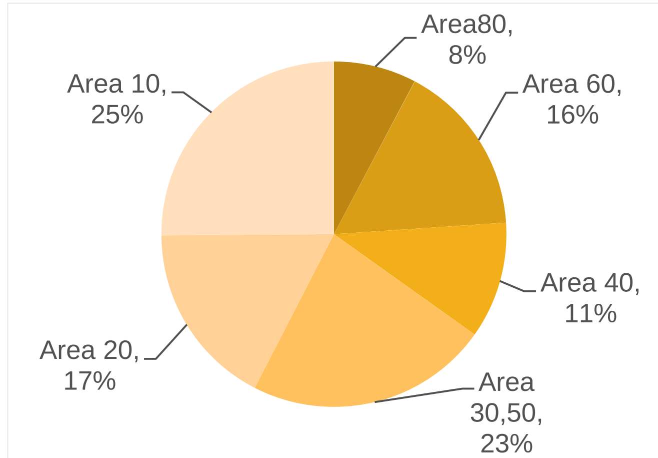


Figure 5.1-1: Customer Breakdown by Area (2017)

Table 5.1-2 describes EGD's customer classifications:

Table 5.1-2: Customer Definitions

CUSTOMER TYPE		CUSTOMER DEFINITION
Commercial *Uses natural gas for commercial purposes, buying and selling goods or services usually for a profit.*	Commercial New Construction	A customer intending to operate a commercial business in a newly-constructed building and intending to use natural gas to meet energy needs.
	Commercial Replacement	A commercial customer using a fuel other than natural gas for commercial business and is converting to natural gas.
Apartment *Uses natural gas for residential purposes in a large building containing multiple residential suites.*	Bulk-metered apartment	A traditional apartment customer is a multi-residential dwelling containing more than six units that is bulk-metered.
	Vertical Subdivision (Apartment ensuite)	A multiple unit residential building where each suite is individually metered.
Industrial *Uses natural gas for commercial purposes, manufacturing or processing products.*	Industrial New Construction	A customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.
	Industrial Replacement	An industrial facility using a fuel other than natural gas for industrial purposes and is converting to natural gas.
Residential *Uses natural gas for residential purposes.*	Residential New Construction	A new residential construction development of homes constructed by the builder for domestic purposes.

CUSTOMER TYPE		CUSTOMER DEFINITION
	Residential Replacement	A residential customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
	Subdivision	A subdivision builder constructing multiple homes in the same area within a common tract of land.

5.1.2.1 Customer Growth Background

Customer addition projects are associated with the construction and installation of mains, services, meters, and regulator stations to facilitate the connection of natural gas to new customers within EGD franchise areas.

Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different operational areas based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment, and mortgage rates

The forecast helps EGD determine its long-term system planning needs, including segments of the distribution system requiring reinforcement. The forecast is also used within the asset planning process to develop estimates of capital expenditure for customer addition projects over the term of the Asset Management Plan.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services, and meters
- Costs related to measurement and regulation equipment required to support customer growth

EGD extends its gas main within its franchise areas to serve new customers when economically feasible, as per criteria prescribed by the OEB in the *EBO 188* report guidelines. EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending gas mains

As part of the process to connect an applicant, EGD completes a construction estimate to assess the costs associated with installation. A feasibility analysis is then carried out to determine if the application for service installation is financially feasible, otherwise applicants may be required to pay a Contribution In Aid of Construction (CIAC). EGD determines the CIAC amount and the amount is communicated to the applicant in writing.

The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock, highway crossings, distance from existing mainlines, or sensitive environments

5.1.2.2 Customer Connections Feasibility

EGD expands its system in accordance with the OEB’s guidelines for the expansion of natural gas service. These guidelines are articulated in the *EBO 188* report. The intent of *EBO 188* is to facilitate rational expansion of natural gas service while protecting existing customers from undue cross-subsidization.

EGD uses a portfolio approach (Investment Portfolio and Rolling Project Portfolio) to manage system expansion activities and ensures that required profitability standards are achieved at both the individual project and the portfolio level.

Investment Portfolio: This approach evaluates feasibility on all proposed new distribution customer attachments for a particular test year and ensures required portfolio profitability index (PI) thresholds are achieved. The portfolio includes the costs and revenues associated with all new distribution customers forecasted to be attached in a particular year (including new customers attaching to existing main or infill services). It also ensures there are no undue cross-subsidizations in the short term. The investment portfolio is designed to achieve a PI threshold greater than 1.0.

Rolling Project Portfolio (RPP): This approach maintains a portfolio of system expansion projects over a rolling 12-month period. RPP is used as a management tool for estimating the future impact of capital expenditures associated with system expansion. RPP excludes customers attaching to existing mains (infill services). RPP is required to achieve a PI threshold greater than 1.0.

The OEB's view, as set out in *EBO 188*, is that by assessing the financial viability of all potential customers as a group (using a portfolio approach), more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.

A feasibility analysis determines whether or not a project meets financial requirements and ensures there is no undue subsidization in the rates charged by EGD. This is accomplished by evaluating future revenues the project will generate versus the costs of the project.

The Profitability Index is a ratio of a project's revenues against its costs. PI = 1.0 represents the value of a project's revenues being equal to the project's costs. This means that over the life of the project, project revenues will cover the entire project cost, ensuring the project will be economically feasible.

The OEB, through *EBO 188*, expects utilities to maintain a PI of 1.0 or greater for their total project portfolio. Each project must meet a PI of at least 0.8 to minimize cross-subsidization among customers across all projects. This ensures project costs are recovered from customers that directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers.

Feasibility Process: When evaluating a new project, EGD prepares a forecast of project costs and revenues. An EGD field representative will visit the project site to determine the project requirements and costs, number of potential customers, and the anticipated natural gas consumption. Project revenues will be calculated based on the estimated number of new customers and their estimated annual natural gas consumption over a 40-year period (for residential and commercial customers) or a 20-year period (for large volume customers).

EGD determines project feasibility using forecasted project costs and revenues - if the present value of project revenues is equal to or greater than the present value of project costs, the project is economically feasible and can proceed to be built. In such a case, over the life of the project, revenues will recover the entire cost of the project. Depending on the size of a project, EGD may be required to go through a Leave to Construct (LTC) application process with the OEB to determine if the project can be built. In some instances, the OEB may approve a project with the requirement that EGD meet certain conditions.

When the present value of revenues is less than the present value of costs, customers will be asked to pay a Contribution In Aid of Construction (CIAC) amount. The CIAC is the amount by which project costs must be reduced by the customer so the project is feasible (i.e., brought to the required PI level). In the absence of charging a CIAC amount, the utility collects less revenue than is necessary to fund the project and as such creates a revenue deficiency. This revenue deficiency would then have to be recovered from other customers, essentially increasing rates for other customers.

The OEB recognizes that the amount charged as a CIAC is project-specific and varies depending on the costs and revenues for each project. Based on this, the OEB has established feasibility guidelines and a formula for calculating the CIAC. Utilities can only charge a CIAC as prescribed by the OEB in *EBO 188*. If the customer chooses not to pay, the project is not built.

Feasibility Formula:

$$\text{Profitability Index (PI)} = \frac{\sum \text{PV (Revenue} - \text{O\&M} + \text{CCA Tax Shield)}}{\sum \text{PV of Capital Cost}} \text{ or PI} = \frac{\text{Benefits}}{\text{Cost}}$$

Benefits: The project revenues are the monthly customer charges and delivery charges that EGD will bill the customer.

For subdivision and residential connections, consumption is estimated based on building type (single, semi-detached, townhouse) and configuration (bungalow, split, or two-storey) in conjunction with the load information provided by the builder. EGD calculates customer revenue based on consumption levels input by the Customer Connections representative.

A load sheet is used to estimate consumption of commercial and industrial connections. The load sheet information is provided by the customer and contains consumption of various appliances installed at the premises.

Costs: Direct capital costs for a project include materials (pipe, couplings, meter sets, etc.), labour and equipment to install or construct the project, reinstatement of the surface (such as road, sidewalk, landscaping), and the ongoing operation and maintenance of the project.

Indirect costs for a project include the costs of support groups (such as Customer Connections, Construction, Network Planning, and Land) that facilitate the connection process, gas distribution network planning costs which support new load growth, drafting activities, and administration costs attributable to customer growth such as inventory management.

5.1.3 Customer Growth Strategy Overview

CONDITION	RISK / OPPORTUNITY	STRATEGY
Between 2007 and 2017, EGD's customer growth was approximately 35,000 customers per year. In 2018, EGD expects to add approximately 31,700 new customers. Between 2018 and 2028, EGD's customer growth is forecasted to be approximately 30,100 customers per year on average.	EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers (*EBO 188*), where feasibility is quantified by determining the value of a project's revenues against its costs (the Profitability Index or PI).	The strategy for the Customer Growth asset class is to ensure that required infrastructure is installed to enable the addition of all forecasted customers that are feasible under *EBO 188* guidelines. EGD continues to monitor and update the customer additions forecast through the annual Long Range Planning process.

5.1.4 Customer Growth Forecast

The customer growth forecast has been developed using a number of sources. Information considered in developing this forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. EGD has been consistently using this approach, which was approved by the OEB in previous rate applications.

There are important data considerations using this approach. For instance, a primary data source used in predicting growth is historical housing starts from Canadian Mortgage and Housing Corporation. For growth projections particularly in the apartment sector, housing starts are much higher than the customer additions in the sector. Although housing starts in the apartment sector comprise approximately 50% of total housing starts in 2017, this does not translate to 50% new customer additions in the apartment sector. This is because one apartment building is usually counted as one customer while housing starts statistics are counted on the basis of housing units.

The Customer Connections group provides further inputs based on known applications and development projects. A consolidation of forecasts and known projects are used to determine the final customer growth forecast.

Based on this customer growth forecast methodology, a 2018 Long Range Plan was developed over 10 years. This forecast is summarized in **Figure 5.1-3**, which represents the forecasted number of customers' additions over 10 years by area.

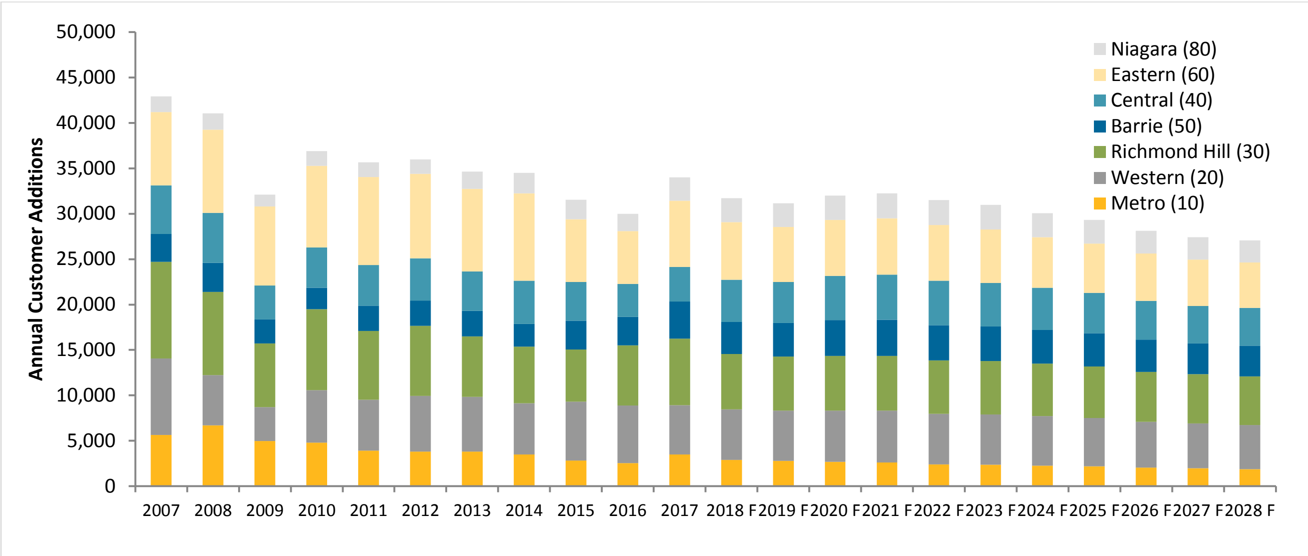


Figure 5.1-3: Historical and 10-Year Forecast Customer Growth

Between 2007 and 2017, EGD's customer growth was approximately 35,000 per year. In 2018, EGD expects to add approximately 31,700 new customers. Between 2018 and 2028, EGD's customer growth is forecasted to be approximately 30,100 customers per year on average. Key insights relating to the customer growth forecast:

- Relative to 2017, housing starts are projected to remain flat in the short term and slightly decline thereafter.
- Due to increasing scarcity of land supply and the associated increase in housing prices in EGD's franchise areas (particularly in the GTA) non-apartment housing starts in the area have seen a decline.
- Urban density in EGD's franchise areas is reflected in the fact that apartments have been accounting for a larger share of total housing starts. Given that one building counts as a single customer because of the use of bulk meters, lower customer additions do not reflect lower loads served, but simply a shift in the makeup of the sectoral source of growth. Steady residential growth in the new construction sector is reflected in the strong additions in areas covering the GTA, which includes the regions of Peel and York.
- Replacement (conversion to natural gas) customers have been declining over the last six years and this trend is expected to continue as demonstrated in **Figure 5.1-4.**

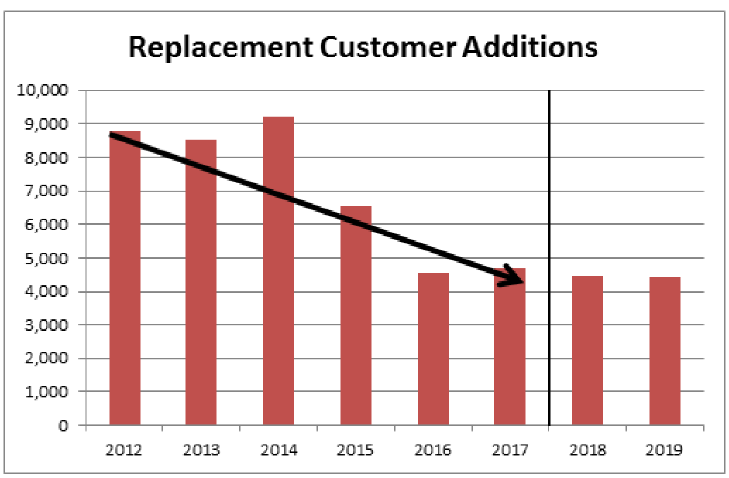


Figure 5.1-4: Replacement Customer Additions

Based on the customer growth forecast methodology described in the previous section, **Figure 5.1-5** represents the forecasted number of customers over 10 years by sector.

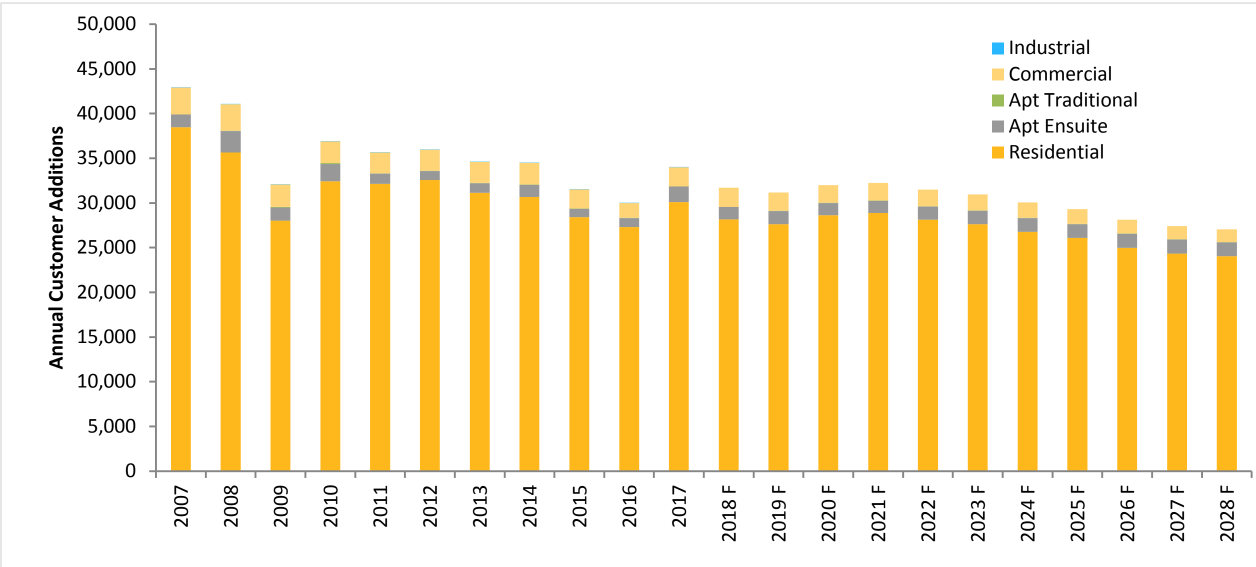


Figure 5.1-5: Historical and 10-Year Forecast Growth by Sector

The customer additions by sector reflect continued residential growth over the forecast period in both the residential subdivision and residential replacement (conversion) markets, accounting for over 90% of customer additions growth. The commercial sector constitutes over 6% of customer additions growth, with apartment and industrial customers constituting the balance.

Figure 5.1-6 represents the forecasted breakdown of anticipated customer additions over the next 10 years by EGD operating region.

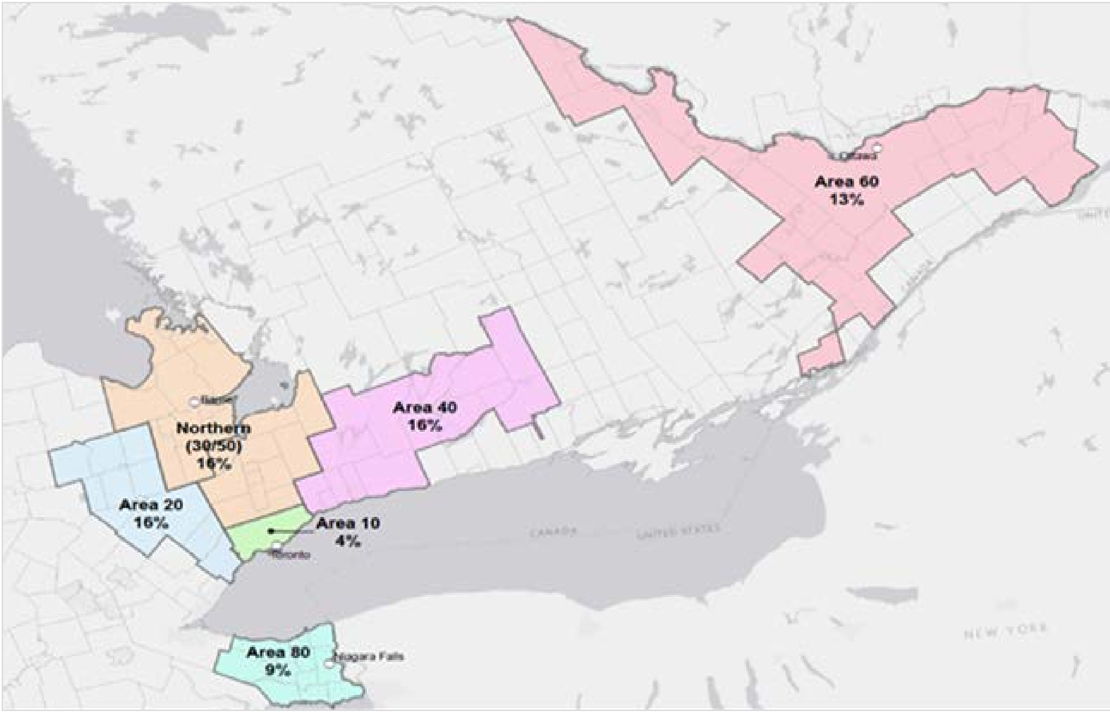


Figure 5.1-6: Growth Forecast 2019 to 2028

5.1.5 Customer Growth Capital Expenditure Forecasting Methodology

Customer Growth capital expenditure requirements includes the direct costs associated with the material and installation of mains, services, and regulator stations. Installation costs of the meter(s) are included as part of the direct capital cost within the Customer Growth budget, however, the cost of the metering equipment/instrumentation is accounted for in the Customer Assets asset class.

The Customer Growth capital expenditure required to facilitate the connection of new gas customers include:

- Attachments from residential subdivision
- Residential replacement (fuel conversions of existing homes)
- Commercial buildings
- Apartment buildings (both individually metered units (ensuite) and single meters per building)
- Industrial facilities

5.1.5.1 Methodology

One of the key drivers of Customer Growth capital requirements is the historical spend profile in each area. Capital spend is not uniform across all areas, as some areas have inherently higher costs (e.g., hard rock, type of joint trench agreements, densely populated areas, and type of customers predominantly being attached). Based on the historical spend in each area containing unique characteristics, combined with forecast customer additions and inflation, the 10-year capital expenditure forecast was determined. The capital requirement includes an allowance for some localized main extensions and operational considerations.

5.1.5.2 Other Capital Cost Considerations

Material and labour costs will be influenced by the customer mix between market sectors such as residential versus commercial or industrial - residential customers require smaller sized distribution infrastructure (compared to commercial or industrial customers) and are usually installed in joint trenches.

Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%.

Construction labour costs are influenced by ground cover and land use. For example, the labour costs associated with new subdivision or greenfield construction are substantially lower than built-up urban construction. Greenfield developments are in open fields or land where there is minimal traffic and congestion, generally requiring little or no cleanup or restoration, while urban construction requires traffic control, working in congested urban areas with extensive pavement and sidewalk excavation and restoration, along with congested underground infrastructure.

The need to locate and excavate in the vicinity of existing live gas plant is a necessary requirement when installing customer growth infrastructure, particularly in built-up urban areas within EGD franchise areas. The TSSA and the Electrical Safety Authority (ESA) have issued *Guidelines for Excavation in the Vicinity of Utility Lines*, describing locates requirements and 'hand excavation' within 0.3 meters of natural gas pipelines, rather than mechanical excavation methods. An approved alternate to hand excavations is the use of hydro-excavation equipment to expose buried natural gas pipelines, primarily to protect the worker from damaging the infrastructure. To ensure compliance, hydro-excavation is the preferred construction method for EGD contractors. Additional costs for third-party hydro-excavation contractors and scheduling and utilization of specialized equipment are managed within Customer Growth capital requirements.

Residential developers, particularly around the GTA, are continuing to get an early start on construction in recent years, commencing their land development activities in the winter months. This requires EGD to increasingly construct new construction infrastructure during the winter months as well, necessitating the payment of a "winter premium" to contractors. The winter premium is paid to compensate contractors for the additional effort required to construct during winter, including snow removal, excavation through frost, etc. The incremental costs for winter construction must also be offset with new construction methods and technologies. An example of this in practice is the pre-installation of road crossing pipe in new subdivisions prior to winter, eliminating the requirement to bore or excavate under new roads being built in these areas.

The increased municipal and conservation authority requirements for the protection of the natural environment (including trees, wetlands, and environmentally sensitive areas) has necessitated the increased use of trenchless technology or boring to lessen the impact on these features. The additional costs required to install pipelines and facilities in these areas necessitates alternate construction methods as well as planning and changes to design standards to avoid or mitigate the impact of construction on these features.

Construction techniques, technologies, and practices are continuously tested, evaluated, and implemented at EGD to improve safety, efficiency, and quality. Joint utility trench (JUT) construction is one method that is used extensively in subdivisions or greenfield projects. JUT involves the excavation of a single trench that has a customized profile and is used for the installation of gas, electric, and telecommunications infrastructure. The customized profile provides for compliant separation and depth of cover for the various individual utilities. The JUT contractors will excavate the trench, install the various pipes and cables to their respective specifications, and backfill the excavation. The installation of the various utilities within a single excavation provides labour savings, and also eliminates the need to excavate around hydro and other utilities at different times, minimizing the potential for third-party excavation damages. EGD utilizes JUT extensively in many operating areas for subdivision mains and services.

Additionally, EGD continues to establish long-term contracts with its construction contractors to stabilize and reduce costs.

5.1.6 Strategy

The strategy for the Customer Growth asset class is to ensure that required infrastructure is installed to enable the addition of all forecasted customers that are feasible under *EBO 188* guidelines. EGD continues to monitor and update the customer additions forecast through the annual Long Range Planning process. EGD continues to evaluate the scope of its Carbon Strategy and subsequent impact on customer growth forecasts, based on the outcomes of the IRP study.

5.1.7 Customer Growth Capital Expenditure Summary

Customer Growth Capital Summary

The Customer Growth asset class organizes the proposed spending programmatically by sector: residential, commercial, and industrial. The total proposed capital expenditure accounts to $1B from 2019 to 2028, as summarized in **Table 5.1-3.** The Customer Growth capital is further summarized as part of EGD's total 10-year capital plan in **Section 6**.

Table 5.1-3: Customer Growth Capital Summary ($ Thousands)

Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-year Forecast
Commercial	22,946	23,804	24,304	24,049	24,027	23,710	23,500	22,932	22,731	22,757	234,761
Industrial	3,763	3,903	3,985	3,943	3,940	3,888	3,853	3,760	3,727	3,732	38,494
Residential	72,126	74,823	76,393	75,593	75,524	74,528	73,866	72,083	71,451	71,532	737,919
Total	**98,835**	**102,530**	**104,681**	**103,585**	**103,491**	**102,126**	**101,219**	**98,775**	**97,909**	**98,021**	**1,011,174**

5.2 PIPE

Distribution piping includes EGD-owned and maintained piping including pipe, valves, all pipe appurtenances, services, and risers installed up to Customer Asset components and upstream of the meter. Distribution piping can be located inside or outside of a building.

EGD's gas distribution system operates at several pressure classes and uses various specifications and materials to achieve the safe and reliable delivery of natural gas to customers. Pipe is the connection between the entry of natural gas into EGD's system and the delivery of gas to where energy is used by customers.

5.2.1 Pipe Objectives

The Pipe asset class includes mains, services, risers, and valves. Mains are categorized into Integrity Mains (steel only) or Distribution Mains (steel and plastic). Services are categorized by material type - steel, plastic, or copper. Risers are categorized by material type - copper, steel, anodeless, and plastic with conduit. The asset subclass breakdown is illustrated in **Figure 5.2-1**.

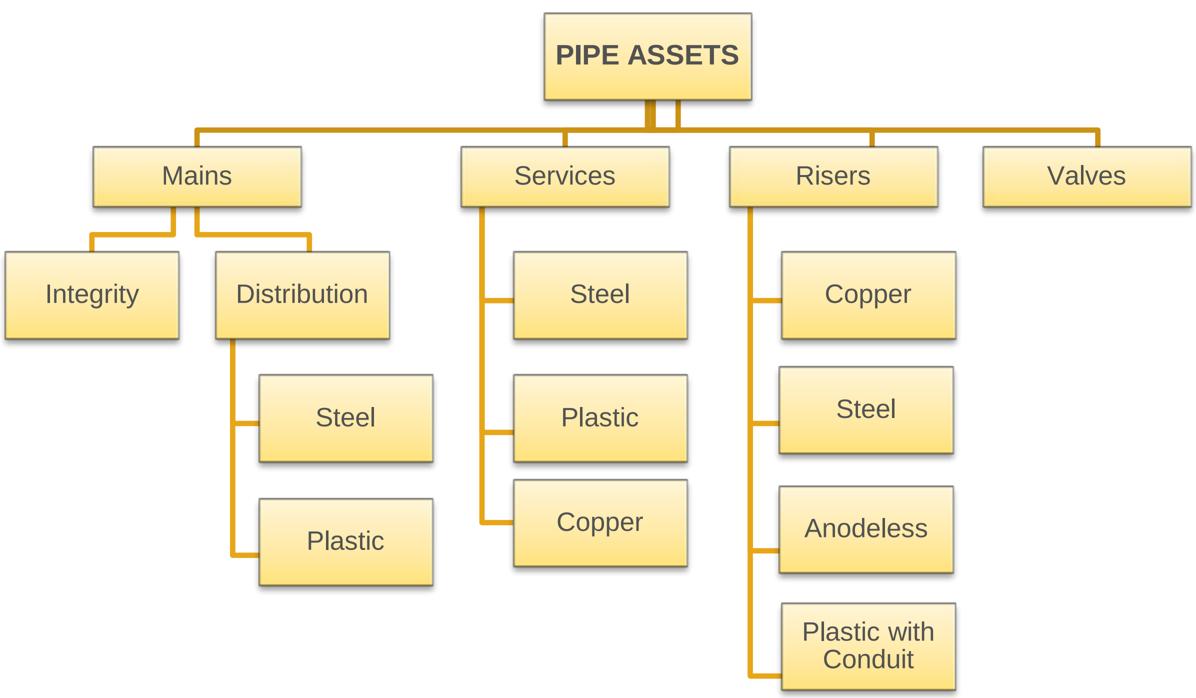


Figure 5.2-1: Pipe Asset Classification

Objectives are defined for the Pipe asset class in **Table 5.2-1**.

Table 5.2-1: Pipe Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS

System Integrity and Reliability	Maintain the natural gas distribution system to meet or exceed codes, standards, and the requirements of applicable governmental authorities for safety and operational effectiveness.	• Worker & Contractor Safety KPI
		  o QA & QC closeout rate
		  o Operator Qualification (OQ) score
		• Operating Limit Management
		  o Method of Procedure (MOP) length verified – Risk Reduction
		  o Number of Operating Limit Change Orders completed on time

	Ensure the safe and reliable delivery of natural gas to end users.	• Leak Management
		  o Completion of Annual Leak Survey Program
		  o Completion of Leak Repair Investigations
		  o Completion of River Crossing Inspections
		• Corrosion Management
		  o Percentage Above Cathodic Protection (CP)
		  o Completion of Corrosion Inspections
		  o Completion of Bridge Crossing Inspections
		• Damage Prevention
		  o Completion of aerial patrols
		  o Number of damages per 1,000 locate requests
		  o Completion of Natural Gas Sewer Safety Inspections
		• Valve Inspections
		  o Completion of annual and five-year valve inspections
		• Customer Satisfaction Survey
		  o Field Service Index

	Continuously evolve the understanding of condition and risk associated with pipe assets.	• Transmission Pipeline Condition Monitoring and Remediation
		  o Completion of Pipeline In-line Inspections
		  o Completion of immediate and scheduled Investigative digs and remediation
		• Material Fault Program
		  o On-time fault classification
		  o On-time completion of corrective actions

	Utilize cost, risk and performance information to drive asset-related decisions.	• Risk mitigated and LRROI • QRA completion percentage
	Reinforce existing distribution networks to ensure the system has the capacity to reliably meet current and future customer demand.	• Forecasted number of networks that could have low pressure issues through long range planning • Number of economically feasible customers added

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
Relocations	Relocate pipe assets to reduce or mitigate the impact of third-party work on the safe and compliant operation of the distribution system.	• Currently under development
	Recover costs allowed by municipal franchises and other agreements for relocations initiated by third parties.	• Number of past due cost recovery invoices
	Ensure pipe locations are in compliance with all governing authorities for the location of existing assets.	• Currently under development

To achieve these objectives, asset investment decisions are governed by Life Cycle Management policies presented in **Table 5.2-2**.

Table 5.2-2: Life Cycle Management for Pipe Assets

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Design the installation of pipe assets to: - Ensure the safe and reliable delivery of natural gas - Ensure worker and public safety - Ensure code compliance - Meet current and future demand requirements - Reduce risk to the lowest practicable level - Ensure critical components and systems have multiple layers of failure protection - Minimize environmental impact - Ensure components can be made safe in a reasonable period of time - Minimize future maintenance needs • Procure materials to meet or exceed applicable codes, standards, and policies. • Install pipe assets to meet or exceed codes, standards, designs, and procedures for safe and reliable operations. • Create asset records to meet or exceed standards, policies, and procedures that are traceable, verifiable, complete, and correct.
Utilize	• Operate the distribution system to: - Ensure the safe and reliable delivery of natural gas - Ensure worker and public safety - Meet or exceed compliance standards and procedures - Meet current demand - Minimize end user disruption - Utilize the assets in the most cost effective manner - Extend asset life • Monitor the performance and utilization of pipe assets to inform future life cycle decisions. • Ensure the operating pressure complies with policies, codes, and standards.
Maintain	• Maintain integrity of assets to minimize loss of containment, extend asset life and ensure compliance with codes, standards and procedures. • Maintain assets and safety controls to avoid over-pressure or delivery outages. • Maintain asset information to meet or exceed standards set out by EGD. • Determine probability and consequence of failure to inform maintenance and repair programs. • Maintain competency levels to ensure work is performed by qualified and competent workers. • Evaluate effectiveness of maintenance and inspection programs to ensure effective risk reduction to the lowest practicable level.
Renew/Retire	• Determine probability and consequence of failure to inform renewal decisions. • Develop proactive renewal programs for assets that are nearing end-of-life (informed by data and tacit knowledge and housed within the Integrity Management System). • Retire assets using a process that meets or exceeds codes and standards.

5.2.2 Pipe Inventory

The Pipe asset class is divided into four asset subclasses: mains, services, risers and valves. **Table 5.2-3** lists the inventory details for the asset class.

Table 5.2-3: Pipe Asset Class Inventory

ASSET SUBCLASS	QUANTITY
Mains (km)	**38,521**
Integrity Mains	403
Distribution Mains	38,118
Steel	12,979
Plastic	25,139
Services (#)	**2,085,631**
Copper	5,106
Steel	177,547
Plastic	1,902,978
Risers (#)	**2,034,736**
Copper	284,909
Steel	150,244
Anodeless	1,187,019
Plastic with Conduit	412,564
Valves 4” and above (#)	**11,869**
Steel	10,522
Plastic	1,347

5.2.3 Pipe Condition and Strategy Overview

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Integrity Mains		40	Integrity Management Program (IMP) mains are generally in good condition. All in-line inspection (ILI) detectable features requiring immediate mitigation and scheduled inspections are addressed within the timeline outlined in the Transmission Integrity Management Program (TIMP). Non-immediate corrosion features will be projected for future scheduled inspection or continue to be monitored through the Pipeline Integrity Management Program.	Risks identified for integrity mains: *Safety Risk:* Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *Customer Satisfaction (CSAT) Risk*: Greenhouse Gas (GHG) emissions, environmental impact, extensive customer outage, and reputational damages.	The maintenance strategy for integrity mains includes: • 7-year internal inspection • Vital Main Damage Prevention Program • Annual Leak Survey (High Consequence Areas leak surveyed semi-annually) • Cathodic Protection (CP) monitoring	EGD's replacement/renewal strategy for integrity mains is through: • **Pipeline Integrity Management Program**: Proactive program mandating ILIs on integrity main assets at seven-year inspection intervals. An Engineering Assessment using a probability approach is completed to rank pipeline anomalies, set re-inspection frequency, and repair pipeline indications as deemed necessary. Immediate or scheduled digs, repairs, and replacements are initiated as required. • **Emergency Replacement Program**: Main repairs or reactive replacements to address leaks and condition issues as identified. The approach depends on the extent of the main's poor condition. Localized poor condition is managed through pipeline repairs. Broader condition issues are managed through more extensive replacement.
Distribution Steel Mains		43	Steel mains are generally in good condition, with the exception of those found to be with inadequate CP protection or other condition issues such as reduced depth of cover due to municipal road work or specific pipeline features (e.g., blow-off valve assemblies). The population of steel mains installed in the1970s and prior (i.e., vintage steel) has been found to have varying degrees of corrosion associated with declining cathodic protection and poor coating, driving the steady increase of forecasted leak rates.	Risks identified for distribution steel mains: *Safety Risk*: Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for distribution steel mains includes: • A leak survey conducted every five years (annually for vital mains) • CP monitoring	EGD's replacement/renewal strategies to manage distribution steel mains is through: • **Corrosion Prevention Program**: Annual anode replacement program to ensure the steel main system is receiving sufficient cathodic protection. • **Relocation Program**: Relocation of pipe assets to reduce or mitigate the impact of third-party work on the safe operation of the distribution system (which can involve multiple asset subclasses). • **Emergency Replacement Program**: Main repairs or reactive replacements to address leaks and condition issues as identified. The approach depends on the extent of the main's poor condition. Localized poor condition is managed through pipeline repairs. Broader condition issues are managed through more extensive replacement. • **Major Pipeline Replacement Projects**: Material projects to manage risks of large diameter pipelines, to reduce or prevent risk from approaching the intolerable risk region. • **Distribution Steel Mains Replacement Program**: Steel main replacement program forecasted based on leak projections. Condition information is used to identify and prioritize projects. • Continuous improvement related to the development of proactive strategies to renew aging assets before reaching end-of-life.
Distribution Plastic Mains	**Plastic Mains (Pre-1977)**	43	Pre-1985 plastic mains are found to be in good condition; however, the failure curve predicts a rapid degradation over a very short period of time.	Risks identified for distribution plastic mains: *Safety Risk:* Gas leaks and migration through underground infrastructure into buildings can result in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for distribution plastic mains requires a leak survey to be conducted every five years.	EGD's replacement/renewal strategies to manage plastic mains is through: • **Emergency Replacement Program**: Main repairs or reactive replacements to address leaks and condition issues as identified. The approach depends on the extent of the main's poor condition. Localized poor condition is managed through pipeline repairs. Broader condition issues are managed through more extensive replacement. • **Vintage Plastic Main Replacement Program**: Proactive replacement program to renew aging assets (pre-1985) before reaching end-of-life. • **Relocation Program**: Relocation of pipe assets to reduce or mitigate the impact of third-party work on the safe operation of the distribution system (which can involve multiple asset subclasses). • Perform an Integrity Assessment on 1977-1985 plastic mains to understand material characteristics and failures of the asset population and determine the asset strategy.
	Plastic Mains (1977-1985)	36				
	Plastic Mains (Post-1985)	17	Post-1985 plastic mains are found to be in good condition. The materials and manufacturing processes support the longevity of this asset.			

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Distribution Services	**Steel Services**	40	Steel services are generally found to be in good condition, with the exception of those services with inadequate CP protection, where the steel services are connected to a compression style service tee, or attached to plastic mains.	Risks identified for distribution services: *Safety Risk*: Gas leaks with migration through underground infrastructure into buildings, resulting in gas accumulation and explosions. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for steel services includes: • A leak survey is conducted every five years (semi-annually for unprotected services). • CP monitoring	EGD's replacement/renewal strategies for distribution services on steel, plastic, and copper services is through: • **Service Relay Program**: Program to address leaks and condition issues as identified. Leaks on steel services are managed through temporary repairs and followed up with service relays as a permanent solution. • **Vintage Steel Replacement Program**: Proactive replacement of steel services to be completed with the Steel Mains Replacement projects. • **Vintage Plastic Replacement Program**: Proactive replacement of plastic services to be completed with the Plastic Mains Replacement projects. • **Copper Service Replacement Program**: Proactive strategy to replace remaining copper services as part of the Service Relay Program.
	Plastic Services	20	Plastic services are generally found to be in good condition.		The maintenance strategy for plastic services includes: • A leak survey is conducted every five years for pre-1985 services. • A leak survey conducted every 10 years for post-1985 services.	
	Copper Services	49	Copper services in general are failing at a rate higher than any other service type due to erosion corrosion and degradation associated with dissimilar metals at the fittings.		The maintenance strategy for copper services requires a leak survey to be conducted annually.	
Distribution Risers	**Steel Risers**	45	Steel risers are generally found to be in good condition.	Risks identified for risers: *Safety Risk*: Risk due to gas leaks with migration through underground infrastructures into buildings, resulting in gas accumulation and explosions. *Financial Risk*: Risk due to total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: Risk associated with GHG emissions, environmental impact, service interruptions, and reputational damages.	The maintenance strategy for risers includes: • Leak Survey program (frequency dependent on service material). • CP monitoring for steel risers	EGD has a reactive and proactive replacement/renewal strategy for distribution risers: • **Reactive Replacement Program**: Service relay program to replace leaking or poor condition steel, plastic-in-conduit, anodeless, and copper risers. • **Vintage Steel Main Replacement Program**: Proactive replacement of steel risers to be completed with the Steel Mains Replacement projects. • **AMP Fitting Replacement Program**: Targeted proactive replacement of high risk AMP fittings.
	Plastic-in-Conduit Risers	28	Plastic-in-conduit risers are generally found to be in good condition.			
	Anodeless Risers	13	Anodeless risers are generally found to be in good condition.			
	Copper Risers	39	Copper risers in general are failing at a rate higher than any other service due to erosion corrosion and degradation at the fittings. While the population may be in good condition, failures increase sharply when the riser approaches 50 years old.			
Valves		26	Valves are generally found to be in good condition.	Risks identified for valves: *Safety Risk*: Risk due to prolonged duration of leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and explosion. *Financial Risk*: Total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. *CSAT Risk*: GHG emissions, environmental and reputation impact, customer outages.	The maintenance strategy for valves includes: • A leak survey is conducted through the Distribution Main/Service Survey Program. • Annual Valve Inspection Program	EGD has a reactive replacement/renewal strategy for valves: **Emergency Replacement Program**: Replacement of the asset when a valve is leaking, non-functioning, or inaccessible.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
System Reinforcements	N/A	Load Gathering and Simulation, Annual Forecasting, and Long Range System Planning are completed and areas have been identified requiring reinforcement.	Ensure security of gas supply to existing customers and support forecasted customer growth using the guidelines of *EBO 188*.	N/A	EGD’s replacement/renewal strategy for system reinforcements is through the **Reinforcement Program**, which mandates the reinforcement of pipeline networks identified by the distribution System Long Range Plan (which can involve multiple asset subclasses).

5.2.4 Integrity Mains

Integrity Management Program (IMP) mains are managed through the Transmission Integrity Management Program (TIMP). The TIMP is a continuous improvement program based on Plan-Do-Check-Act principles as defined in *CSA Z662-11 Annex N*. IMP mains are all pipelines operating at stress levels of 30% Specified Minimum Yield Strength (SMYS) and greater, and targeted Vital Mains[7] that operate at stress levels less than 30% SMYS. These pipelines (approximately 403 km in total length) account for less than 1% of all mains in EGD's distribution network and are managed as transmission mains (rather than distribution mains) as per TSSA requirements.

Figure 5.2-2 presents the number of kilometers of IMP mains by calendar age, illustrating a wide distribution of age for this group of assets. Over 42% (172 km) of these assets are more than 50 years old.

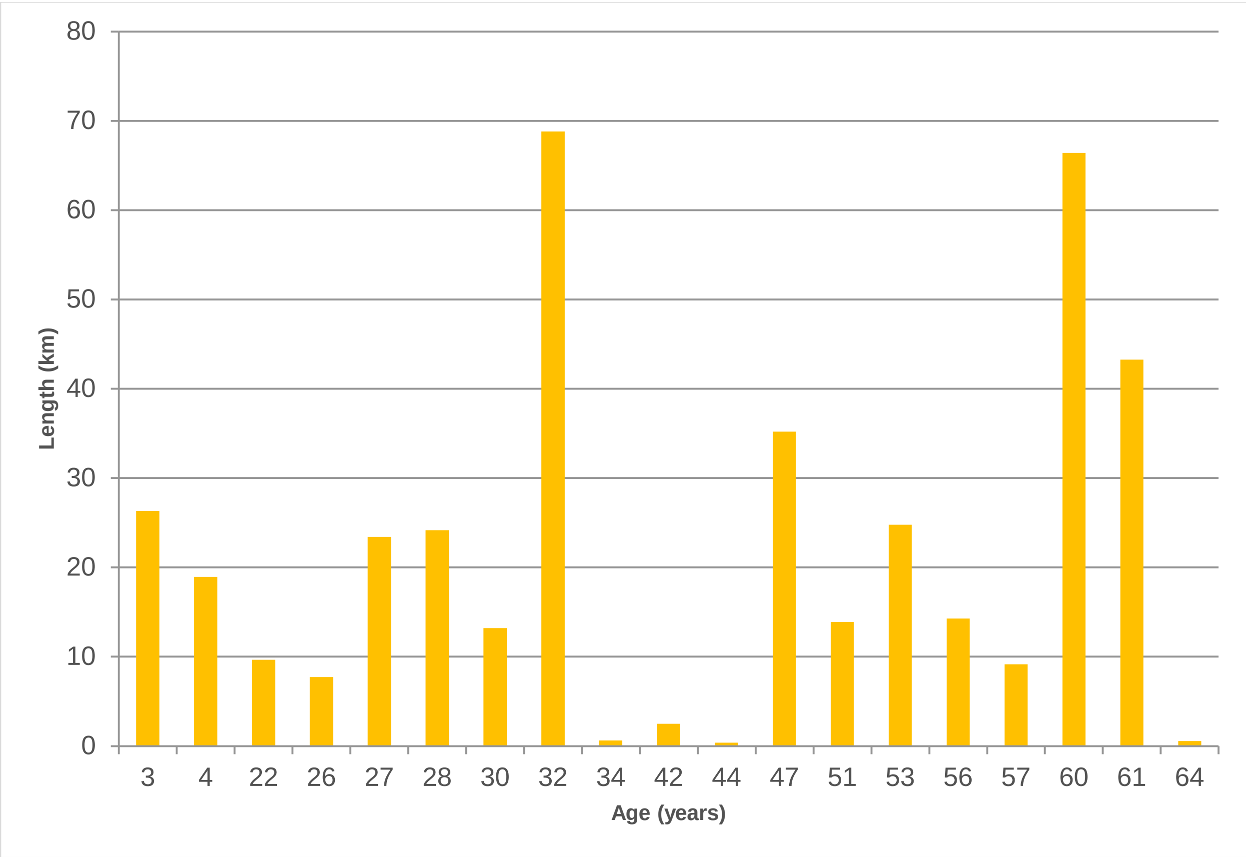


Figure 5.2-2: Integrity Mains Age Distribution

5.2.4.1 Condition Methodology

The Gas Storage and Transmission System (GSTS) Integrity department manages pipelines under the TIMP. The program requires re-inspection of Integrity mains (also referred to as IMP mains) at seven-year intervals, unless an Engineering Assessment using a probability approach is completed to rank pipeline anomalies and to reset the inspection frequency. The TIMP also harmonizes pipeline inspection schedules to distribute operational costs and resource requirements, enabling stable, long-term operational budgets and leveling resource demands to perform inspections. The TIMP includes operating programs that monitor threats to pipe assets, including:

[7] Vital mains consist of NEB regulated pipelines, IMP pipelines, and select distribution mains. These mains are critical to the safe and reliable operations of the gas distribution system

- External corrosion
- Internal corrosion
- Internal erosion
- Manufacturing-related defects
- Welding/fabrication-related defects
- Equipment failure
- Weather-related threats
- Third party/mechanical damage
- Stress Corrosion Cracking
- Outside forces
- Incorrect operating procedures

The TIMP is a systematic process for continually assessing and remediating the integrity of pipeline systems through prevention, detection, and mitigation techniques, accomplished by compiling and analyzing data in a comprehensive and iterative manner. Risk assessments are used by pipeline operators and regulators to analyze data in support of integrity management programs. At EGD, risk assessment methods are used to identify and understand threat mechanisms and the likelihood and consequences of failure, facilitating pipeline integrity management activities and optimizing the use of resources to control risk.

The TIMP employs a reliability-based process, using risk analysis as a tool for developing and prioritizing pipeline maintenance on pipeline features such as corrosion, cracks, mechanical damage, manufacturing defects. These issues are identified during in-line inspections (ILI) and direct assessment of exposed pipeline sections (through excavation and inspection using non-destructive test (NDT) methods.

To measure the progression of pipeline features, baseline ILI inspections are completed to identify manufacturing and construction defects. The baseline is then used to assess future corrosion for successive inspections and fitness-for-service assessments.

Pipeline defects found during a direct assessment are repaired before backfilling the exposed pipe. Any features (such as corrosion, cracks, mechanical damage, and manufacturing defects) found during an ILI are classified as requiring immediate action, scheduled for investigation, or monitored in accordance with EGD's policies. These policies were developed based on applicable codes, regulations, standards, and industry best practices, and tailored to prevent the loss of containment.

The TIMP reduces the probability of loss of containment through the ILI and assessment process by remediating detected critical pipeline anomalies. For less significant anomalies, in-ditch inspections are scheduled at a future date. Computer modeling is used to forecast corrosion growth rate to determine when inspection and repairs are required in the future. This approach relies on the use of accurate and complete data, and a deep understanding of the data set.

5.2.4.2 Condition Findings

EGD has implemented the Pipeline Risk and Integrity Management (PRIM) program within TIMP for ILI data analysis and risk assessment of IMP pipeline features. Using corrosion growth modeling, all known corrosion features of the IMP pipelines are projected from the last ILI date to future years. The forecasted number of scheduled inspection digs is listed in **Table 5.2-4**:

Table 5.2-4: Estimated Number of Inspection Digs

YEAR	APPROXIMATE NUMBER OF PROJECTED FEATURES	APPROXIMATE NUMBER OF DIGS /YEAR
2022-2026	52	11
2027-2031	63	13
2032-2036	94	19
2037-2041	99	20

As most of the IMP pipelines have been inspected twice since the inception of the Integrity Management Program, corrosion features requiring mitigation have been addressed within the timeline set out in the program. This explains the steady level of forecasted inspection digs over the next 10 years, with an average of 11 to 13 digs per year.

5.2.4.3 Risk and Opportunity

Integrity mains are critical infrastructure forming the backbone of the distribution system. Integrity mains directly supply large industrial customers (including natural gas-fired power plants), are primarily located in urban areas, and pass through many High Consequence Areas (HCAs). Any pipeline defects resulting in a gas release in these areas would require a substantial emergency response and a temporary shutdown of the pipeline. Consequences could be severe as pipeline failures, posing a public safety and gas supply reliability risk.

EGD has classified the risks and consequences associated with potential failures on these assets into three categories: safety, financial, and customer satisfaction. A safety risk can be due to a major gas leak or pipe rupture as Integrity mains operate at a higher pressure. Gas migration through underground infrastructure and into buildings can result in gas accumulation and explosion. A financial risk can be due to repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused the escape of gas. Customer satisfaction risk associated with pipeline failure includes GHG emissions, environmental impact, extensive customer outages, and reputational damages.

The risks associated with these mains are mitigated through the TIMP, using internal ILI inspections and external direct assessments. These inspections assist EGD in identifying whether a pipeline is fit for service and provide quantitative data that can be used to forecast the expected life of the asset and make informed decisions on service life extensions. To validate the accuracy of the ILI data, EGD conducts Integrity digs to perform NDTs on targeted mains.

By mitigating immediate and scheduled pipeline features and targeting monitored features, the TIMP reduces the probability of pipeline failures, reducing the overall public risk and ensuring reliable gas supply.

5.2.4.4 Strategy

The strategy to address the risk associated with Integrity mains is to continue ILIs at the current seven-year frequency, unless an Engineering Assessment utilizing a probability approach is completed to rank pipeline anomalies, set re-inspection frequency, and repair pipeline indications as deemed necessary.

Safety is the primary driver for the Integrity Mains ILI program, which uses a strategic, long-term risk mitigation approach to ensure these assets remain fit for service. Data acquired from inspections allows EGD to assess the health of the system and helps to ensure pipeline safety.

The continuation of the ILI program as an approach contributes to system longevity and is used to manage the balance between pipeline repairs and full replacement.

The scheduled inspections through the ILI program reduce the probability of Integrity main failures and prevent large scale customer interruptions or uncontrolled gas releases

EGD continues to manage IMP pipelines through the ILI program, repairing or replacing the pipeline when risk limits are breached. Pipeline program management is evaluated on a continual basis using Plan-Do-Check-Act methodology. When analysis indicates repair costs exceed capital requirements to replace the asset, the mitigation strategy will be evaluated to ensure that risk is managed to the lowest practicable level.

Emergency Replacement Program

The Emergency Replacement program addresses unforeseen pipeline emergencies that are small in nature. Examples of these types of jobs include cutting out a leaking section of main/fitting, removing blow-offs that require immediate attention, ongoing municipal work that encounters an unexpected gas plant - catch basin placements, structures, temporary main cut-out to access municipal plant - water mains etc.

5.2.5 Distribution Steel Mains

Distribution steel mains, managed through the Distribution Integrity Management Program (DIMP) are an integral asset of EGD's natural gas distribution system. The steel pipeline system (approximately 13,000 km) accounts for approximately 34% of all mains within the gas distribution system and includes critical infrastructure from gate stations to lower pressure systems. Between the early 1950s and early 1970s, steel mains were the only material used in the gas distribution system. These mains operate at different pressure classes, from Low Pressure to Extra-High Pressure, and range in size from one inch to 36 inches in diameter. **Figure 5.2-3** illustrates the calendar age of the steel main population. Note that distribution steel mains do not include IMP steel mains.

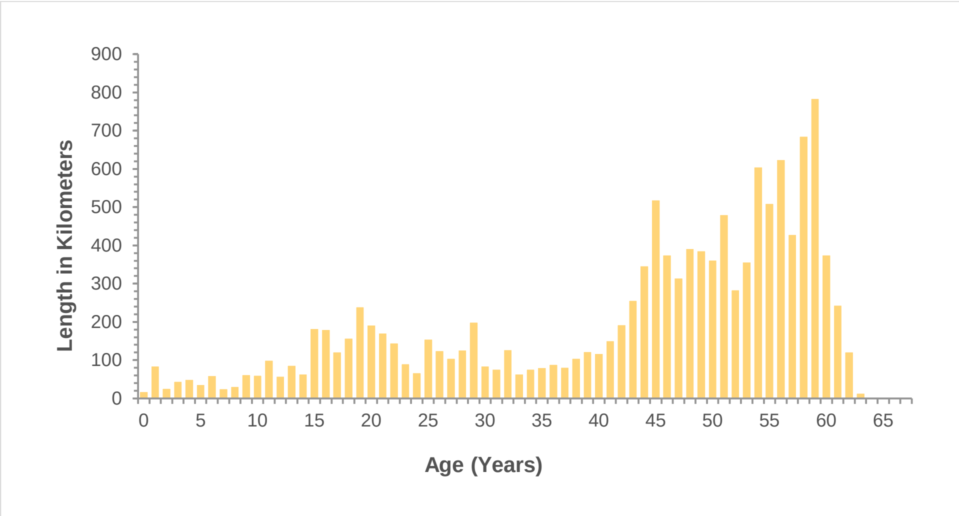


Figure 5.2-3: Steel Main Age Distribution (2017 Base Year)

Figure 5.2-3 shows a greater length of steel mains increasing with age. This is due to a major system expansion from the mid-1950s to early 1970s, when steel mains were installed at an average of 440 kilometers per year. Vintage steel mains (steel mains installed 1970s and prior) account for over 50% (more than 7,000 kilometers) of the total steel mains population. These mains were installed using material, coatings, design requirements, and construction practices based on standards during that time. Similarly, protection programs such as utility locate and cathodic protection procedures were different from current practices.

Distribution steel mains service some of the oldest and most populated parts of the EGD franchise area, including the downtown cores of Toronto and Ottawa. Over time, urban encroachment and infrastructure activities supporting municipal growth have impacted the conditions and consequences associated with potential asset failure. In urban areas, challenges exist in ensuring adequate cathodic protection due to interference from subway, streetcar and light-rail transit systems.

5.2.5.1 Condition Methodology

The condition of distribution steel mains assets are determined through:

- **Maintenance programs**: These programs (such as leak survey and cathodic protection) monitor asset conditions and restore assets to their functional state.
- **Condition assessment programs**: These programs (such as distribution system Integrity Assessment and material fault reporting) identify and assess failure mechanisms of EGD's assets.
- **Tacit knowledge (SMA/Worker input)**: Through regular meetings with SMAs, field knowledge is utilized to identify potential condition issues.
- **Leak projection modelling**: One of the major threats to steel mains is corrosion. A leak projection model accounting for pipe attributes has been developed through the Asset Health Review to forecast the number of corrosion leaks based on statistical analysis of corrosion leak history from the past ten years.

5.2.5.2 Condition Findings

Based on the condition assessment methodologies outlined in the previous section, **Table 5.2-5** outlines the condition findings associated with distribution steel mains. These findings are mainly associated with vintage steel mains.

Table 5.2-5: Condition Issues Identified

ISSUE	DESCRIPTION
Corrosion	Over time, coating degradation and poor cathodic protection can cause corrosion, resulting in wall loss. Some examples are: vintage steel mains and isolated steel mains or headers.
Compression Couplings: Pull Out	Compression couplings (mechanical fittings not welded onto the main) that are not properly restrained could cause a loss of containment due to exposed points of thrust. Compression couplings are held in place by the weight of the soil. When the soil is disturbed, the pipe can pull out of the fitting, resulting in gas escaping through the open pipe end. Some vintage gas mains (such as the Kipling Oshawa Loop (KOL) main) do not have sufficient records identifying the existence and location of these fittings. EGD has mitigation practices in place to address existing known compression couplings.
Compression Couplings: Corrosion	Compression couplings on steel mains that are unknowingly isolated from the corrosion protection system could result in inadequate cathodic protection, leading to the assets' accelerated corrosion and potentially loss of containment.
Shallow Blow-off Valves	Shallow blow-off valve assemblies could be damaged during excavation activities (see **Figure 5.2-4**).
Depth of Cover	Reduction in the original depth of cover due to urban development could increase the potential damages due to excavation activities and increased external loading. A minimum depth of cover is needed to ensure the maximum weight of vehicles traversing across pipelines is not exceeded. If the depth of cover is not appropriate, the pipe experiences excessive stress and failures could result (see **Figure 5.2-5**).
Bridge crossing: Corrosion	Continuous exposure to road salt and seasonal ground movement on bridge crossing assets could result in accelerated corrosion and external loading/stresses (see **Figure 5.2-6)**.
Pipe Casing: Corrosion	Lack of cathodic protection on pipe casings could result in corrosion, causing excessive stress or shorts on the carrier pipe in contact with the casing, which could lead to the loss of containment.
Seam Welds	Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion (**Figure 5.2-7**and **Figure 5.2-8**).
Steel Drips: Third Party Damage	Steel drips with a protruding drip rod that extends vertically from the main to centimeters of grade are susceptible to damage during excavation activities (**Figure 5.2-9**).
Latent Third Party Damage	Latent damages to pipe coatings that were never reported to EGD for repair and became active corrosion sites could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment. (**Figure 5.2-10**)

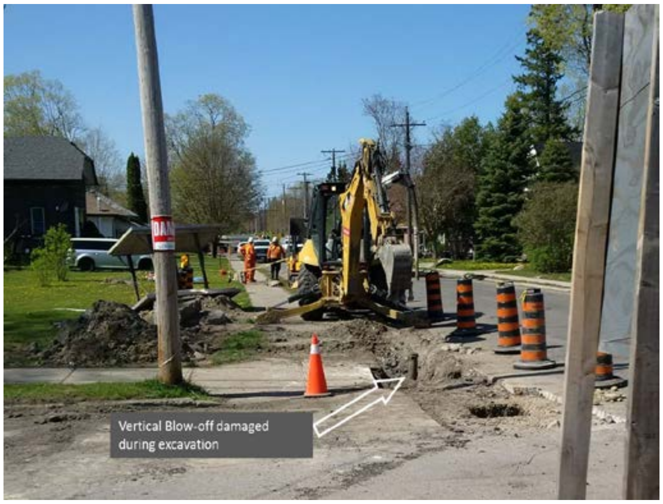


Figure 5.2-4: A Shallow Vertical Blow-off Assembly Damaged during Excavation

Figure 5.2-5: Shallow and Embedded Gas Main due to Road Grade Change

Figure 5.2-6: Severe corrosion on Bridge Crossing Pipe

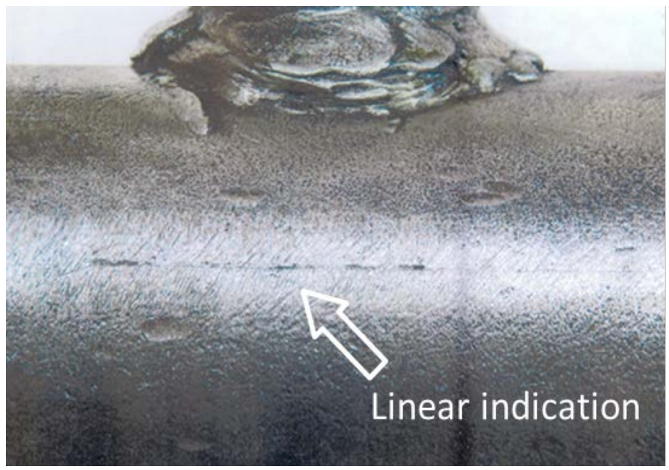


Figure 5.2-7: Vintage NPS 2 Steel Main with Linear Indication along Weld Seam

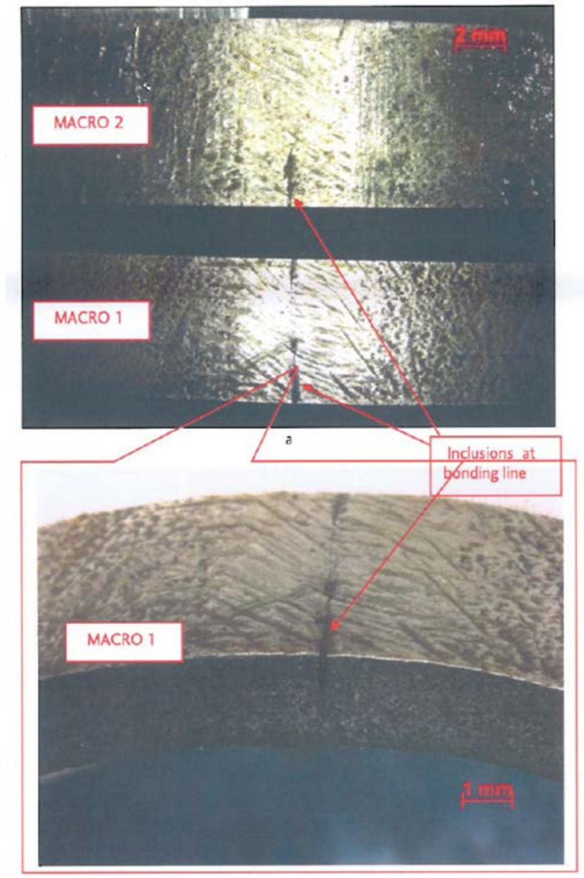


Figure 5.2-8: Inclusion at Pipe Weld Seam on Vintage NPS 2 Gas Main

Figure 5.2-9: Damaged Drip Rod on Vintage NPS 2 Gas Main

Figure 5.2-10: Long Section of NPS 12 Gas Main Exposed at Major Construction Site in Toronto

Failure history for the steel main population is shown in **Figure 5.2-11**.

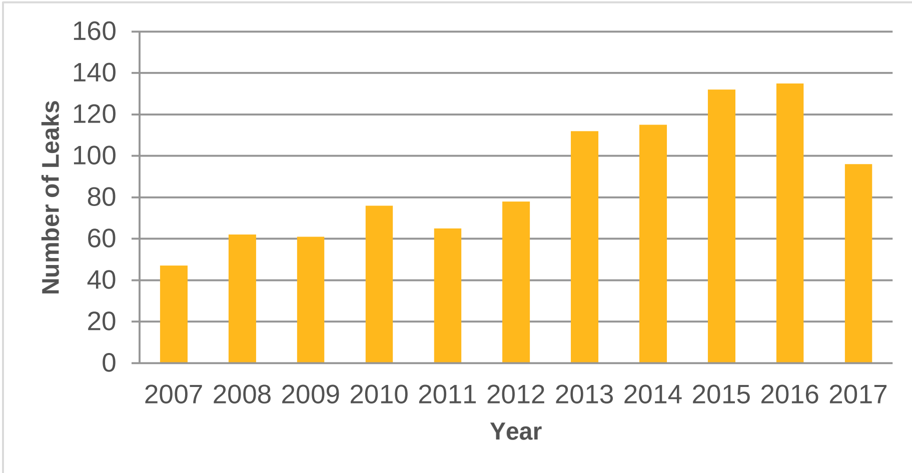


Figure 5.2-11: Historical Steel Main Leaks

It can be seen in the failure history that leaks (defined as a loss of containment for steel mains) are on an upward trend over the last 11 years. Irregularities are explained by the five-year leak survey cycle where steel mains are geographically divided into groups to be surveyed every five years, with older steel mains potentially falling into specific survey years, resulting in a cyclical leak profile instead of a gradual increase over time.

By applying a leak projection model, the annual number of leaks on distribution steel mains over the timeframe of the current Asset Management Plan and the next 40 years was developed to understand the potential impact to EGD businesses (see **Figure 5.2-12** and **Figure 5.2-13)**.

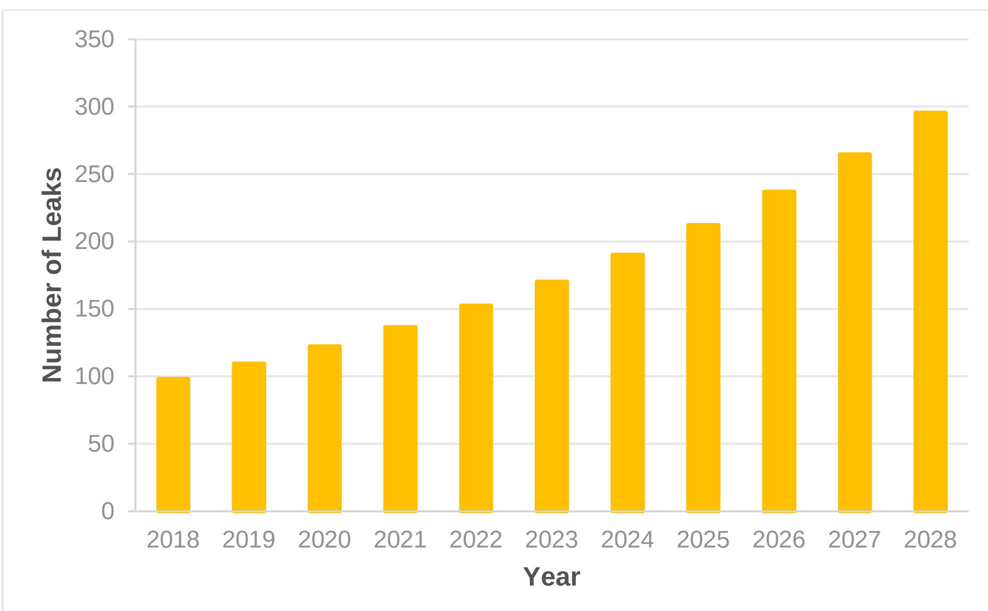


Figure 5.2-12: Steel Mains Leak Projections (2018-2028)

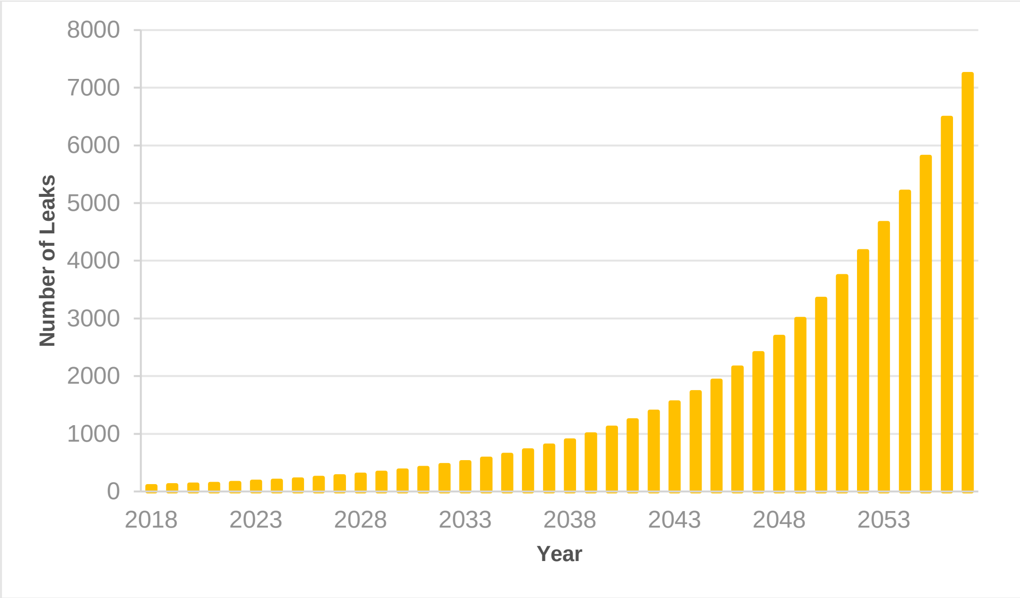


Figure 5.2-13: Steel Mains Leak Projections (2017-2057)

Both projections assume no change to EGD's current maintenance practices. Most steel main leaks are mitigated by repairs, and a small number is mitigated through targeted mains replacement. The steel main leak projection model forecasts a steady leak increase over the next 10 years (see **Figure 5.2-12)**. The annual leak rate is expected to triple by the year 2028. When steel main leaks are projected over the next 40 years (see **Figure 5.2-13)**, the number of leaks increases exponentially.

The significant increase in leaks is forecasted to take place between the years 2037 and 2057, when the oldest vintage steel mains will be approaching 100 years old. This sharp increase in leak rate could be due to various factors, such as multiple coating defects along the pipe body and poor CP history. Coating defects can result from manufacturing defects, field applied coating anomalies, coating degradation, or third party damage.

To further verify the validity of the leak projection model, corrosion rates of steel mains were analyzed based on ILI data from IMP mains. It was estimated that the majority of distribution steel mains could potentially experience at least one corrosion leak before reaching 100 years old, consistent with the result from the steel main leak projection model. Some steel mains could experience more severe corrosion due to exposure to multiple influencing factors, such as coating damages, poor cathodic protection and aggressive soil/ground condition, leaks could occur well before the age of 100. Therefore, a main replacement would be considered instead of a repair.

For instance, **Figure 5.2-14** and **Figure 5.2-15** show a recent leak repair on a 12-inch vintage steel main located in downtown Toronto. This steel main was installed in the 1960s, when construction practices allowed for the use of mechanical fittings (compression couplings) to join gas mains together.

Figure 5.2-14: Leak Investigation on Vintage NPS 12 Gas Main

Figure 5.2-15:Shallow and Embedded Gas Main due to Road Grade Change

The standard pipe coating applied gets brittle over time and is susceptible to cracking and disbondment, allowing for corrosion to occur. Combined with construction activities in close proximity over the years and potential stray current from the streetcar tracks running parallel to the main, multiple leaks developed in a short time (see **Figure 5.2-15** and **Figure 5.2-16**). This type of pipe design and installation is considered to be typical among vintage steel mains.

Figure 5.2-16: Multiple Leaks due to Severe Corrosion on Vintage NPS 12 Gas Main

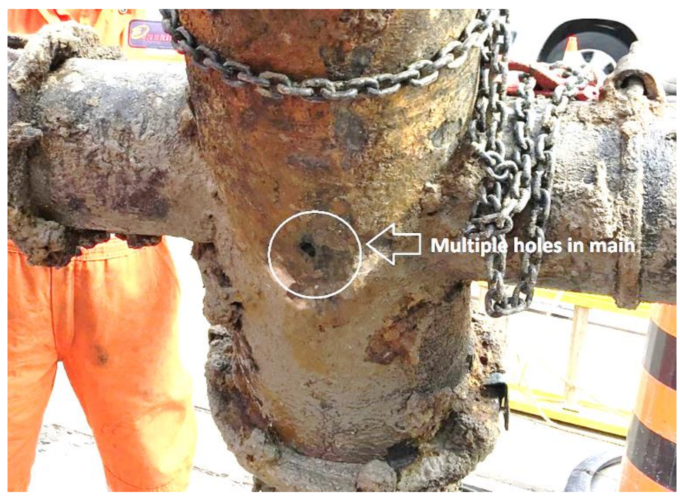


Figure 5.2-17: Multiple Leaks on Vintage NPS 12 Gas Main

For this reason, EGD continues to monitor the asset health of steel mains, update its models with best available information and determine appropriate mitigating action.

Through direct assessments and observations made during steel main repairs and other maintenance activities, vintage steel mains have demonstrated faster declining health compared to steel mains installed after the 1970s. This is attributed to material specifications, less advanced design, construction, past damage prevention practices, and latent damage (such as coating damage) from third-party construction activities near the mains.

Figure 5.2-18 shows about 70% of recorded steel main failures in the past 11 years are from pipe installed before 1970.

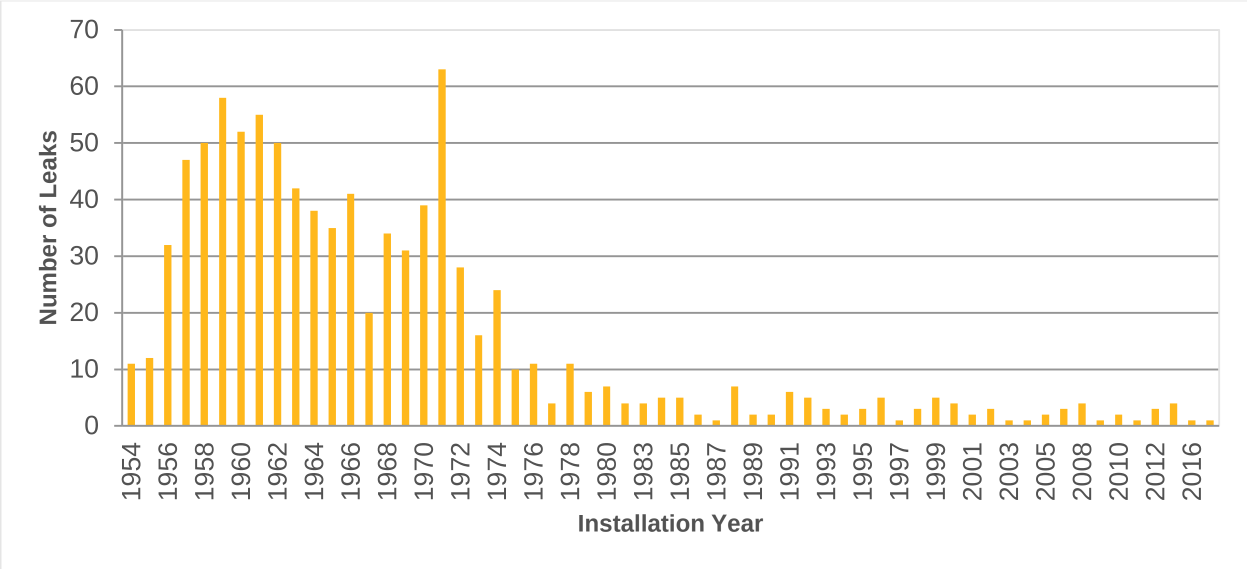


Figure 5.2-18: Number of Steel Main Leaks on Pipe Installed from 1954 to 2016

Using the leak projection model, the Asset Health Review evaluates the probability of failure of the steel main population over the next 40 years in 20-year increments. At a macro level and given the size of its population, steel mains as a group are generally performing well at their current age and over the next 10 years. It is important to note, however, that there are individual pipelines identified to be in poor condition, requiring mitigation as illustrated in the previous examples.

Aside from analytics, tacit knowledge and condition assessments have identified condition issues with some of EGD's vital distribution mains. Damages to these mains could result in significant negative impact to public and worker safety and/or significant customer outages. Condition issues have been identified through tacit knowledge and condition assessments on the following vital mains:

- **NPS 30 Don River Crossing**: Refers to an EGD-owned pipe bridge constructed in 1929 that contains a section of NPS 30 pipe. This pipeline is located in densely populated urban areas in Toronto and supplies residential, commercial, and industrial customers and a natural gas fired power plant. Any interruption of gas supply could have severe consequences. Should the NPS 30 XHP river crossing experience a pipeline defect or sustain damage, EGD will have to either temporarily reduce operating pressures or shut down the pipeline. Any pipe defects or failures that could release gas would require a significant emergency response and could have severe consequences and impact. If this occurs in winter, significant customer outages would immediately occur. The maximum customer loss is approximately 92,500 at -23^{0}C (41DD, GTA Peak Design Temperature). At a minimum, supply would have to be terminated to the natural gas fired power plant, which is the equivalent to the demand of 100,000 residential customers. In the case of bridge damage which could lead to pipeline damage, a significant number of customers may lose gas supply, and would require travelling to two sites to make both sites safe and to restore service once the system issue is remediated. Therefore, an outage of this magnitude may take many days or even weeks to restore service, once the pipeline issue has been addressed.

- **NPS 20 Kipling Oshawa Loop (KOL)**:The NPS 20 KOL is a vintage steel main installed in 1954 and has segments located in densely populated areas in the City of Toronto along major traffic arteries, such as the Gardiner Expressway and the Lake Shore Boulevard. Part of the pipeline is the primary feed to downtown Toronto. A portion of the pipeline is attached to the Keating Railway Bridge which crosses the Don River immediately north of Lake Shore Blvd East. The NPS 20 KOL pipeline has been the main feed to the City of Toronto since it was installed and is required not only to maintain the security of supply to the existing customers but to also manage the expected customer growth from proposed developments. Given the location of this high-pressure line, in the event of a gas leak, it could require shutting down a section of the Gardiner Expressway and Lake Shore Boulevard to ensure public safety as well as to facilitate the emergency repair of the pipeline.

- **NPS 12 St. Laurent**: The NPS 12 St Laurent XHP is a single-fed system that consists of vintage steel mains installed in 1958 and is a critical supply to the city of Ottawa and Gatineau, supplying natural gas to more than 165,000 customers. This pipeline feeds 12 district regulating stations and one header station, including a large population of non-interruptible residential, industrial, and commercial customers (including Parliament buildings), and a natural gas fired power plant.

NPS 30 Don River Crossing

As a result of the existing bridge condition and the extent of undermining at the west bridge abutment caused by erosion from past flooding incidents, EGD evaluated options and identified short- and long-term solutions to address the hazard and risk on the bridge structure and the existing NPS 30 XHP pipeline crossing.

A 2012 study identified that the EGD-owned bridge and pipe crossing becomes flooded during storms stronger than a 10-year weather event. The study also identified areas of concern, such as damaged concrete approach slabs on both the east and west side of the bridge, as well as concrete infill walls with significant delamination and corroded reinforcement.

A follow-up 2016 report indicated that the condition of the westerly abutment was inadequate due to undermining (see **Figure 5.2-19**). Undermining is caused by significant erosion of embankment fill over the years, due to flooding. Temporary remediation was completed in 2017 (as seen in **Figure 5.2-20**). With this remediation it is estimated that one 200-year event or several smaller events can still potentially cause further critical embankment erosion, pipe exposure, or bridge deck destabilization. In addition, the NPS 30 bridge crossing has corrosion issues occurring below the bridge deck where the pipeline rises vertically out of the ground into the bridge (at both ends of the bridge).

As a long-term solution, EGD has identified the need to eliminate the existing above-ground Don River bridge crossings in the City of Toronto and replacing it with new NPS 30 XHP pipe under the Don River using trenchless technology. Installing a new pipeline crossing under the river will eliminate the current above-grade crossing, address the bridge and pipe hazard, and mitigate the associated risk. This initiative will facilitate the removal of the proposed abandoned NPS 30 pipe on the bridge and the bridge structure.

Figure 5.2-19: NPS 30 Pipe Bridge Westerly Abutment Undermining

Figure 5.2-20: Temporary Remediation to the Undermined Abutment

NPS 20 Kipling Oshawa Loop (KOL)

ILI/Integrity dig results on approximately 500 meters of pipe (see **Figure 5.2-21** and **Figure 5.2-22**) indicates significant corrosion. The NPS 20 KOL pipeline is known to have all the characteristics of vintage steel mains as discussed in **Section 5.2.5**, including but not limited to compression couplings on mains and services, reduced depth of cover, shallow blow-off valves, drips/siphons, lack of cathodic protection, live stubs, stray current from hydro infrastructure, and possible contaminated soil.

Figure 5.2-21: NPS 20 KOL Pipeline Displaying 70% Wall Loss Identified by ILI in 2016

Figure 5.2-22: NPS 20 KOL Shallow Cover due to Road Grade Changes

The section of NPS 20 pipe crossing the Don River on the Keating Railway Bridge is showing signs of corrosion (**Figure 5.2-23**). In addition, the pipeline has similar vertical clearance to the river surface and is subject to similar increased weather events/risks as the NPS 30 Don River Crossing. Third-party developments, like the widening of the mouth of the Don River at the Keating Railway Bridge and realignment of the Lake Shore Road, will require EGD to coordinate the replacement and relocation of the section of NPS 20 pipe impacted by the proposed work.

Figure 5.2-23: NPS 20 Pipe Crossing Exhibiting Corrosion

Further investigative work is being carried out to collect additional pipe condition data and confirm features and/or concerns identified through tacit knowledge from internal stakeholders. The information collected will be reviewed and analyzed for accuracy and impact on the pipeline, as part of the asset management process and risk assessment review. The results of the assessments will assist in identifying a plan which will include the required scope of work, timing, and costs associated with addressing any of the identified risk concerns with the NPS 20 KOL pipeline. As noted in previous versions of the Asset Management Plan, EGD has identified the potential replacement of the NPS 20 Lakeshore KOL. The additional pipe condition data collected through the proposed investigative digs will assist in confirming the timing of any replacement work.

EGD has proactively engaged the City of Toronto and third-party developers to identify a number of upcoming developments. These activities (such as the naturalization plans for the Don River, the realignment of the Gardiner Expressway and Lakeshore Boulevard, First Gulf's proposed large development and the city's sewer diversion tunnel) could influence future route selections and timing in the event pipe replacement or relocation is required.

NPS 12 St. Laurent XHP

The NPS 12 St. Laurent XHP line is a vintage steel main located in downtown Ottawa and is known to have all the characteristics of vintage steel as discussed in **Section 5.2.5**. Should the NPS 12 St Laurent XHP line experience a pipeline defect or sustain damage, EGD would have to either temporarily reduce operating pressures or shut down the line. Any pipe defects or failures that could release gas would require a significant emergency response and could have severe consequences. Mitigation for a pipe failure event could be to isolate the line to facilitate the required repairs and if this happened in the winter months, significant customer outages would immediately occur. Maximum customer loss is approximately 61,410 at -29^{0}C (47DD, Peak Design Temperature).

The pipeline history indicates inadequate cathodic protection up to the mid- 1970s which has resulted in the corrosion of the pipe, leading to leaks. With the high number of past main and service branches installed on the NPS 12 XHP pipeline, there is a growing concern with the condition of the field-applied coatings at these locations and the pipe underneath it. A 2006 trial project using Ground Penetrating Radar identified potential corrosion defects that were later confirmed through investigative digs on the main. In addition, latent third-party damages have also led to sections of pipe found with gouges, dents, and damaged coatings that have resulted in wall loss and leaks due to corrosion of the pipe.

Other areas of concern include the existence of live main and service stubs, as well as compression coupling fittings that either have been unrestrained or have existing restraints that are no longer effective. In addition, there is an existing NPS 8 main stub with an unrestrained compression coupling fitting on the NPS 12 St. Laurent pipeline that cannot be restrained or removed as accessing it would involve the exposure of the point of thrust.

Further investigative work is being carried out to collect additional pipe condition data and confirm features and/or concerns identified through tacit knowledge from internal stakeholders across the company's business units. **Figure 5.2-24** shows multiple corrosion sites on a segment of the main. **Figure 5.2-25** shows a number of gouges and dents due to latent damages (damages due to third party activities). In the vicinity of the damage, **Figure 5.2-26** shows coating damage.

Figure 5.2-24: Multiple corrosion sites on NPS 12 St. Laurent XHP

Figure 5.2-25: Gouges and dents due to latent damages

Figure 5.2-26: Coating damages

The information collected will be reviewed and analyzed for accuracy and impact on the pipeline, as part of the asset management process and risk assessment review. The results of the assessments will assist in updates to the plan, including the required scope of work, timing and costs associated with addressing any of the identified risk concerns with the NPS 12 St. Laurent XHP pipeline.

5.2.5.3 Risk and Opportunity

Leaks on steel mains in densely populated areas pose a greater risk than in suburban settings, as the ground surface is often paved across the entire width of the street, leaving no openings for escaping natural gas to vent to the atmosphere. With nearby underground infrastructure becoming the path of least resistance, gas can migrate through these channels and into buildings, creating a gaseous and potentially explosive environment for customers and the public. Corrosion leaks through pinholes are the common mode of failure for steel mains. However, for the pressure-elevated KOL network, an additional risk was identified - compression coupling failures associated with excavation activities can result in an immediate and much greater release of gas compared to releases from pinholes due to corrosion. The results could be catastrophic to workers and the public.

Steel main repairs usually require more planning and resources than plastic main repairs. In many instances, specialized skill sets are needed to install isolation fittings on the steel mains and stop the flow of gas to facilitate the repair. This in turn adds to the repair duration, causing longer service disruptions, more gas loss, and higher repair costs.

Other risks that are associated with pipe failures are relight cost, regulatory penalties, GHG emissions, customer outage and reputational impact to EGD.

Safety risk presents the most aggressive risk increase over the next 40 years, followed by customer satisfaction risk. The increasing risk is driven by increasing leaks projected in the next 40 years. The current risk control strategy is not adequate to manage the accelerating risk in the next 40 years, requiring a proactive risk control strategy to effectively manage risks and meet EGD risk targets.

Figure 5.2-27 shows the sub-groups of steel mains that are within intolerable and conditionally tolerable safety risk levels. 45% of the safety risk comes from the KOL system and 18% of the risk is from the 20% - 30% SMYS pipe system. The majority of these pipes are vintage steel mains located in densely populated areas. This outcome aligns with EGD's experience on vintage steel mains, particularly with concerns regarding the KOL system.

The KOL system not only connects the high pressure network between the GTA and the Oshawa area, it also runs through the core of the city along major roadways to supply large institutions and businesses and feed into the Intermediate Pressure (IP) network, delivering gas to commercial and residential customers. Areas of this system have undergone pressure increases over time in order to serve the increase in customer growth.

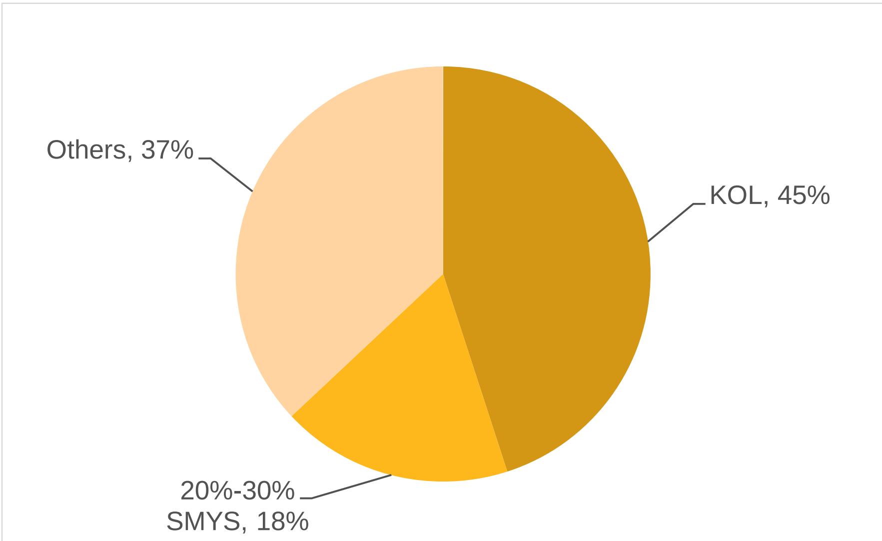


Figure 5.2-27: Safety Risk of Steel Mains in Pipe Length by 2028

5.2.5.4 Strategy

EGD has a Steel Main Replacement Program to address pipeline integrity concerns and compliance issues. These strategies are as follows:

- **Corrosion Prevention Program**: An annual anode replacement program to ensure the steel main system is receiving sufficient cathodic protection.
- **Relocation Program**: A number of relocation projects to address conflict of municipal and third party infrastructures with existing gas facilities, ensuring sufficient depth of cover for the gas pipe and proper clearance to third party utilities.
- **Maximum Operating Pressure (MOP) Program**: Engineering and Records Assessments are required to verify the MOP for targeted pipelines.
- **Emergency Replacement Program**: A program providing emergency response services to leaks and integrity issues discovered on steel mains.
- **Distribution Steel Mains Strategy**
    - **Major Pipelines**: A number of material projects to investigate and manage risks of vital mains that are outside the TIMP program.
    - **Distribution Steel Mains Replacement**: A steel main replacement program forecasted based on leak projections. Condition information and risks are used to identify and prioritize projects.
    - **Continuous Improvement of Analytical Models**: The continual monitoring of steel main performance to refine the analytical models based on best available data.

These strategies will provide the following benefits:

- Address projected increasing leak rates and other integrity issues
- Help EGD manage distribution steel mains assets using life cycle strategies
- Manage the Major Pipelines risk and prevents it from reaching an intolerable risk level
- Continuously improve the analytical models for better prediction of asset condition, support for a longer term replacement plan, and modification the replacement strategy as needed.

Details of each program/strategy are provided below.

Corrosion Prevention Program

The Corrosion Prevention Program consists of annual anode replacements to ensure the steel main system receives sufficient cathodic protection. The program utilizes pipe-to-soil survey results to determine which steel main networks require additional or replacement anodes to improve levels of cathodic protection. In addition to active steel mains, the Corrosion Prevention Program also covers corrosion control on steel casings and replacement of rectifier systems.

Relocation Program

A relocation project is required when a municipality, road authority, outside agency, other utility or other third party constructs or reconstructs a road, bridge, railway, canal, building, etc., and the work is deemed in conflict with an existing gas plant.

The Relocation Program aims to relocate gas carrying assets in conflict with third-party proposed work. The Planning department within EGD ensures such conflicts are avoided. If not, the group ensures conflicts are resolved within the framework of the various third-party agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. Relocation renews the asset by replacing it with new pipe.

Emergency Replacement Program

Refer to **Section 5.2.4.4**.

Distribution Steel Mains Strategy

Major Pipelines

The Major Pipelines Strategy further investigates and remediates a subset of vital mains (HP/XHP) identified through SMA knowledge and special direct assessments requiring additional investigation and/or remediation. These pipelines require a large capital investment and are subject to the OEB's Leave-to Construct (LTC) process.

This subset of pipelines were installed in the mid-1950s, operate at HP or XHP, are located in densely populated urban areas, and supply natural gas to a number of large volume customers where gas service could be impacted and/or public safety put at risk during a pipeline failure. Major pipelines are higher-risk pipe assets critical to the gas distribution system – these pipelines are targeted for replacement within the next 10 years before they reach EGD's identified intolerable risk region. The major pipelines initiatives are as follows:

- **NPS 30 Don River Replacement**: Replacement of the NPS 30 Don River Bridge crossing (Toronto).
- **NPS 20 KOL Investigation**: Condition assessment of the NPS 20 KOL pipeline, analysis of solution options, and monitoring of third-party development activities.
- **NPS 12 St. Laurent Investigation**: Investigation to assess the condition of NPS 12 and NPS 16 XHP mains on St. Laurent Boulevard (Ottawa).

Distribution Steel Mains Replacement

A program targeting higher-risk pipes is required for the long term to manage the increasing safety risk expected in the next 40 years. In light of accelerating leak growth rate projections, it is inefficient to perform large numbers of steel main repairs on an emergency basis (rather than planned proactive replacements) since emergency repairs only improve the condition of very small sections of the affected mains, leaving the overall system still in generally poor condition. Planned replacements eliminate all other active corrosion sites that have not failed yet and avoid the need for multiple leak repairs along the same steel system. It also provides opportunities to be more cost effective.

The risks of interrupting supply to customers and GHG emissions associated with an uncontrolled gas release will increase in the next 40 years. Although the current reactive effort could be sufficient to maintain customer satisfaction at today's leak rate over the next five to10 years, addressing leaks through the reactive program alone would not effectively reduce risk to meet EGD's risk targets in the long run. To ensure a continuous and satisfactory customer experience, a proactive program needs to be in place to actively manage known risks.

To ensure the safe and reliable delivery of natural gas, EGD continues to focus on addressing existing pipeline integrity concerns and compliance issues as they are identified. The 10-year leak rate projections shown in **Figure 5.2-12** illustrate an increase in leaks, requiring an increase in replacement activities. This strategy will facilitate the replacement of steel mains that have experienced failure and integrity issues. Some examples of condition issues that will be addressed are:

- **Vintage Steel Mains:** Refers to steel mains installed in 1970s or earlier. Common issues found on vintage steel mains include unrestrained compression couplings and vertical pipe features such as shallow blow-off valve assemblies and steel drips, which poses a hazard during third party execution activities. The standard pipe coating used in the 1970s gets brittle over time and is susceptible to cracking and disbondment, allowing for corrosion to occur.
- **Isolated Steel Headers**: Refers to steel gas mains on private property (such as shopping malls and condominiums) that supply more than one service. The common installation configuration is to connect a header station to a gas main to reduce gas pressure and supply gas to the header network. Steel headers are isolated from the cathodic protection of the upstream steel gas main network, making it more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.
- **Bridge Crossings**: Refers to mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on the main, casing, and pipe hangers. Annual bridge crossing surveys are conducted to identify faults and issues. Issues found trigger Engineering Assessments, which recommend risk mitigation measures, such as the replacement of components (such as pipe hangers) or the entire bridge crossing, if necessary.
- **Exposed mains or insufficient depth of cover**: Refers to steel mains found to have insufficient depth of cover. Municipal roadwork and city development can alter the road grade and cause gas mains to be shallower than the original installed depth. To the extent possible, depth of cover issues will be addressed by localized mitigation. If localized mitigation is not feasible, it will be mitigated by main replacement.

- **Leaking steel mains or other emergency replacement**: Throughout the year, there are unforeseen short main replacement projects that must be expedited on short notice, such as replacing of a short section of main or fittings that are leaking, removing blow-off assemblies, or repairing mechanical fittings that require immediate attention.

Continuous Improvement of Analytical Models

This strategy over the next 10 years is paced based on projected leak rates. As shown in the corrosion leak projection (**Figure 5.2-13**), at the current replacement rate, the risk will continue to increase. As described in the Asset Health Review, the steel main leak projection model points to an average time to first failure to be approximately 100 years. It is expected that in the next 40 years, the long-term challenge for EGD will be to manage leak acceleration in the steel main system. This is due to the majority of the population approaching 100 years in age. Based on the current inventory (**Table 5.2-3**), more than 2,000 kilometers of pipe will be at or above 100 years in age by the year 2050.

At the current rate of replacement (approximately nine kilometers per year) it would take over 200 years to address 2,200 kilometers of 1950s pipe alone. The potential volume of leaks associated with the increasing amount of pipe over 100 years in age could eventually compromise EGD's ability to maintain a safe and reliable distribution system; depending on the timing and annual rate of replacement, EGD's ability to respond to leaks will be impacted. EGD will continue to refine its Distribution Steel Mains Replacement Strategy to manage this aging asset population based on advancements in the understanding of leak projections, asset age limit, and resource capacity. Considerations will include:

- Monitoring leak rates and improving data collection to further validate and improve the steel main leak projection and risk models
- Continuing to collect condition information on ILI-targeted steel mains outside of the TIMP and operating between 20-30% SMYS
- Evaluating potential logistics and resource constraints based on current leak projections.

5.2.6 Distribution Plastic Mains

Plastic mains were first introduced into EGD's distribution network in 1968 on a field trial basis. Plastic mains became an approved material in 1972 and have since been widely-installed across the EGD franchise area, replacing steel mains in the Low Pressure (LP) and Intermediate Pressure (IP) class systems by the mid-1970s. Plastic mains assets are divided into three different groups: pre-1977, 1977-1985, and post-1985 to denote the different plastic materials (resins) used during the manufacturing process.

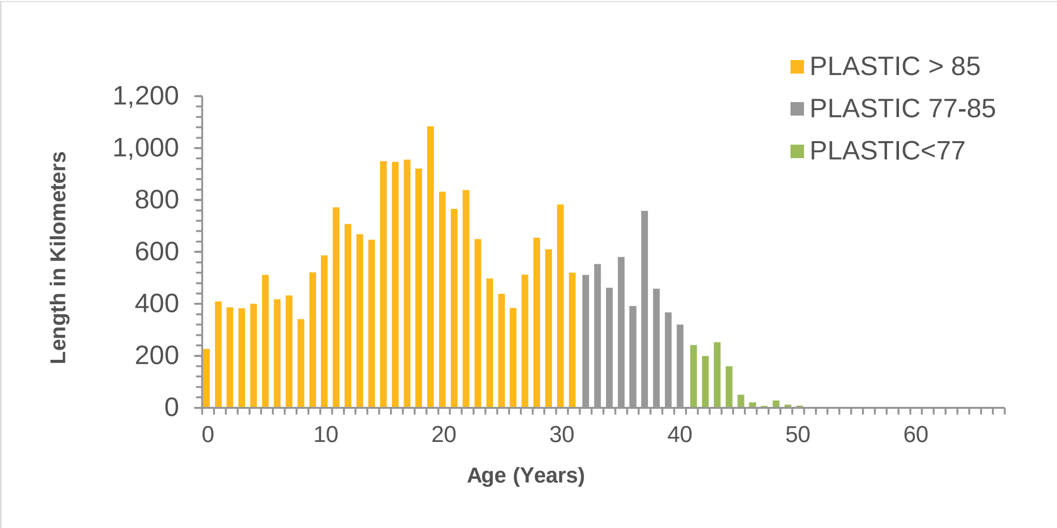


Figure 5.2-28: Current Age Distribution of Plastic Mains

Plastic Mains (Pre-1977)

Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A. The installation period of Aldyl A plastics started in the late 1960s on a field trial basis and was concluded by the end of 1976 when EGD transitioned to a different resin type for plastic mains. The age of the Aldyl A plastic mains currently ranges from 41 to 49 years.

It is well known and studied in the North American gas industry that Aldyl A plastic mains have brittle-like cracking properties. The oxidation of the inner wall surface during manufacturing (also known as Low Ductile Inner Wall (LDIW)) and the large spherulites found in its microstructure causes pipe to be susceptible to premature failure in the form of cracking. Cracking in the Aldyl A pipe wall is further accelerated by additional stress intensifiers such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types, which significantly shorten the expected asset life of Aldyl A plastic mains.

Current studies conducted by North American gas utilities and regulators are specific to Aldyl A mains manufactured by US manufacturing plants. The Aldyl A plastic mains used in EGD were produced by a Canadian manufacturer in Huntsville, Ontario. EGD commissioned a study through the Gas Technology Institute (GTI) to evaluate the performance of varying vintages of Aldyl A pipe used by EGD to identify failure modes over time and to determine the mean time for failure. Results of the initial sample testing showed that the LDIW property was also observed on Canadian-manufactured Aldyl A plastic pipe. The Rate Process Method analysis performed on these initial samples showed that the expected asset life of Aldyl A plastic mains are highly affected by ambient temperature and total stress intensifiers on the pipe.

Plastic Mains (1977 to 1985)

By the end of 1976, EGD stopped using Aldyl A plastic mains and transitioned to installing other resin-based plastic pipes. The installation period of this specific type of plastic main took place from 1977 to 1985. The current asset age of this group of plastic mains ranges from 32 to 40 years.

Plastic Mains (Post-1985)

By the mid-1980s, EGD had started to use a different resin type. The newer generation of plastic resin and the improvement of installation practices resulted in a plastic mains asset that outperformed the earlier assets of its kind. The newer group of plastic experienced fewer failures. EGD continues to gather data to better understand failure modes and mean time to failure.

5.2.6.1 Condition Methodology

Similar to steel mains, the condition of plastic mains are assessed at a macro level using a leak projection model created by applying a structured methodology to convert historical failure data into a statistical model that forecasts the probability of failure (PoF). The leak projections are refined with input obtained through direct assessment, internal and external industry studies, and SMA input.

At EGD, most failures on plastic mains are repaired with an isolated small segment replacement, leaving the remaining plastic mains in their existing condition. Therefore, from a linear asset standpoint, plastic mains are considered a repairable system. The failure data set was analyzed using widely-accepted and applied statistical principles that correlate the age of the asset versus failures. A model is then produced to project the asset's future failure. Through this analysis, failure data was tested against different plastic main attributes, including asset age, region, pressure class, and pipe wall thickness to identify parameters that could impact plastic main failure probability.

In addition to statistical modeling, EGD has also concluded an extensive study on pre-1977 Aldyl A plastic pipe with GTI to develop data-driven predictions on the remaining useful life expectancy of the Aldyl A plastic pipe used in the EGD system.

5.2.6.2 Condition Findings

The resulting leak projection model from the analysis is a Mean Cumulative Function (MCF) that has a very strong correlation to asset age. The leak projection model for pre-1977 plastic mains (as seen in **Figure 5.2-32**) shows a sharp increase in failure rate by age 70. Although the 1977-1985 plastic mains are made of resins different from Aldyl A, the failure data from this group of plastic mains yields a model that closely resembles the trend of the pre-1977 plastic mains. Currently, the behavior and characteristic of the 1977-1985 plastic resins have not been widely studied in the industry. More investigation into the failure data and research on this specific plastic pipe group is required to fully understand this modeling result. The post-1985 plastic mains currently have a much lower leak projection in the foreseeable future, possibly due to the higher quality of manufacturing standards for the plastic resin used during this vintage.

Leak projections for the three different groups of plastic mains, based on historic failure rates are depicted in **Figure 5.2-29**, **Figure 5.2-30**, **Figure 5.2-31**, and **Figure 5.2-32**.

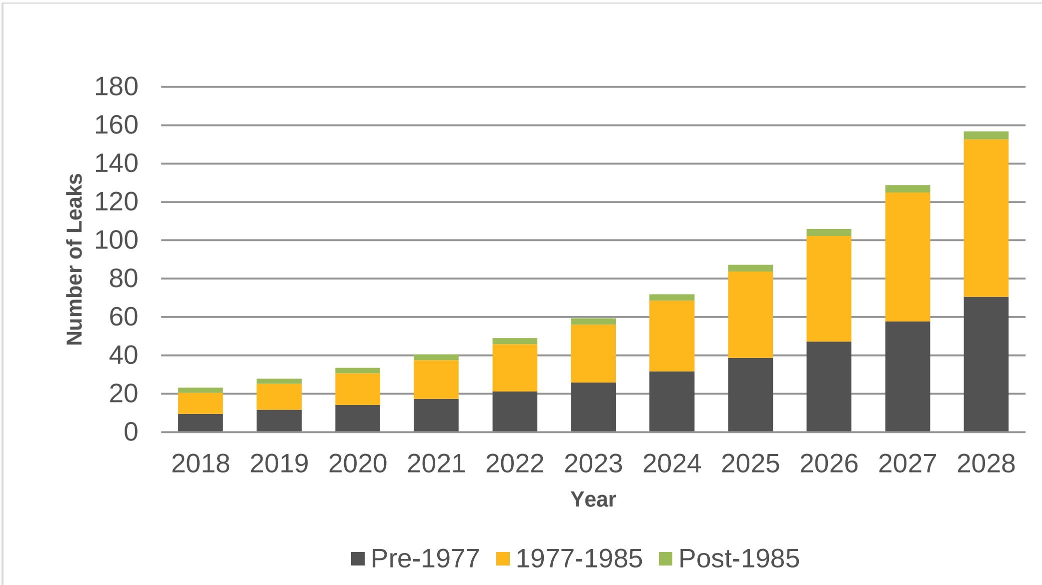


Figure 5.2-29: 10-Year Projection - Total Plastic Mains Annual Leak Rate (2018-2028)

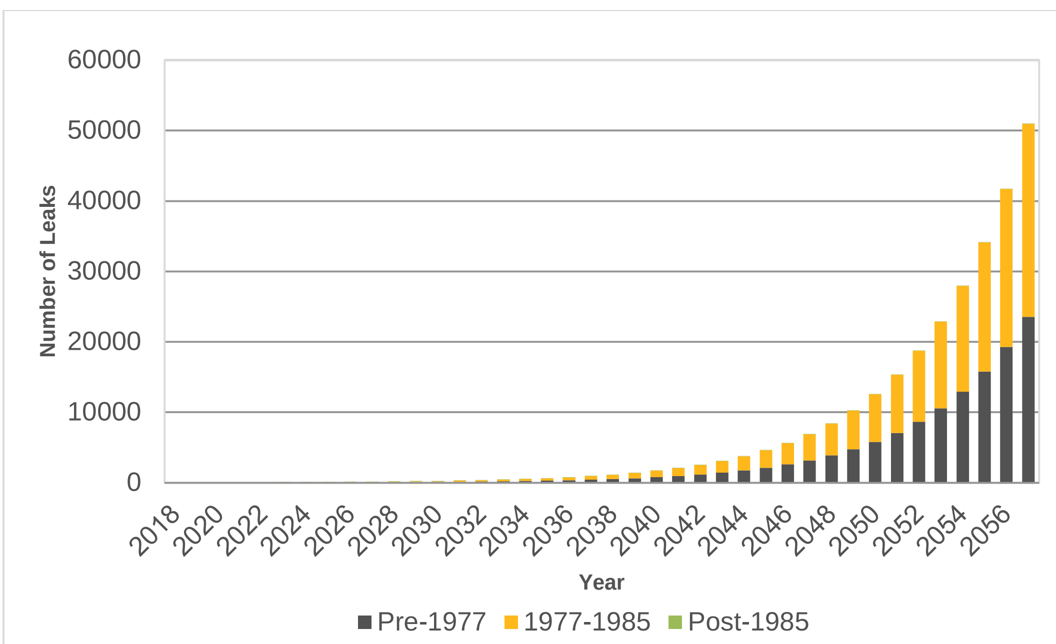


Figure 5.2-30: 40-Year Projection - Total PE Mains Annual Leak Rate (2018-2057)

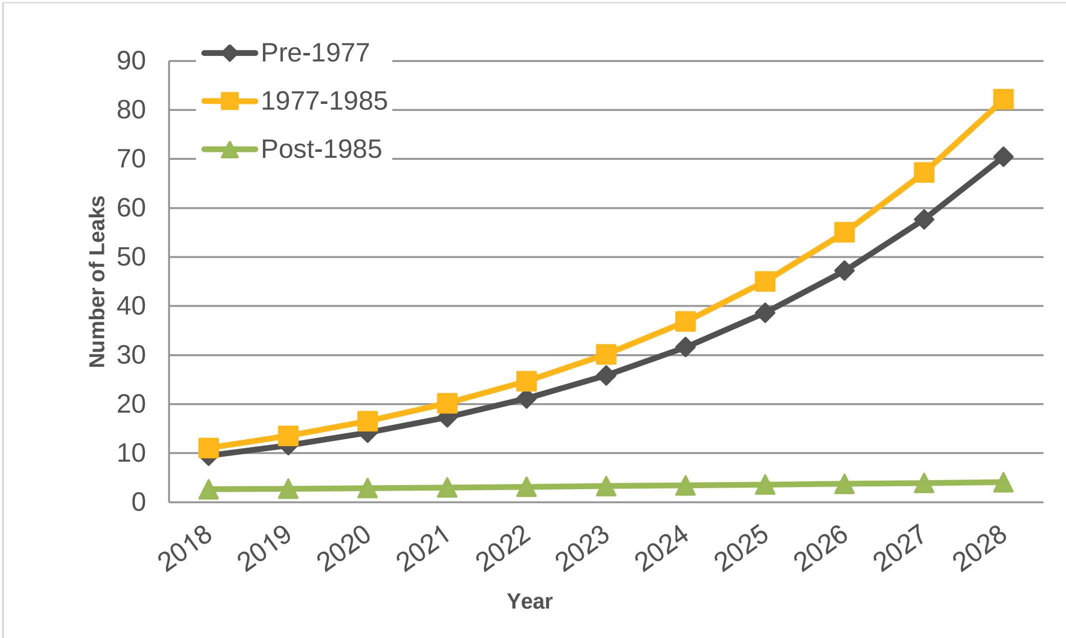


Figure 5.2-31: 10-Year Projection –Plastic Mains Annual Leak Rate by Age Group (2018-2028)

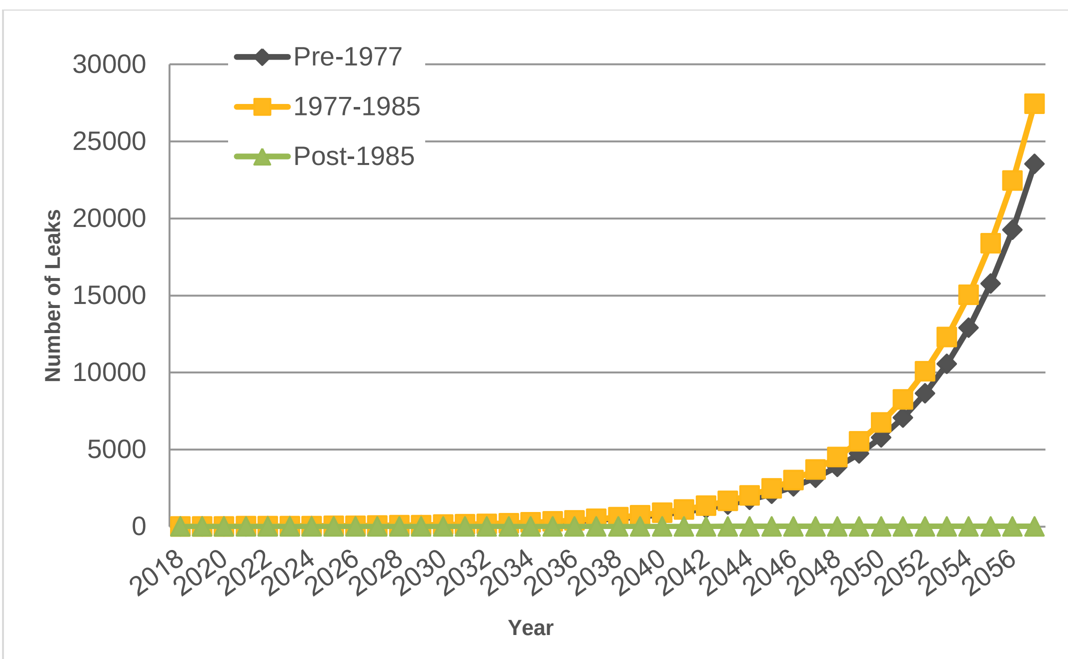


Figure 5.2-32: 40-Year Projection – Plastic Mains Annual Leak Rate by Age Group (2018-2057)

According to the EGD-commissioned GTI study and other research done in the industry, factors such as rock impingement, number of connections, and squeeze-offs can lead to stress intensification. The GTI study of the physical and environmental factors affecting asset life has improved EGD's understanding of the failure behaviour of pre-1977 plastic mains, however, at this time, these factors have not been considered in this model and will be included in future data analytics development.

The asset life of plastic mains was analyzed using several statistical models. This analysis indicates that the asset life for pre-1977 Aldyl A plastic mains is in the 70-year range.

Plastic Mains (pre-1977)

The current population of pre-1977 plastic mains is in generally good condition, however, it is important to note that the entire population is aging and will degrade quickly (see **Figure 5.2-33**). Over the next 30 years, the failure rate accelerates as pre-1977 plastic mains approach 70 years old. The sudden change in performance can be attributed to the LDIW property and slow crack growth (SCG) behavior, as the mains operate with additional stress intensifiers over a long period of time. This combination of material property and operating environment results in the brittle-like cracking of Aldyl A plastic mains (i.e., rapid crack propagation), a finding supported by the GTI study on Aldyl A samples supplied by EGD. The study indicated that by combining different stress factors, the asset life for pre-1977 Aldyl A plastic mains is in the 70-year range. This implies that the residual asset life of the pre-1977 plastic mains could be as short as 10 to 20 years.

Figure 5.2-33: Rapid Crack Propagation on Aldyl A Pipe from Saddle Tee Fusion (Mississauga, ON)

Plastic Mains (1977 to 1985)

From statistical analysis on failure data, it is predicted that 1977-to-1985 and pre-1977 plastic mains will have very similar leak projection trends, leading to the conclusion that the asset health of 1977 to 1985 plastic mains will resemble the general trend of pre-1977 plastic mains, but with a delay in degradation due to the later installation date.

Much like the pre-1977 plastic mains, the 1977 to 1985 group is currently in good condition and will continue to perform over the next 20 years. The population will then start to degrade and because of its size, will result in higher leak rates.

In addition to leak projection, the Material Fault Reporting Program identified multiple cases of 1977-1985 plastic main failure exhibiting similar failure modes (cracking due to extended stress exposure) as the pre-1977 Aldyl A plastic mains. Currently, there is no known industry research or investigation completed on 1977-1985 plastic mains to provide insight to its degradation and failure mechanisms.

Plastic Mains (post-1985)

Post-1985 plastic mains were manufactured with improved resins and installed with advanced construction standards. The industry has proven that these resins do not exhibit SCG issues. These are relatively young assets and have experienced few material failures, and as such statistical analysis to project future failures has been difficult. The entire population of the post-1985 plastic main group is expected to remain in good condition for at least the next 40 years.

5.2.6.3 Risk and Opportunity

SCG issues in pre-1977 plastic mains renders as a steep failure curve, illustrating that the asset performs effectively over time until sudden cracking occurs, drastically accelerating the failure rate in a short period of time. This presents an opportunity to reduce failures by implementing a replacement strategy to manage asset aggregate risk.

The brittle-like cracking observed on plastic mains creates a large opening on the pipe and releases a high volume of uncontrolled gas underground. Without a way to vent to the atmosphere, escaping gas travels through any nearby underground infrastructure, and can potentially migrate into buildings and create a potentially explosive environment. At a high volume flow rate, it would take a much shorter time for gas to accumulate to the explosive limit before it can be detected and reported to the gas company for emergency response.

The current understanding of the 1977 to 1985 and post-1985 plastic mains is that they do not follow the same failure mechanism as pre-1977 Aldyl A plastic mains - failures should not result in pipe cracks.

In order to have a more comprehensive understanding on risks associated with plastic mains, a risk profile will be conducted in the near future to determine how the likelihood of plastic main failure and population/building densities could drive the priority of work for the plastic replacement program.

5.2.6.4 Strategy

EGD evaluates potential asset strategies using safety, financial, and customer satisfaction criteria.

The combined effect of failure mechanisms and the exponential growth of forecasted leaks associated with the pre-1977 plastic mains over the next 20 years are going to increase, and that may challenge the existing resource capacity to respond on an emergency basis, potentially impacting the safe and reliable delivery of natural gas.

The large number of leaks forecasted for plastic mains over the next 20 years will lead to more frequent emergency response and unplanned localized repairs and replacements. These localized repair and replacements indicate that the overall system condition continues to degrade. Planned replacements eliminate potential SCG sites proactively, avoiding the need for multiple leak repairs to the same plastic system.

With more plastic mains failures and emergency repairs forecasted, the number of customer interruptions and GHG emissions associated with an uncontrolled gas release is expected to increase significantly.

For pre-1977 Aldyl A plastic mains, there is sufficient industry data and EGD internal failure history to support the need for a replacement program. As previously stated, the 1977 to 1985 plastic mains will need to be further studied and understood through similar sampling and testing to justify any systematic asset renewal program. EGD continues to monitors all plastic mains through the Leak Survey Program on regular survey cycles; leaks and other material faults with this group of plastic mains will be addressed on a reactive basis.

Plastic Mains (pre-1977) Replacement Program

As previously discussed in **Section 5.2.6.2**, the asset life of pre-1977 Aldyl A mains is estimated to be approximately 70 years. To maintain this average asset age, approximately 900 kilometers of vintage plastic mains must be replaced in the next 25 to 30 years, an average replacement rate of 40 kilometers per year.

To identify an optimal replacement pace, an analysis was performed to identify the residual leak rate associated with different replacement rates over a 40 year period as shown in **Figure 5.2-34**.

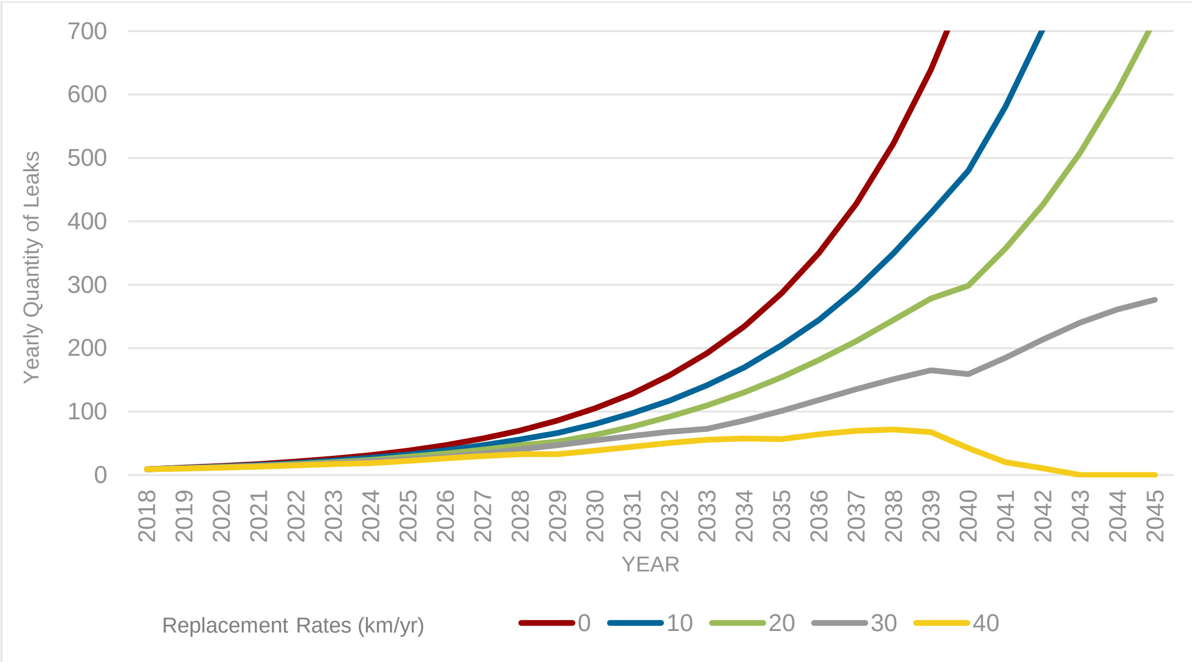


Figure 5.2-34: Annual Plastic Mains Leak Projections (Pre-1977)

Figure 5.2-34 shows the current reactive replacement approach (i.e., no proactive replacement) is no longer a feasible option as the total number of plastic main leaks will increase in the next 20 years. This incremental leak rate may challenge the following:

- EGD's ability to manage the safe and reliable delivery of natural gas
- The effective management of EGD's emergency response and associated operating costs
- EGD's commitment to environmental stewardship in reducing GHG emissions

Pre-1977 Aldyl A plastic mains present a low risk in the short term. However, industry incidents and the GTI study have shown that once Aldyl A plastic mains reach a certain age under specific conditions, they will experience rapid deterioration and failure, exhibiting cracks with greater loss of containment, less control, and greater consequence.

Because of rapid deterioration and high consequence, the strategy is to increase the replacement rate to 20 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced SCG failures due to known stress intensifiers (such as rocky soil type), and replacing early vintage field trial plastic mains pre-dating the official implementation of plastic mains in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life. This strategy ensures the risk is managed over the long term and replacement programs can be adequately resourced. In the short term, failing assets will be repaired or replaced as required. EGD continues to monitor asset conditions to determine if a change in pace is needed.

Plastic Mains (1977 to 1985) Integrity Assessment

An Integrity Assessment sampling and testing 1977-1985 plastic mains will be initiated in 2019 to understand its degradation and failure modes, similar to the Aldyl A plastic main study completed by GTI. Results of the study will be used to develop a model estimating the residual life of this group of plastic mains, which will inform EGD's strategy for this asset. This strategy has the following benefits:

- It provides project planning lead time through a paced ramp-up.
- It manages the long-term risk associated with aging assets.
- It helps EGD manage operating and maintenance costs effectively.
- It provides a better understanding of 1977-1985 plastic main material characteristics and failure mechanisms, which can be used to improve leak projection accuracy.

EGD continually monitors the performance of these assets and refines its analytical models based on best available data. As the quality of models and data continue to improve through the Plan-Do-Check-Act methodology, EGD will be better able to predict asset condition and manage its long term replacement strategy accordingly.

Emergency Replacement Program

Refer to **Section 5.2.4.4.**

Relocation Program

Refer to **Section 5.2.5.4**.

5.2.7 Distribution Services

A distribution service refers to the pipe between the distribution main and the customer's meter set. Over the years, different materials have been used for this asset, including steel, copper, and varying resins of plastic, each with unique characteristics contributing to their performance over time. Services can be repaired or replaced, depending on asset condition and the nature of the issue exhibited. Generally, replacement is the preferred approach to mitigate unacceptable asset condition.

Figure 5.2-35 shows the age and material type distribution of services across the entire population. Approximately 9% of all services are older than 40 years and approximately 3% are older than 50 years. These figures are pertinent in considering the asset's useful life. **Figure 5.2-36** shows the distribution of services by material type across the population. Approximately 91% of services are plastic of different vintages and 9% are steel.

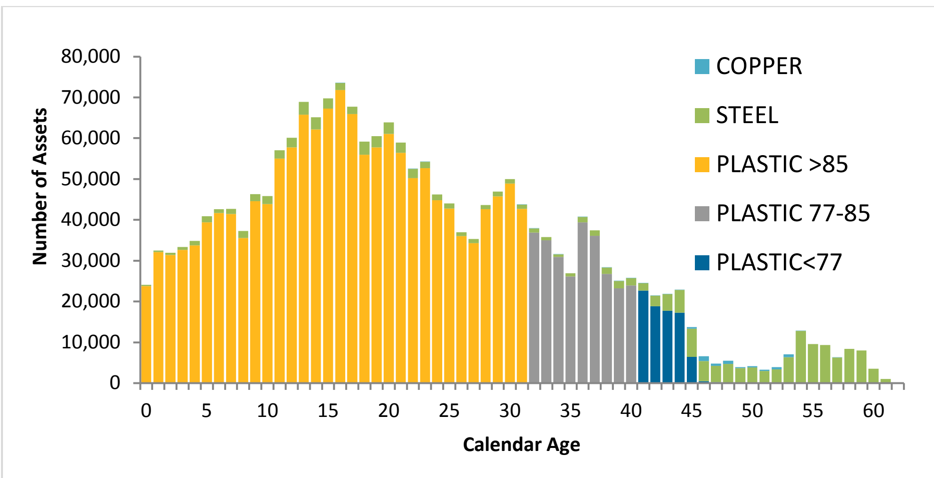


Figure 5.2-35: Service Age Profile by Material Type

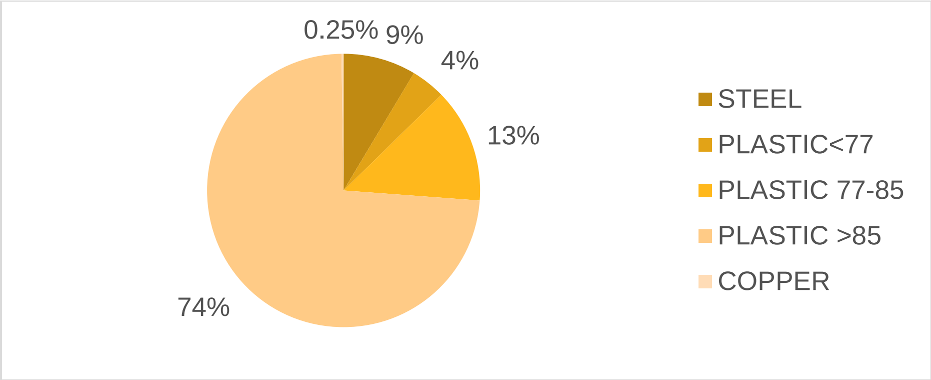


Figure 5.2-36: Distribution of Services by Material Type

5.2.7.1 Condition Methodology

The condition of services is monitored through leak surveys, corrosion surveys, Integrity Assessments, and material fault reporting, as well as opportunistic replacement through vintage mains replacement or relocation programs. Replacement programs allow for an asset to be removed from service through a reactive replacement program due to leaks, compliance non-conformances (lack of cathodic protection, poor coatings, obsolete mechanical fittings, etc.), or as a part of a broader localized mains replacement (which includes replacing all attached services).

Distribution services are susceptible to additional age and condition-related considerations specific to material type. Services are vulnerable to safety risks specific to cross bores. Cross bores occur in trenchless technology when a gas main or service being installed pierces through the sewer line. Over time, the cross bore blocks the sewer line and is usually reported when a customer notices poor drainage from their home's water drainage system. Cross bores can become a public risk when a sewer is blocked, and a customer, their contractor, or the municipality cleans out the sewer line with rotary cutting or water jetting equipment. This equipment is extended through the sewer line and physically clears any obstructions, including the main or service that has penetrated the sewer. This damage can result in natural gas migration through the path of least resistance within the sewer system and into homes and buildings, creating a safety issue.

Steel Services

Steel services are the oldest service type in the distribution system and make up approximately 9% of the total population. Approximately 178,000 steel services and a small number of steel tubings are currently in active use, with 41% (72,000) of these assets installed more than 50 years ago (see **Figure 5.2-37**). At the time of installation, these services are coated and cathodically protected to prevent corrosion. Over time, construction practices, coating types, and materials associated with field-applied coatings (e.g., at the tie-in fitting to the main) create corrosion vulnerabilities. Steel services are exposed to similar installation and environmental stressors as steel mains (see **Section 5.2.5**) and perform comparably. However, steel services do not experience the full extent of the municipal infrastructure encroachment impact (such as damages and stray current) affecting steel mains. The degradation process and failure rates for steel services are associated with corrosion, exacerbated by poor coatings, poor cathodic protection over time, and environmental stressors (such as soil type) that accelerate the degradation process and shorten a service’s useful life.

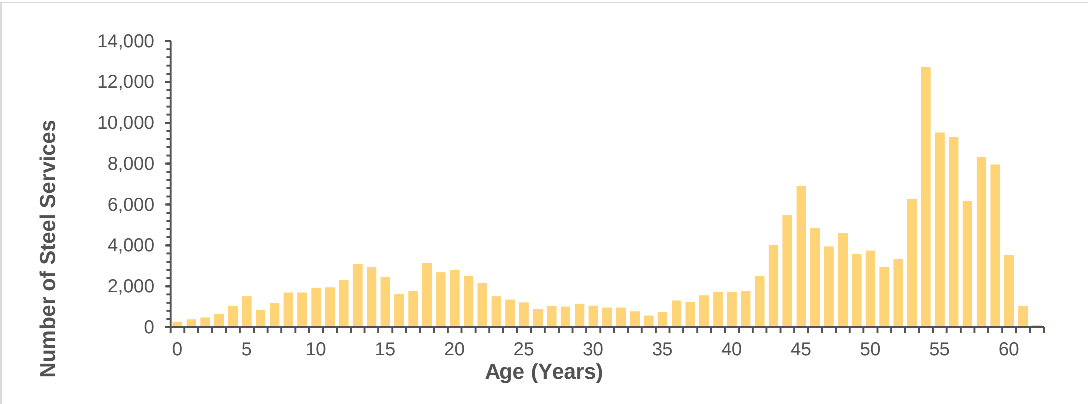


Figure 5.2-37: Current Age Distribution of Steel Services

Isolated steel services are a small population of steel services (numbering approximately 2,200) that are disconnected from the cathodic protection of the original parent steel main. This occurs when poorly performing steel mains are replaced with plastic mains and existing steel services are reconnected to the plastic mains, isolating the services from the cathodic protection received through the original steel main. To remain cathodically protected, these isolated assets are reliant on their coatings and localized anode protection systems. Over time, these localized, sacrificial anodes degrade and no longer protect the service. The lack of cathodic protection over time, coupled with poor coating condition and environmental stressors causes accelerated degradation of isolated steel services and results in accelerated corrosion growth, which can ultimately lead to failure and loss of containment.

Plastic Services

The use of plastic as a service material began in the early 1970s and predominantly replaced steel in the low and intermediate distribution pressure categories. The 1960s to the 1980s was a high-growth period for EGD, as shown by the steady growth of the plastic services population (see **Figure 5.2-38**). The standards associated with fusions of early plastic resins used around this time period were not developed to the same quality as current systems and past installation practices did not ensure the same fusion integrity for pipe and fittings. This resulted in sub-standard pipe fusions being discovered today as asset failures.

Different resins were used over time, with early resins being prone to early failures associated with SCG issues. For this reason, EGD's approach to plastic services assets are categorized using the same vintages as plastic mains - pre-1977, 1977 to1985, and post-1985. Approximately 1,903,000 plastic services are currently in active use, and 4% (84,000) were installed more than 40 years ago.

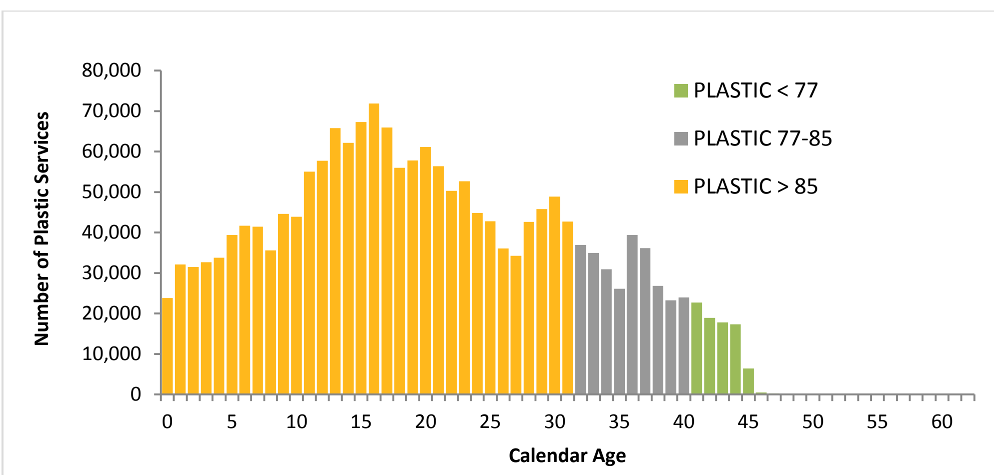


Figure 5.2-38: Plastic Services Age Distribution

Copper Services

Operational problems encountered with copper assets include leaks and choked flow resulting in the interruption of gas service due to copper build-up (a by-product of corrosion). Degradation mechanisms for copper services include galvanic corrosion in the vicinity of the copper service connection to the main, external corrosion at above- and below-ground transitions, and internal corrosion known as erosion corrosion, which causes thinning of the service wall over time. These failure mechanisms manifest themselves through pinhole leaks, circumferential cracks, and choking of the service.

5.2.7.2 Condition Findings

The current condition of distribution services is monitored as described in **Section 5.2.7.1**. Future condition is evaluated with statistical models that take into account the known age-related degradation through material and installation practice considerations. Asset health for services was evaluated using performance history of the asset through failure data over a 10-year period, supported by SMA tacit knowledge. Since services are a replaceable asset, the Weibull model is considered to be the most appropriate statistical model to predict failure rates anticipated over the next 40 years. This model considers 10 years of asset failure data to project future failures. Leak projection models do not include operational conditions and external factors known to affect asset performance over time. As a result, leak projection results were derived using a limited approach.

Steel Services

Figure 5.2-39 shows the projected steel services failure rate increases by approximately 6.5% annually. Steel services are predicted to demonstrate a gradual increasing trend in failures over the next 10 to 15 years. This is consistent with EGD's understanding of the corrosion growth of steel assets, which will degrade over time and will need to be replaced at an increased rate.

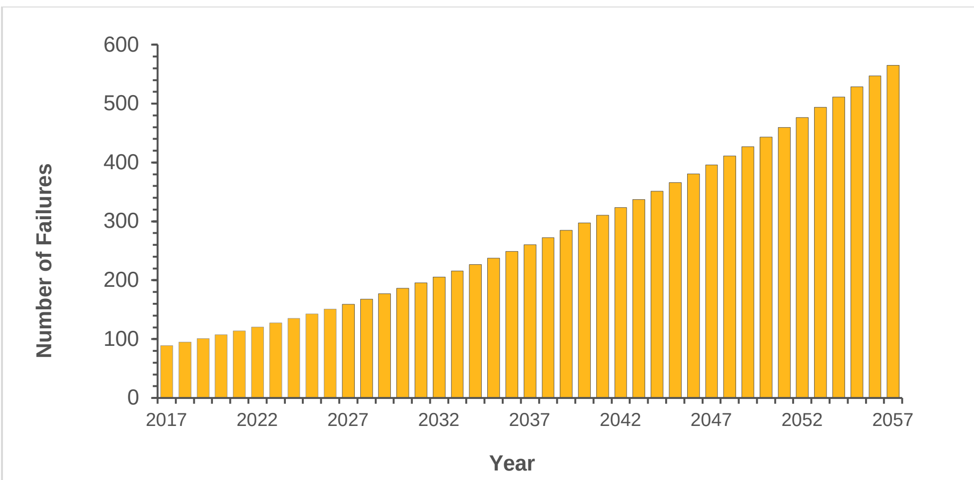


Figure 5.2-39: Leak Projection Rates for Steel Services

In evaluating asset health, EGD is interested in the current baseline health and the degradation rate over time. The degradation rate and subsequent failures inform the actions required to mitigate risk to the lowest practicable level. This provides a view to the predicted timing at which failures in the future will start to overwhelm EGD's ability to manage leak rates and the general safety and reliability of the system. This in turn informs the response required to manage the long term asset condition.

Asset Health Review results indicate the general asset health for the steel services population is stable over the next 40 years. The failure mode of this asset is loss of containment along the service, or at the tie-in connection to the main (generally manifesting as pinholes) that develop over time because of poor coatings or inadequate cathodic protection. Cumulative failures will exceed 11,000 over the next 40 years (**Figure 5.2-40**).

The leak projection models are primarily related to corrosion and exclude other contributing factors such as cathodic protection history, field-applied coating type, number of service connections, and soil type that could reduce the expected service life span. Data used to create the models is limited and its results can be considered a conservative evaluation of the response needed to address steel services. The leak projection models will be improved as more data becomes available.

Plastic Services

Plastic services have been observed to leak due to cracking - failures are projected to increase at an annual rate of 4 to 16% depending on the installation era. Plastic services estimated to fail at higher rates are from pre-1977, as seen in **Figure 5.2-40**. The 10-year failure data used was restricted to time-dependent failures directly associated with the service pipe that did not result from third-party damage. Fittings and service connection failures were also included.

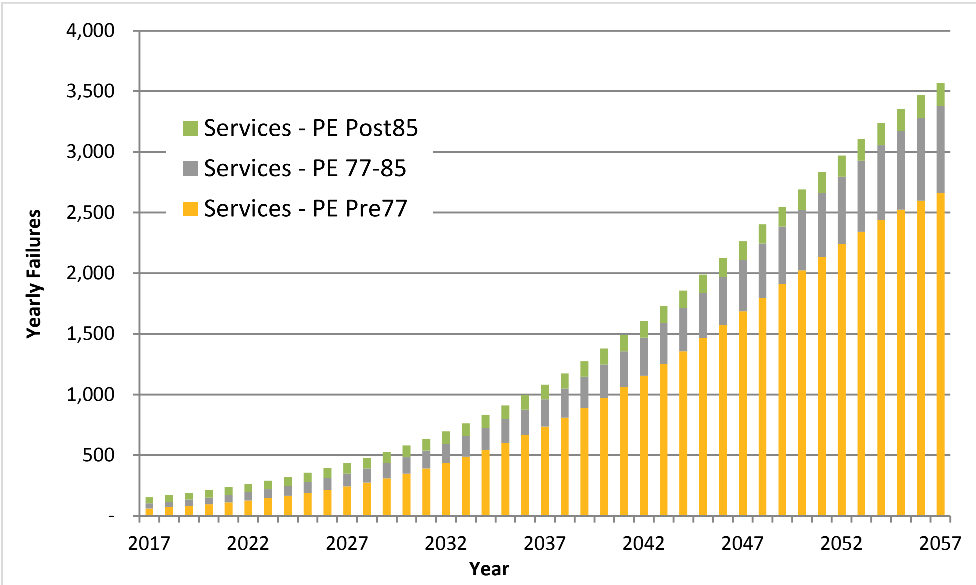


Figure 5.2-40: Plastic Services Annual Failure Rate by Material Type

As non-repairable assets approach end-of-life, they fail at an increasing rate and the accumulation of those failures over time will begin to account for a greater proportion of the total population. It can be seen that the pre-1977 plastic services are projected to have a faster growth in leak rate than the other two groups of plastic services. Because the failure rate of Aldyl A services is currently low, the failure rate projections do not necessarily reflect the failures that may occur in the future associated with LDIW. This failure will be monitored and assessed over time to ensure the rate is not increasing beyond what is currently predicted.

Plastic Services (pre-1977): Pre-1977 plastic services refer to Aldyl A vintage plastic using early manufactured resins. These services range in age from 41 to 50 years, and account for 4% of the total services (approximately 84,000). Failures of these services are generally associated with cracking, installation fusion practices of the era, or threaded cap leaks at the connection of these services to the main (currently unaccounted for in the current leak projection model). Failures associated with plastic services are expected to increase over time. It is important to note that these services are attached to pre-1977 plastic mains, which will begin to experience failures at a rapidly increasing rate as it ages.

A study conducted by GTI found that LDIW exists in Canadian-manufactured pipe. LDIW is detected through the presence of large inner bore spherulites and surface oxidation. Both these conditions independently make certain vintages of Aldyl A vulnerable to accelerated failures due to brittle-like cracking.

Pipe stressors create localized stress intensifications, impacting the probability of Aldyl A service failure. These stress intensifiers are created by activities such as: fusing fittings onto the pipe, creating a reduced bend radius upon installation, squeezing off of the pipe to allow for repairs, and impingement resulting from soil settlement, frost heave, growth of tree roots, and unreported damages.

Though Aldyl A services are not subjected to the same stressors as Aldyl A mains, their failure modes are identical, with consequences more severe than the typical pinhole failure of steel services. Cracking failures have higher consequences, as sudden cracking produces a higher volume of natural gas released compared to pinhole failures due to corrosion observed in steel services. Migration of gas occurs very quickly and response time is of significant importance in mitigating the potential consequences.

The GTI study identified that the remaining life of Aldyl A varies between 10 and 50 years, dependent on the level of stress and other influencing factors. It is expected that when failures do occur, the rapid degradation of Aldyl A services may prove difficult to manage. Further studies are required to identify which stress intensifiers are applicable in the EGD distribution network and how the combined effect of environmental factors affect Aldyl A useful life.

Figure 5.2-40 shows pre-1977 polyethylene services will begin to fail abruptly and at a relatively young age. The majority of the population lies between 41 and 47 years of age - plotted against the projected ratio of failed assets, the projected model shows the rate of failures will increase over the next 10 years. However, this assessment is based on the failure history on the pre-1977 plastic services and does not account for the stressors identified in the GTI study - it provides a conservative outlook of the population health, assuming no stressors exist in the system. The GTI study indicates the failure curve will be very steep for certain populations of this asset when multiple stressors are present.

Plastic Services (1977 to 1985): Plastic services installed after 1977 do not exhibit the same failure mechanisms as pre-1977 vintage plastic services. Typical failures of this asset are leaks at the threaded cap of the punch tee and poorly performed fusions. Failures associated with this group are expected to increase over time. However the general asset health of the overall 1977 to 1985 plastic service population is expected to be stable over the next 40 years.

Figure 5.2-38 shows the majority of the population ranges between 32 and 40 years old. **Figure 5.2-43** shows that the number of failures is low compared to pre-1977 plastic mains, and the failure rate is not expected to increase significantly over the next 20 years.

Plastic Services (post-1985): Post 1985, newer resins were used in manufacturing plastic mains and services. Similar to plastic mains of this vintage, this group of services is in good condition and projected to remain stable for a long period of time based on the leak projection model. The growth degradation figures indicate failures expected to occur over time are manageable without impacting existing levels of natural gas delivery.

Figure 5.2-40 shows that similar to 1977 to 1985 plastic services, failures of post-1985 plastic services are expected to increase over time. However, the general health of this asset population is expected to be stable over the next 40 years. The failure distribution of post-1985 services is dispersed over a long period of time.

Copper Services

Copper services were installed from 1960 to 1979 and annual failure rates are steadily increasing (see **Figure 5.2-41**). Highest-risk copper services have been removed from the system, and remaining copper services now require replacement to prevent future failures. Copper services are not included in the asset health review as they are discrete in number and an existing replacement program is in place.

The proactive Copper Services Replacement Program aims to remove all remaining active copper services before failure, and replace these assets with new plastic services and anodeless risers over the next 10 years. Copper services face external and internal corrosion that may eventually result in leaks or choked services.

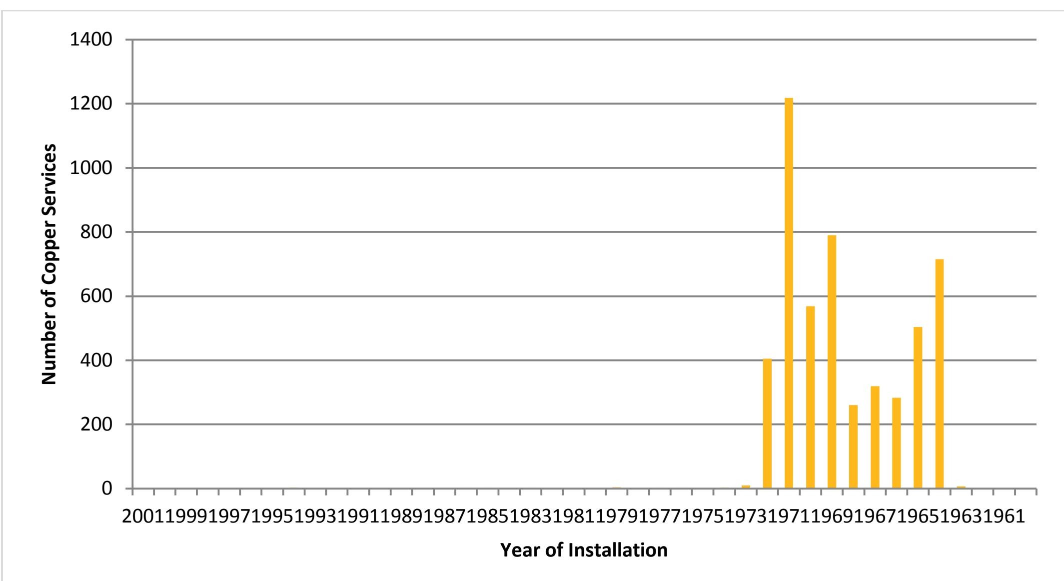


Figure 5.2-41: Copper Services: Population by Installation Year

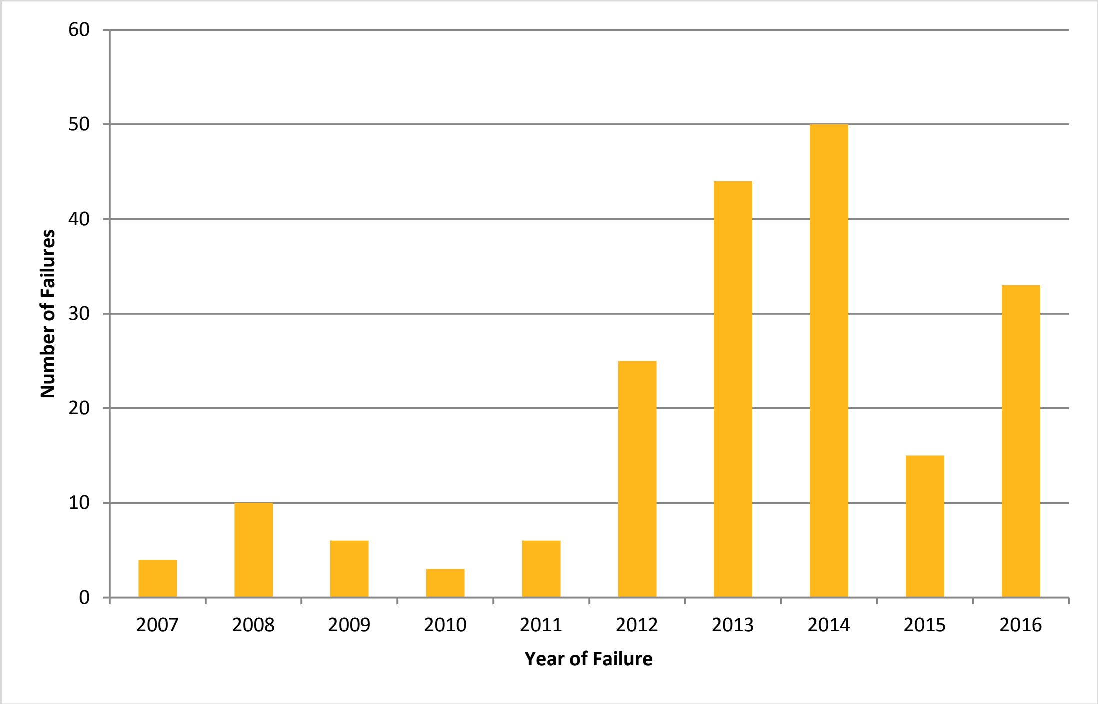


Figure 5.2-42: Copper Services – Number of Failures by Year

Figure 5.2-42 shows an increased failure rate of the installed population - the proactive replacement program for copper services is required to keep safety concerns managed to an acceptable level.

5.2.7.3 Risk and Opportunity

Service lines are the second closest underground gas infrastructure to a building - a service leak usually has a more direct path to the building foundation, increasing the chance of migration. Natural gas migrating into a building has the potential of creating a gaseous and potentially explosive environment, which poses safety and property risks.

The consequences of these failures are dependent on the proximity of the service to building premises, number of linear assets in the vicinity, foundation integrity, and surface structures (soft/hard street surface).

A service's material type is a key factor in these types of failures:

- Failures for steel services (including steel tubings) generally present as pinholes.
- Failures for plastic services present as cracks. Other failures present as punch tee cap leaks.
- Failures for copper services present as external and internal corrosion.

The risks and consequences associated with potential failures on these assets are described in three categories: safety, financial, and customer satisfaction. EGD is exposed to safety risks due to gas leaks which can migrate through underground infrastructure into buildings, resulting in gas accumulation, potentially igniting and resulting in fire or explosion. Financial risks are due to repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by a gas leak. Customer satisfaction risks identified are associated with GHG emissions, environmental impact, service interruptions, and reputational damages.

The consequences of pipeline service failures are quantified and evaluated by translating the condition and leak projection to risk. This evaluation indicates that as the failure rate increases, so does cumulative asset risk.

5.2.7.4 Strategy

The strategy for distribution services is to continue monitoring condition-based and customer-related drivers that trigger the need to replace these assets. Condition-based drivers are monitored through existing activities of the Integrity Management Programs (such as leak and corrosion surveys) to identify leaks in a timely manner and replace services as needed or opportunistically through vintage mains replacement programs or relocation projects. When analysis shows that the failure rate of these assets starts to challenge resource capacity required to address failures, a targeted replacement plan for the services will be developed to ensure risk is mitigated to the lowest practicable level. The customer-based driver for service relays, such as building demolition or service alteration, cannot be accurately predicted and forecasted through a model. Therefore, an estimate was applied using a three-year average to project future volume of customer driven service relays.

Over time, EGD continues to evaluate asset condition and adjust its strategy accordingly to manage the long term integrity of distribution services.

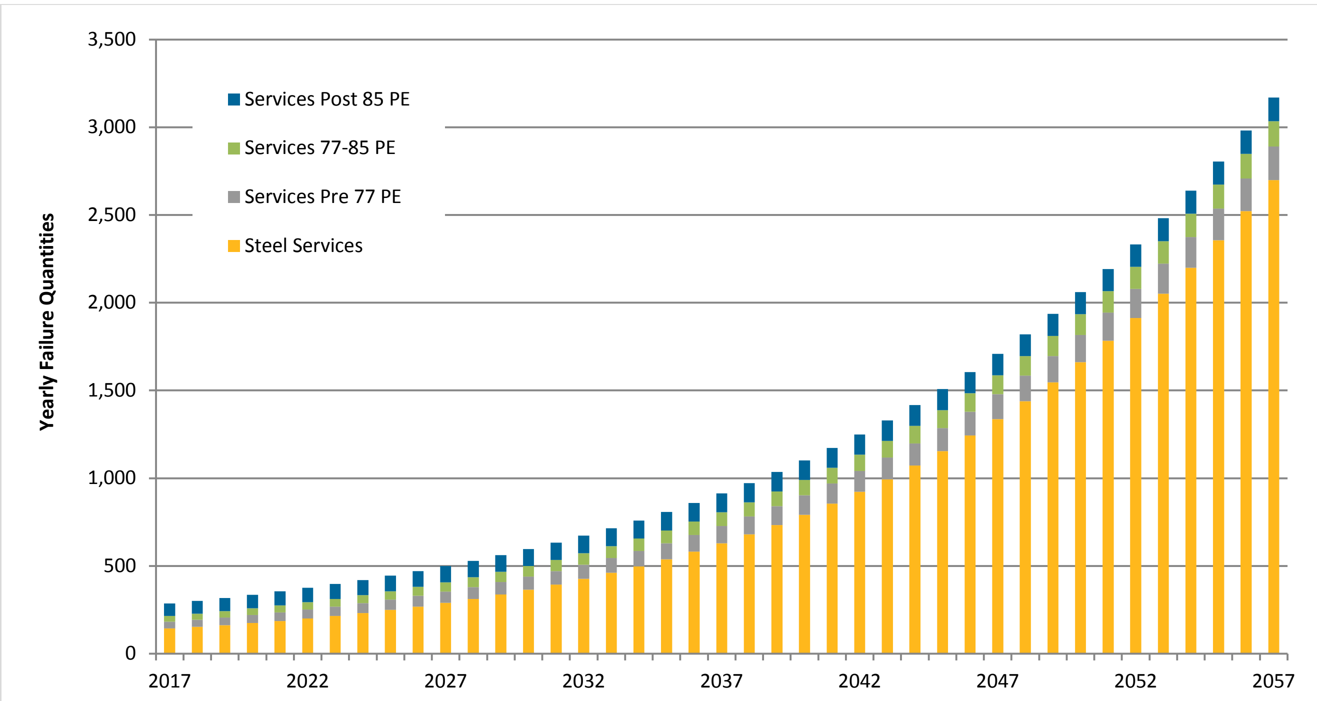


Figure 5.2-43: Leak Projections – Steel and Plastic Services

Service lines continue to be monitored through the Leak Survey and Corrosion Survey programs and replaced when leaks are detected, if damaged by a third party, or as part of a mains replacement or relocation program. In the shorter term, the current annual service replacement program will continue to manage at risk or non-compliant assets. Aging steel services will be replaced as part of the vintage steel mains replacement program. Programs to address isolated steel services and select copper services will also be executed. Other service assets will be replaced on an as-needed basis when they begin to leak. The Plan-Do-Check-Act process will inform on the development of targeted replacement programs if failure rates increase significantly.

Leaking services found through the leak survey process will be replaced immediately or scheduled depending on the leak classification. A targeted replacement program will be designed when it is expected that the leak rate/severity exceeds the ability to manage the safety and reliability associated with these assets.

The most effective strategy to mitigate the risk associated with Aldyl A services is to develop a targeted approach to identifying high risk pipelines, as only very specific pipeline segments are prone to accelerated degradation.

Generally, service relay activities are funded through an annual Service Relay program. These relays are initiated by field operations for safety, integrity, and compliance purposes, such as relaying a leaking or shallow service line. Service relays could also be requested by a third party (contractor, city, authority, customers, etc.) to accommodate building demolition, utility conflicts, and for public safety reasons.

5.2.8 Distribution Risers

Risers refer to the piping that transitions between the below-ground distribution service and the above-ground meter set. Over the years, different materials and fitting configurations have been used, including steel, copper, anodeless, and plastic within conduits, with their unique characteristics contributing to performance over time. The riser type used depended on the material type of the service, delivery pressure, performance of previous generations of risers, and the development of new materials fit for purpose.

Risers can be repaired or replaced depending on the asset condition. Replacement is preferred to mitigate asset failures, as repairs are a short term solution. **Figure 5.2-44** shows the distribution of risers by calendar age. Approximately 10% of all risers are older than 40 years and 4% are older than 50 years. Older risers are made of steel, which corrode and leak as they age. **Figure 5.2-45** shows the distribution of risers by material type. The most vulnerable risers in the system are copper (AMP) risers which make up approximately 14% of the overall population (approximately 285,000 units), and are subjected to an erosion corrosion method of internal degradation, resulting in either pinholes or cracks. This data is used when considering an asset’s useful life, and the length of time it would take to remove these assets from service before they reach end-of-life.

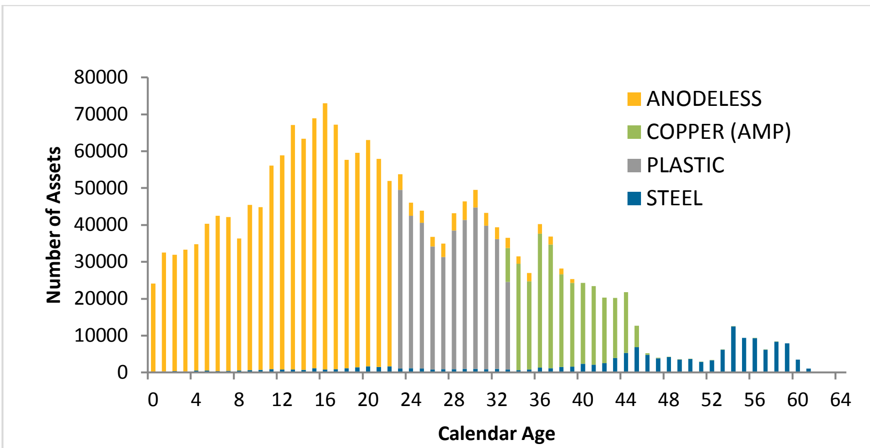


Figure 5.2-44: Riser Age Profile by Material

Figure 5.2-45 shows risers by material type - 59% of are anodeless, 20% plastic, 14% copper, and 7% steel.

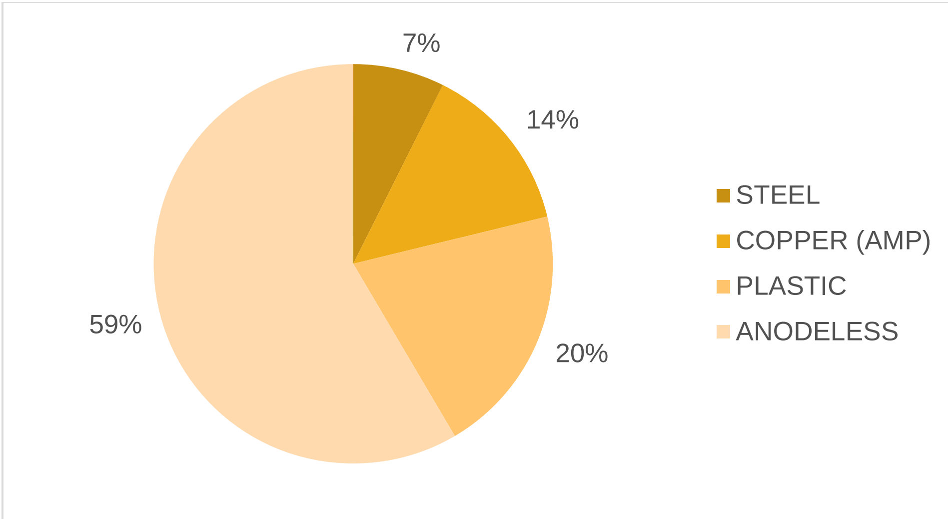


Figure 5.2-45: Distribution of Risers by Material Type

5.2.8.1 Condition Methodology

EGD uses four distinct materials for distribution risers, each of them with unique issues that require specific management throughout their life cycle. The condition of distribution risers is monitored through Integrity Management Programs such as leak and corrosion surveys, as well as opportunistic replacement through vintage mains replacement or relocation programs. Replacement programs allow for an asset to be removed through either a reactive replacement program due to leaks or for compliance reasons (lack of cathodic protection, poor coatings, and obsolete mechanical fittings, etc.) or as a part of a broader localized mains replacement (which includes replacing all attached risers and services).

Asset health for risers was evaluated using the performance history of the asset through failure data over a 10-year period, supported by SMA knowledge. Since distribution risers are a replaceable asset, the Weibull model is considered to be the most appropriate statistical model to predict failure rates anticipated over the next 40 years. This model considers 10 years of asset failure data to project future failures.

Steel risers

Steel risers are the oldest material type in the distribution system and make up approximately 7% of the total riser population. There are approximately 150,000 steel risers in active use and 47% (71,000) are over 50 years old (see **Figure 5.2-46**).

Steel risers are coated and cathodically protected at the time of installation to prevent premature degradation. Over time, evolution of construction practices, coating types, and localized damages create vulnerabilities to corrosion. Steel risers are exposed to similar installation and environmental stressors as steel main assets and therefore perform comparably. However, they do not experience the extent of the municipal infrastructure encroachment impact (such as damages and stray current) affecting steel mains. The degradation process and failure rates for steel risers are associated with below- and above-ground corrosion. Magnifiers of this failure mechanism are associated with poor coatings, poor cathodic protection over time, and environmental stressors such as soil type.

Risers connected to isolated steel services are a small population of steel risers that are isolated from the cathodic protection of the original parent steel main. The concerns related to isolated steel services are discussed in the **Section 5.2.7** and similarly apply to steel risers.

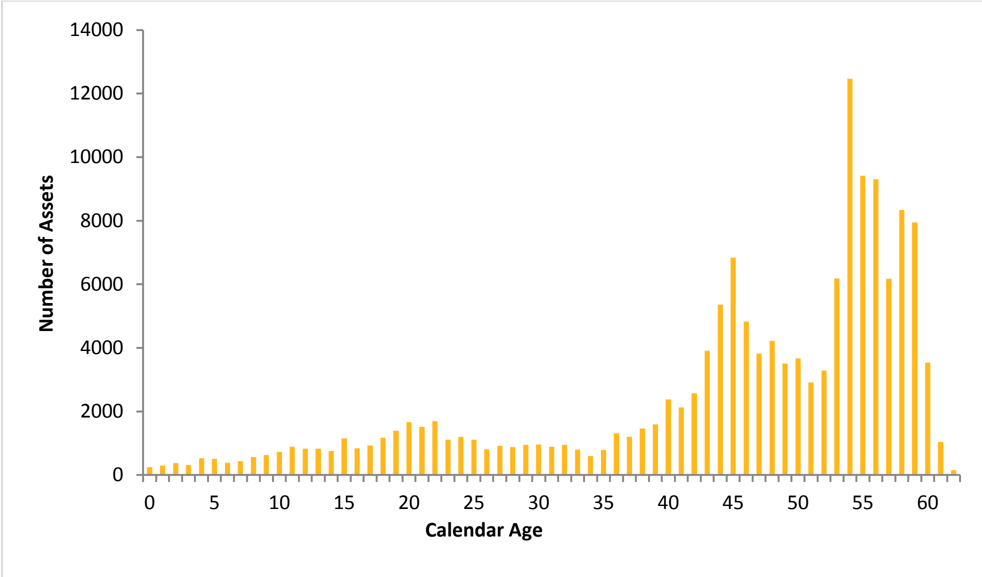


Figure 5.2-46: Steel Riser Age Profile

Plastic-in-Conduit Risers

A plastic riser installed in a conduit protects the plastic from the damaging effects of the environment. Plastic-in-conduit risers account for approximately 20% of the total riser population (see **Figure 5.2-47**). Approximately 413,000 plastic-in-conduit risers are in active use, ranging in age from 23-33 years. Over time, inconsistent construction practices, coating types, and localized damages create vulnerabilities to the corrosion of the conduit. Once the conduit is compromised, the plastic becomes exposed to the environment and to ultraviolet rays, causing degradation to the plastic, eventual failure, and loss of containment.

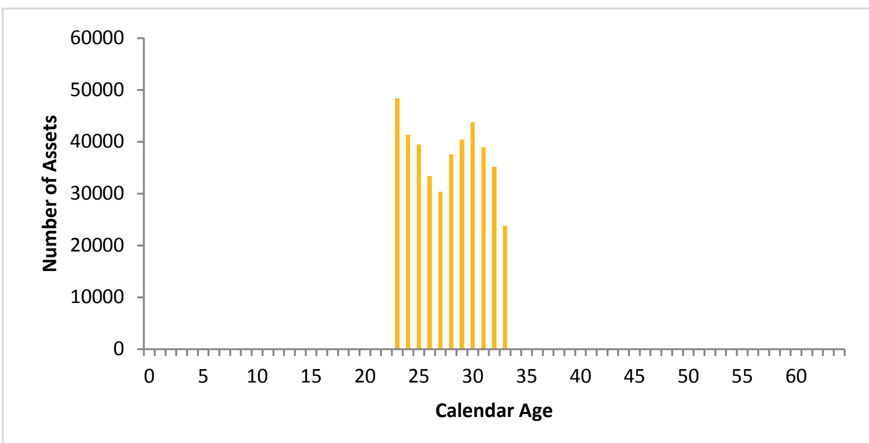


Figure 5.2-47: Plastic Risers Age Profile

Anodeless Risers

Anodeless risers provide a transition between below-ground plastic pipe and steel pipe and do not require cathodic protection. Corrosion prevention is achieved through electrostatic application of an epoxy coating. These risers are the youngest population of risers, with the majority of the population younger than 25 years (see **Figure 5.2-48**).

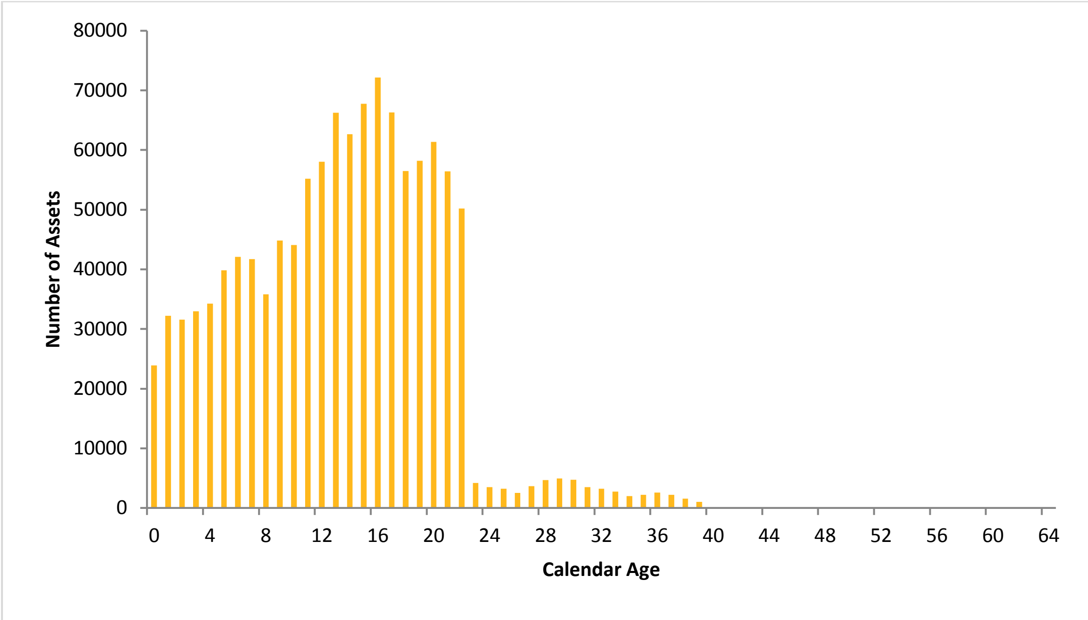


Figure 5.2-48: Anodeless Riser Age Profile

Copper Risers

Copper risers consist of an AMP fitting (a mechanical transition fitting between the plastic service and the copper riser) and were installed between 1969 and 1984. During this period, the unavailability of a plastic transitional riser made the AMP fitting the chosen configuration for new residential services. As of 2018, there are over 284,000 copper risers associated with active services. **Figure 5.2-49** shows the quantity of copper risers in the network and their age as of 2018.

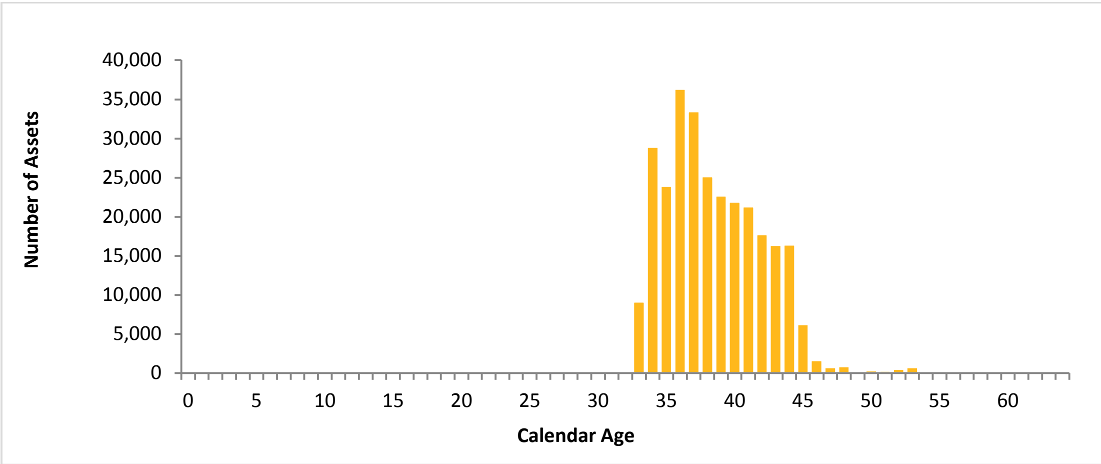


Figure 5.2-49: Age of Copper Risers

Figure 5.2-50 and **Figure 5.2-51** provide a magnified view of an AMP fitting assembly and a typical AMP fitting installation used throughout EGD's franchise area.

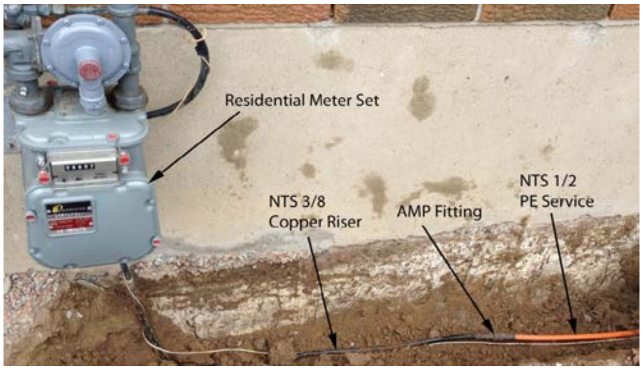


Figure 5.2-50: AMP Fitting Assembly

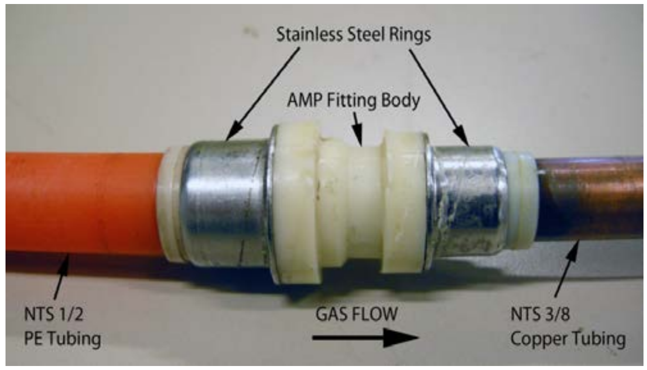


Figure 5.2-51: Typical AMP Fitting Installation

5.2.8.2 Condition Findings

The current condition of distribution risers is monitored as described in **Section 5.2.8.1**. Future condition is evaluated with statistical models that take into account known age-related degradation due to material and installation practice considerations.

In evaluating asset health, EGD is interested in the current baseline health and the degradation rate over time. The degradation rate and subsequent failures inform the actions required to mitigate risk to the lowest practicable level. This provides a view to the predicted timing at which failures in the future will start to overwhelm EGD's ability to manage leak rates and the general safety and reliability of the system. This in turn informs the response required to manage long term asset condition. Each distribution riser material type has specific concerns associated with current and future condition findings.

Steel Risers

Figure 5.2-52 shows the projected failure rate for distribution risers increases at an average annual rate of 7%. The response associated with the volume of failure growth over the next 10 years is considered manageable.

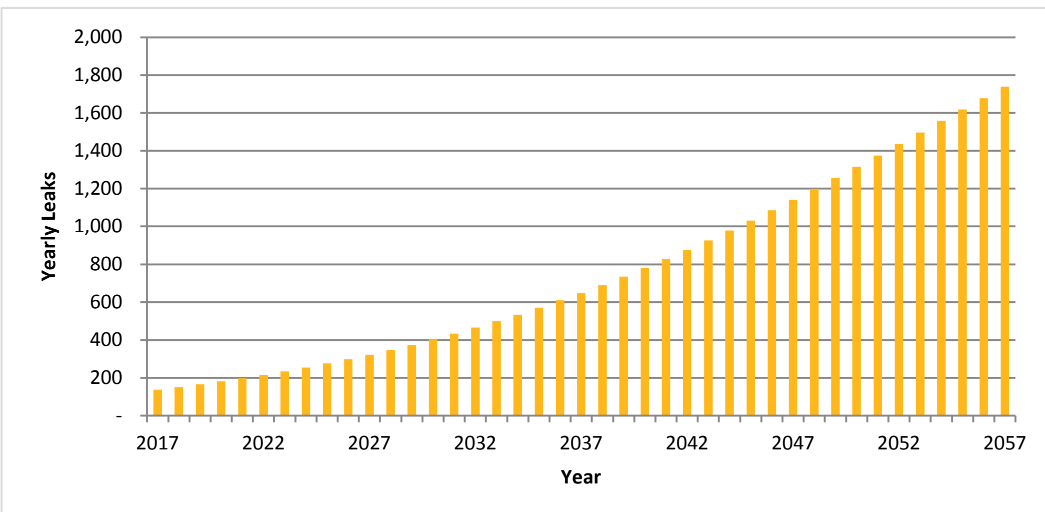


Figure 5.2-52: Leak Projections for Steel Risers

The current asset health of steel risers is considered to be relatively good. The failure mode of this asset involves the loss of containment along the riser due to corrosion, resulting in pinholes developing over time because of poor coatings or inadequate cathodic protection. It is estimated that the steel riser failure rate will increase over the next 40 years, which will continually monitored.

Plastic-in-Conduit Risers

Figure 5.2-53 shows the projected failure rate for plastic-in-conduit risers increases slightly over time at an average rate of 7% over a 40-year period. The quantity of annual leaks due to the plastic riser failure is considered to be inconsequential at this time.

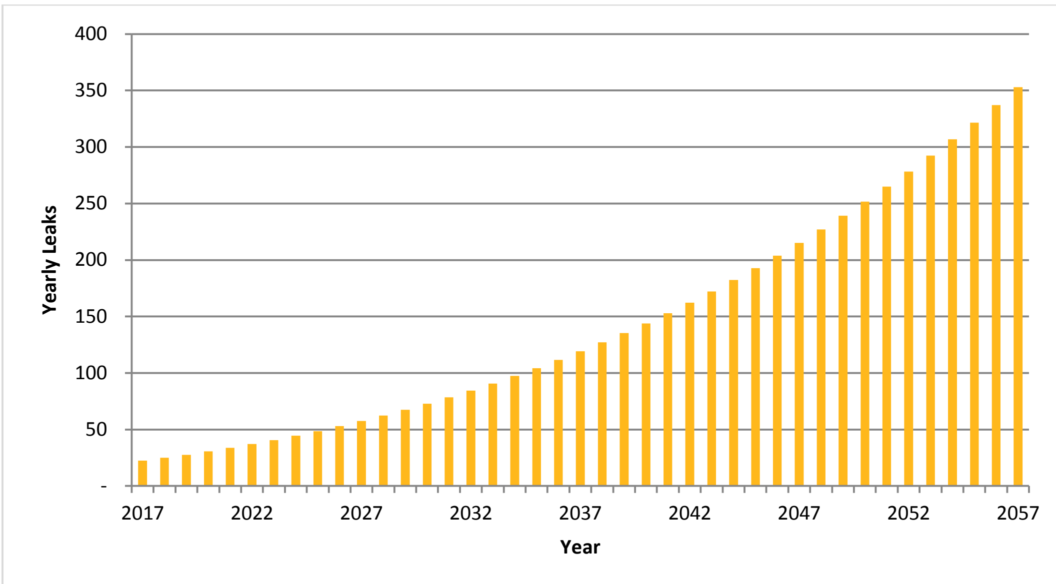


Figure 5.2-53: Leak Projections for Plastic-in-Conduit Risers

The current asset health of plastic risers is considered to be relatively good. The failure mode of this asset is degradation and cracking of the plastic from exposure to ultraviolet rays caused by corrosion and degradation of the carrier conduit. Leak projections anticipated over a 40-year period show that the plastic riser failure rate will increase over the next 40 years but cumulative failures are not expected to exceed 8,700 over this timeframe. It is expected that responding to the projected failures is considered manageable.

Anodeless Risers

The majority of anodeless risers used in EGD's distribution network are at the beginning of their projected end-of-life. Current data is not sufficient to demonstrate how they will fail as they age. Failures observed on anodeless risers have occurred due to damaged coatings, leading to corrosion (see **Figure 5.2-54**). Over the next 40 years, the projected failure rate is estimated to increase at an average rate of 10% annually over a 40-year period. In the short term, the number of failures is considered manageable. In the longer term, it is anticipated that the number of failures may challenge EGD's ability to manage the safety and reliability of the system. EGD continues to monitor these failures to determine if a proactive maintenance and replacement program is required.

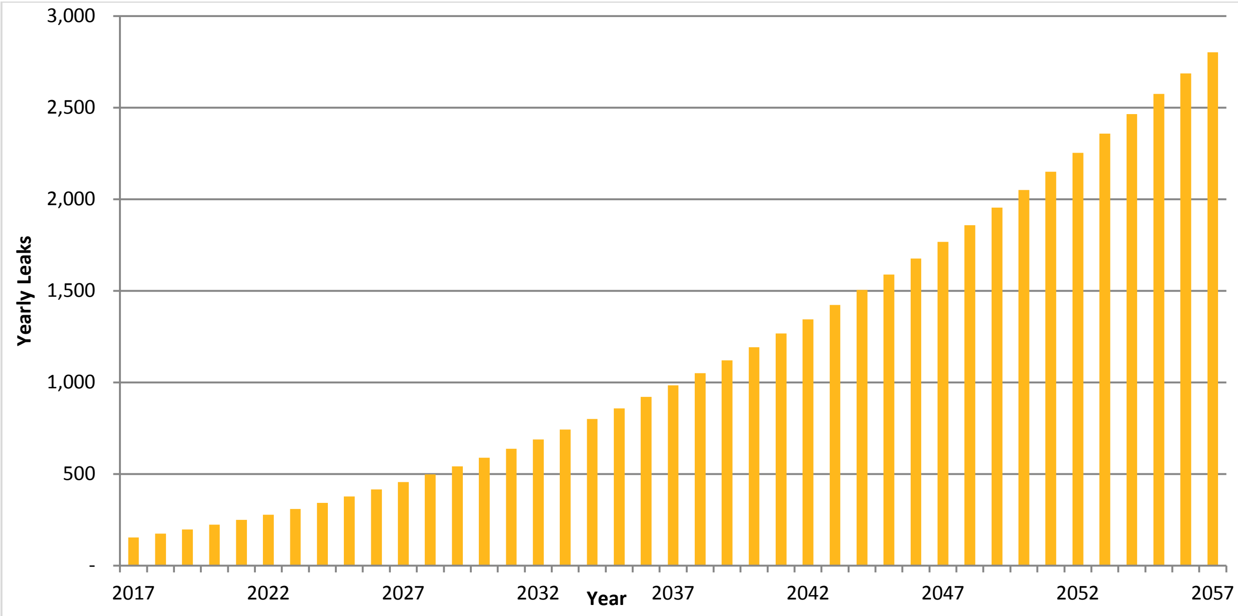


Figure 5.2-54: Leak Projections for Anodeless Risers

Copper Risers

In general, leaks on the distribution system are detected either by the public or through EGD's leak survey program, designed to detect leaks before they reach a high concentration. The entire population of copper services is surveyed every five years, with a portion of the population surveyed annually. This results in a leak projection model (**Figure 5.2-56**) that renders a wave shape (indicating discovered leaks).

The copper riser's AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure to occur, which manifests itself into a pinhole or a circumferential crack (see **Figure 5.2-55**). All sampled copper risers have shown some degree of corrosion after the AMP fitting. Based on the sampled risers and statistical modelling, it is expected that all copper risers will corrode, causing a leak at some point in their lifetime. Over the last several years, additional samples were collected to compare against initial results. The newly collected samples confirmed the expected copper riser behavior exhibited in the initial assessment - all copper risers were experiencing internal corrosion. The statistical modelling for copper risers was refined to improve model accuracy and understanding of riser long-term behavior.

The predominant failure mechanism for copper risers at EGD is associated only with internal pipe conditions and is not affected by external conditions or the environment. Analysis determined that turbulent flow will be reached in copper risers at pressure as low as 5 PSIG at 30,000 BTU. The average furnace uses between 70,000 BTU to 100,000 BTU. A typical gas water heater uses between 36,000 BTU to 66,000 BTU. This supports the sampling which showed wall loss on all copper risers, as turbulent flow can be reached at such low pressure from standard home appliances. The localized corrosion failure is illustrated in **Figure 5.2-55**.

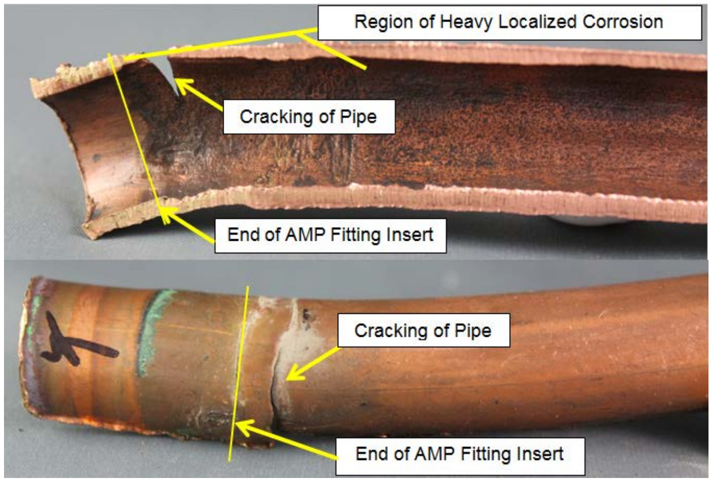


Figure 5.2-55: Localized Corrosion Failure at AMP Fitting Outlet

The condition of copper risers is expected to significantly degrade over time with an expected yearly increase in the number of leaks over the next 10 years. Actual failure data has trended very closely to the statistically projected number of leaks as seen in **Figure 5.2-56**.

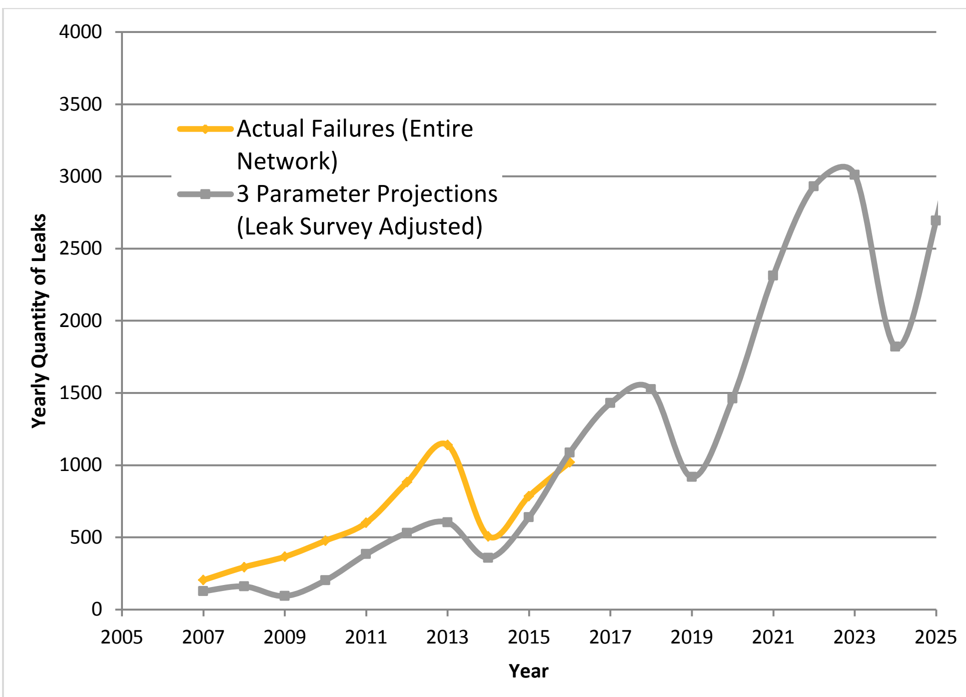


Figure 5.2-56: Copper Riser Discovered Leaks

Based on the Asset Health Review and leak projection charts, it is expected that the majority of copper risers will fail after 2037. The degradation of the asset is significant, easily outpacing current leak quantities over the next 10 years. Due to the very large numbers of projected leaks in a given year, a replacement program is required to manage the risk this asset presents to the public.

The current proactive replacement program replaces 4,000 copper risers per year, however, it is still expected that the annual rate will increase significantly. **Figure 5.2-56** demonstrates the number of expected leaks discovered on a yearly basis - the annual proactive replacement of 4,000 copper risers can still significantly reduce the expected number of leaks against a program where no proactive replacement is completed.

The condition of the copper risers is degrading significantly over the next two decades, which will result in a large number of leaks. Based upon long-term condition of the asset, a proactive program is required.

5.2.8.3 Risk and Opportunity

Riser failures occur when pressurized gas is released due to degradation of the asset. Failures vary by material type:

- Steel riser failures generally occur as pinhole leaks.
- Plastic-in-conduit riser failures generally occur as cracks in the plastic.
- Anodeless riser failures generally manifest from damages and subsequent corrosion.
- Copper riser failures generally occur as pinholes or circumferential cracks.

Risers are the transition between the below-ground service and the above-ground meter. The impact associated with failures may vary, depending on failure location. Risers are the closest underground gas infrastructure to a building. If the leak is below- ground, there is a more direct path to the building foundation and an increased chance of migration. If the leak is above- ground, there is the potential for migration directly into the premises through venting, open windows, or through appliance intakes. If there is a source of ignition within the area of the migration path, natural gas that migrates into a building has the potential to create a gaseous and potentially explosive environment which poses personal safety risks. The most likely event is for the gas to vent above-ground where it can be detected and reported by the public.

The risks and consequences associated with potential failures on distribution risers are described in three categories: safety, financial, and customer satisfaction. In addition to safety risk associated with gas migration as described below, EGD would be exposed to financial risk due to repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damage caused by the fire or explosion related to the gas accumulation and ignition. Due to the costs associated with reactive replacements of copper risers, the primary risk driver for copper risers is financial risk. Customer satisfaction risks identified are associated with GHG emissions, environmental impact, service interruptions, and reputational damages.

5.2.8.4 Strategy

The preferred life cycle management strategy for steel, plastic, and anodeless risers is to continue condition-based monitoring through the existing Leak Survey and Corrosion Survey programs, replacing risers when leaks are detected. Risers are also replaced when damaged by a third party, or as part of a mains and services replacement or relocation projects. Specific replacement programs will be executed to address issues such as isolated steel services and poorly performing copper services, along with the associated risers. However, other service assets will be replaced on a reactive basis, replacing the riser at the same time.

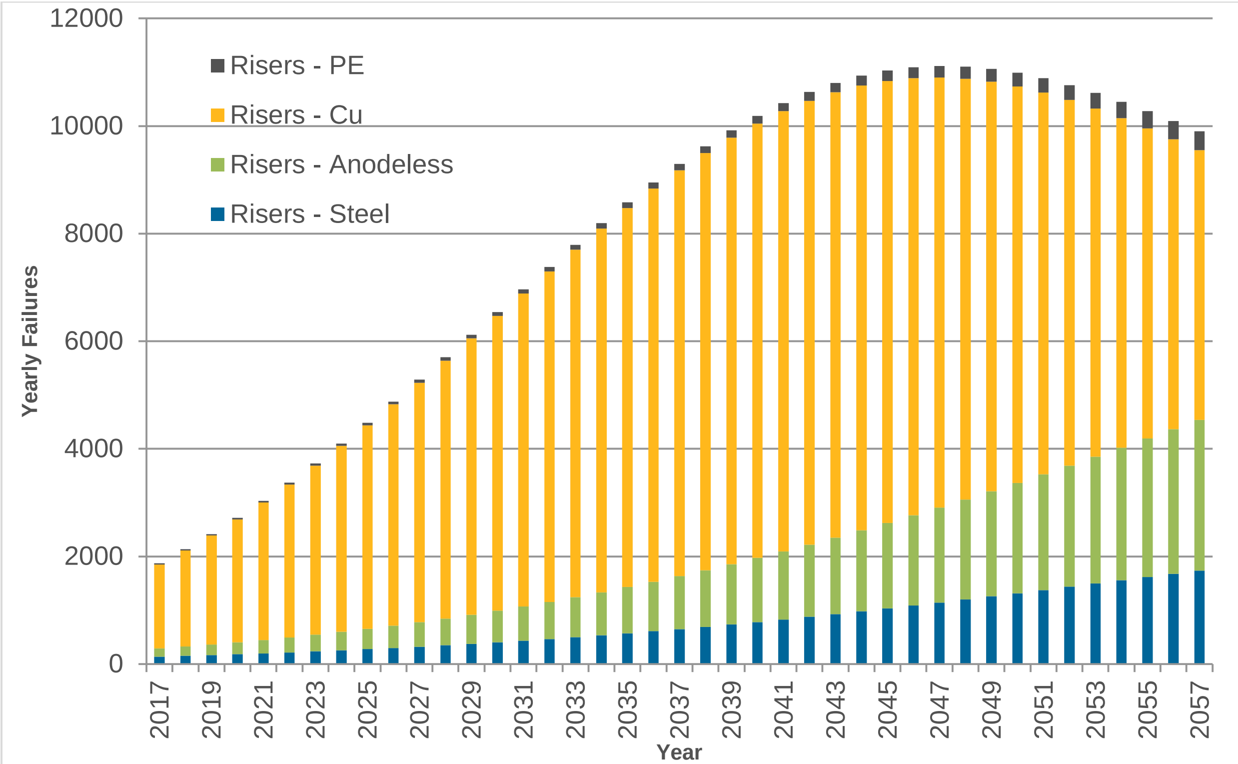


Figure 5.2-57: Leak projections for Risers

As seen in leak projections for the various types of risers, copper risers have the highest current leak volume and its projected leak rate increase is considerably more than all the other types of risers. For this reason, the life cycle management strategy for copper risers is a focused, proactive replacement program to ensure EGD's ability to respond to the number of copper riser leaks is manageable. Combined with copper risers that will be replaced through the Vintage Polyethylene Replacement Program, the proactive replacement of copper risers will reach 12,000 units per year in 2024. The replacement pace for succeeding years will increase to 20,000 units annually.

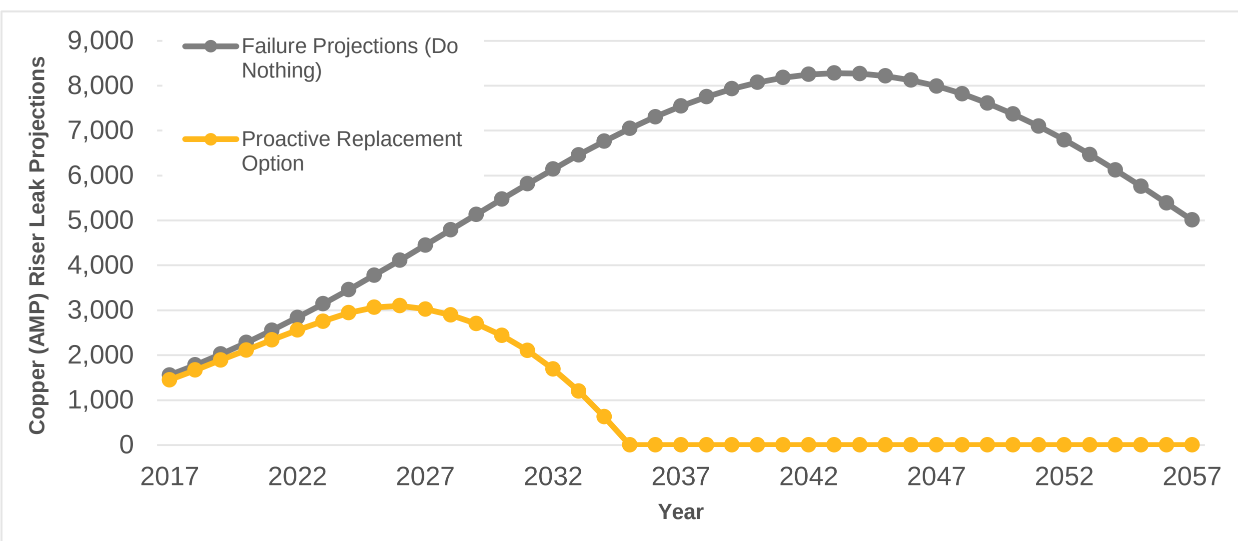


Figure 5.2-58: Copper Riser Leak Projection – Reactive vs Proactive strategy

EGD continues to evaluate asset condition and adjust its strategy accordingly to manage the integrity of distribution services. Safety is the foundational component of managing all gas carrying assets. In the shorter term, the current annual service replacement program continues to manage the failing and non-compliant riser assets. Risers continue to be monitored under the leak survey and corrosion survey programs to ensure the assets are not leaking. In the longer term, when the failures transpire as projected, targeted replacement programs will be developed to manage risk to the lowest practicable level. The approach is expected to have an insignificant impact on customer satisfaction, but may impact operational reliability over the longer term.

5.2.9 Valves

Gas valves are mechanical devices in the distribution system that provide the means to isolate gas main damage, control gas flow, achieve load shedding, and stop gas flow to facilitate maintenance and construction activities (such as fitting cutout and gas main tie-ins). Understanding valve condition allows for the safe and efficient execution of these necessary operations. Valves are monitored regularly under the Valve Inspection and Maintenance Program for accessibility and operability. Failures over the years have been related to valve corrosion, inoperability, and leaks found at the mechanical components of the valve.

Occasionally these valves can be repaired in-situ, but often require replacement due to the complexity of repair. **Figure 5.2-59** shows the age profile of system valves is relatively flat, with a spike in older steel assets between 43-63 years of age, reflecting the age distribution of the parent steel mains.

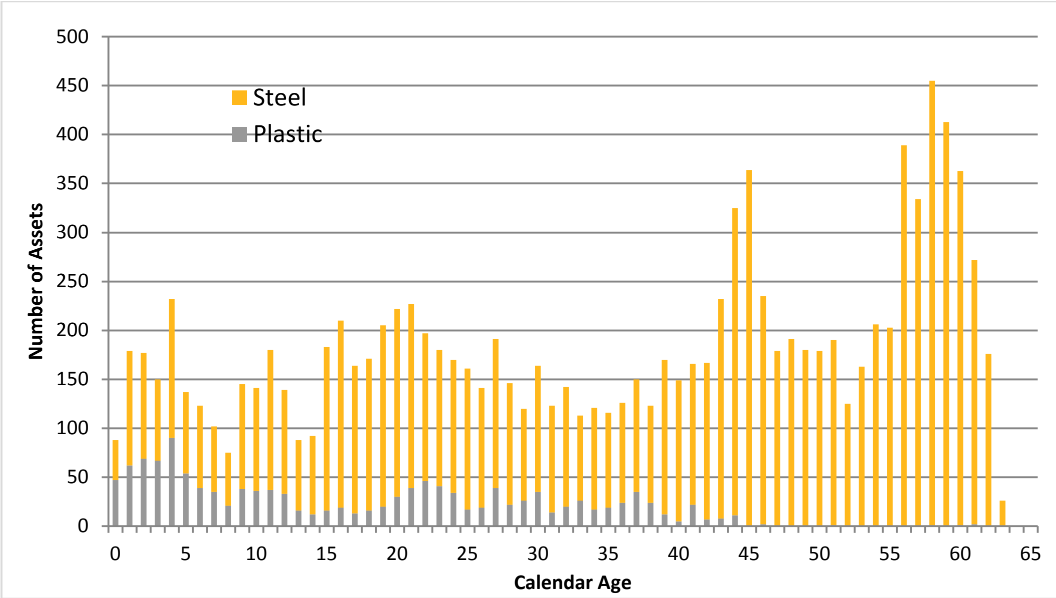


Figure 5.2-59: Valve Age by Material

Mainline valves are classified into four types to reflect the different failure mechanisms as each type has a different design and application:

- **Ball Valve**: A ball valve uses a hollow, perforated, and pivoting ball to control gas flow. The valve opens when the ball's hole is in line with the flow. It closes when pivoted 90 degrees by the valve handle.
- **Plug Valve**: A plug valve is shaped like a cylinder or cone and can be rotated inside the valve body to control flow.
- **Gate Valve**: A gate valve is a linear motion valve in which a flat closure slides into the valve body to restrict flow.
- **Unknown**: Known installed valves in the EGD system without valve type identification.

5.2.9.1 Condition Methodology

Asset health for valves has been evaluated using the performance history of the asset through failure data over a 10-year period. Valve failure is defined as a leak or a failure to operate. The projection model only takes into consideration time-dependent failures (i.e., leaks) - failure to operate is excluded in the model since valves are repairable or replaceable assets. To the extent possible, repair would be considered an attempt to remedy a valve failure. A valve replacement is usually performed when the valve repair is unsuccessful. In this situation, the Non-Homogeneous Poisson Process (NHPP) model is understood to be an appropriate model to evaluate and predict the performance of this asset over time.

5.2.9.2 Condition Findings

In evaluating asset health, EGD is interested in the current baseline health and the degradation rate over time. The degradation rate and subsequent failures inform the actions required to mitigate risk to the lowest practicable level. This provides a view to the predicted timing at which failures in the future will start to overwhelm EGD’s ability to manage leak rates and the general safety and reliability of the system. This in turn informs the response required to manage the long term asset condition.

The current asset health in the Asset Health Review of valves is considered to be relatively good. The failure mode of this asset is loss of containment or failure to operate. The leak projections anticipated over a 40-year period is for the failure rate of all known valve types to increase and cumulative failures to exceed three failures over this timeframe.

5.2.9.3 Risk and Opportunity

Valves are used to enable system maintenance, perform load shedding and isolate pipelines in the event of emergencies. When valves fail to operate, other methods are used (squeezing off mains in the event of damages or using valves located further than required). These other methods could result in delays, resulting in greater volumes of gas blow-offs and broader customer outages.

The risks and consequences associated with potential failures on these assets are described in three categories: safety, financial, and customer satisfaction. EGD is exposed to safety risk due to prolonged gas leaks that could potentially migrate through underground infrastructures into building, resulting in gaseous and potentially explosive environment. Financial loss is possible due to total repair costs, commodity loss, relighting customer gas appliances, any property damage caused by a gas leak ignition. Customer satisfaction risk identified is associated with GHG emissions, environmental impact, customer outages, and reputational damages.

5.2.9.4 Strategy

Valves continue to be monitored through the leak survey and valve inspection programs and will be replaced or repaired when leaks are detected, or if the valve becomes inoperable. Valves are also replaced as part of a mains replacement or relocation program. These assets will be replaced on an as-needed basis if they begin to leak, and the Plan-Do-Check-Act process will form the basis of the development of a targeted replacement program should the failure rates increase significantly.

The preferred life cycle management strategy for valves is to manage failures on a reactive basis as they fail. This could be a repair or a replacement depending on the root cause, and whether the valve can be repaired in-situ. This strategy is augmented with the removal of some of the oldest valves through the strategies described for vintage steel mains.

Beyond managing the condition of valves, strategic supply mitigation initiatives are focused on addressing system reliability as it pertains to gas supply disruptions. These disruptions manifest themselves through a loss of supply or pressure reductions. In the case of supply issues, the demand on the system must be removed in a controlled and systematic manner to minimize the supply interruptions to the extent possible. Control is executed in the following ways:

- Through the use of strategically-placed valves within the distribution system to create manageable isolation areas which will minimize supply impact to critical areas
- Securing multiple feeds to large single-sourced networks, where damages to critical supply lines can isolate entire towns

EGD continues to manage system reliability to ensure that customer impact is minimized to the lowest practicable level.

5.2.10 Technology

Technological innovations enable EGD to enhance the safe and reliable supply of natural gas to customers. These innovations are applied to existing materials, practices, and/or procedures and allow EGD to mitigate and eliminate risk and improve system operation. Technological innovations increase the efficiency and productivity of existing programs. EGD maintains a prudent approach to capital spending by using North American consortiums to leverage investments for research, development, and implementation of new technology. These innovations and sensible use of capital support Asset Management principles and will allow EGD to evolve.

5.2.10.1 Risk and Opportunity

Partnering with collaborative innovation groups, such as NYSEARCH and the Operations Technology Development (OTD) of the GTI allows EGD to adopt an economical approach to spending by leveraging its resources with those of other member organizations. This partnership also allows EGD to gain insight into technological innovations and ensure that the solutions are aligned with EGD's objectives. Some current initiatives that EGD is supporting through OTD and NYSEARCH include:

- **Biomethane data collection project**: Information and data from active renewable natural gas plants will be collected so that gas distribution utilities will have a better understanding of the use of renewable natural gas
- **Non-thermal infrared gas imaging**: Technology for imaging methane as it disperses above-ground.
- **Excess Flow Valve (EFV) evaluation and analysis in extreme temperature environments**: Performance analysis of EFVs in cold temperature installations and recommendations for improved operation.
- **Evaluation of meter set placement and clearances**: Evaluation of leaks at meter sets and gas concentrations in relation to critical building features
- **Minimum recover time for Polyethylene pullback**: Development of guidelines to understand and predict recovery time required for polyethylene pipe after pullback during trenchless installations (such as horizontal direct drilling).

Fibre Optic Monitoring

Fibre optic monitoring is a key initiative for installation along new construction pipelines and has many advantages. The natural gas industry is constantly seeking new or enhanced techniques to address the issues of third-party intrusions and damage to the distribution pipelines. Majority of techniques used to monitor pipelines use an approach (e.g., an aerial survey) where the system is assessed on a periodic basis, resulting in an instantaneous view or snapshot of the system to detect intrusions and pipeline leaks. However, new technologies are now commercially available and are being considered by many organizations for real time pipeline monitoring.

Mechanical damage caused by unauthorized third-party excavations is the most significant threat to pipeline safety, having the highest probability of occurrence and highest probability of damage. Threats of this type are described as time-independent or may fall under human error. The scope of this program focuses on installing fibre optic monitoring technology on vital and critical mains. In addition to the ability to detect unauthorized intrusions and potential threats from mechanical and manual excavation, fibre optic monitoring technology can also detect leaks that may occur along pipelines, and track pigging equipment as it travels along a pipeline segment.

Fibre optic sensing systems operate and serve up information in real time. Incident response capacity and quality will be superior to the current practice, since EGD will be able to detect and quickly respond to unauthorized third-party activity or intrusions. EGD will also have the ability to pinpoint leak locations, improving public safety and reliability.

5.2.10.2 Strategy

EGD continues to seek efficiencies, best practices, and innovations to evolve the business. A roadmap for the Research and Development Stream under Engineering has been developed in 2018 to further integrate innovation projects within the business and to consistently select and rank initiatives of interest.

5.2.11 System Reinforcements

System Reinforcement projects involve the installation or modification of existing gas distribution assets to maintain minimum required system pressures, maintain distribution capacity, and meet growing natural gas demands. These projects are primarily driven by increased customer demand, customer growth and system reliability considerations.

This strategy fosters long-term system reliability and the ability to serve existing and forecasted customers during peak design temperature conditions. Reinforcement is determined based on (but not limited to) customer growth, identification of system low pressure points, and capacity constraints. Failure to implement reinforcement projects in a timely manner could potentially lead to an inability to support future customer growth.

As part of the asset planning process, the Network Analysis department establishes reinforcement need and timing for EGD operating areas, ensuring the system meets anticipated peak hourly demand. Load additions to the system are modelled based on the design temperature in **Table 5.2-6**.

Table 5.2-6: Temperature Criteria for Load Additions

TEMPERATURE REGION	DESIGN TEMPERATURE	DEGREE DAY
Peterborough and Lindsay (Area 40)	-28°C	46
Georgian Bay and Barrie (Area 50)	-26°C	44
Ottawa Area (Area 60)	-29°C	47
Greater Toronto Area (Area 10,20,30)	-23°C	41
Niagara Area (Area 80)	-21°C	39

Note: Design temperature is the average temperature on the peak day.

5.2.11.1 Forecast Methodology

Identifying Purpose, Need, and Timing of Reinforcements

The Network Analysis department completes three major functions as part of planning for reinforcements: Load Gathering and Simulation, Annual Forecasting, and Long Range System Planning.

EGD builds and validates piping system models based on actual field conditions and uses pipeline simulation software to simulate pressures and flows based on customer usage data. Short- and long-term forecasted growth is incorporated into these models to predict system performance.

Load Gathering and Simulation*:* Load gathering extracts actual billed customer consumption data and matches it with locally recorded temperatures, providing EGD with a reliable, repeatable, and predictable method for estimating an individual customer's peak hourly demand. Based on temperature inputs and estimated customer consumption, the base and space heating load demand for each customer is determined and assigned to selected points within the models. For large volume customers, loads are input based on measured hourly consumption and contractual parameters.

The simulation aims to compare calculated performance (pressures and flow rates) of the model versus the actual performance of the system after each winter heating season. Key system settings (i.e., station outlet pressures) in the model are adjusted to simulate actual field conditions on the selected day. The resultant pressure and flow information from the model is then compared to actual field chart or recorder readings throughout the gas distribution system.

Annual Forecasting: Based on the Load Gathering and Simulation model, additional customer loads forecasted for the upcoming heating season are subsequently added. Overall system pressures and station flows are assessed to ensure all minimum pressures are maintained and all stations are operating within design parameters. Locations that are approaching minimum system pressure are selected for pressure monitoring - in some cases reinforcements may be required.

Long-range System Planning: The long-range system planning process considers a minimum of 10 years of customer growth to ensure the adequacy of system performance over the long term. Growth projections are obtained based on information from builders, developers and municipalities, projections based on external experts, and information based on housing starts and other economic factors (e.g., GDP growth, employment rates etc.). The reliability of the system is dependent on maintaining minimum system pressures and ensuring capacity is available to support customer growth. Reinforcement solutions are considered if minimum system pressure requirements cannot be maintained with forecasted loads applied. Each of the reinforcement segments identified is evaluated on a case-by-case basis considering any or all of the following: existing system capacity, system redundancy or looping, operating pressure, past operational history, integrity, constructability, cost, environmental impact, and future expansion or development potential.

Reinforcement solutions are based on the best available information at the time long-range system planning activities are performed. Many variables may change the need, timing, or scope of the reinforcement solution. For example, growth may occur earlier or later than forecasted, which may change the timing of the reinforcement.

5.2.11.2 Forecast Findings

The long-range system planning activities identified a list of reinforcement projects to sustain the forecasted 10-year customer growth identified in the Customer Growth Asset class (see **Section 5.1**). The forecasted customer growth may be added to the distribution system provided required reinforcement infrastructure has been installed.

The Network Analysis department determines the need, timing, location and scope for system reinforcement and quantifies the benefits of the reinforcement using historical and forecasted pressure and capacity at stations and at low points in the system. The Network Analysis department leads the development of the required reinforcement project scope and engages stakeholders such as Operations, Engineering, Risk, and Asset Management to discuss outcomes.

Each reinforcement project is summarized in a project brief that details the following:

- **Project Purpose/Need/Timing:** Identification of key drivers affecting the need for the reinforcement, when and where forecasted pressure and capacity constraints will occur, and when the solution is required.
- **Project Benefit:** Overall benefits (quantitative and qualitative) resulting from the proposed system reinforcement include:
  - Security of supply
  - Ability to connect future customers
  - Pressure and capacity benefits achieved
  - Length of time the reinforcement benefits will last before further reinforcement may be required.
  - Benefits to system reliability
  - Benefits of addressing frost heaving concerns due to large pressure differentials
- **Identification and Evaluation of Project Alternatives**: In addition to the proposed scope, the project brief provides details on other feasible options that may provide similar benefit:
  - Pressure increases
  - Looping strategies that enable multiple network feeds, enhancing system reliability
  - Upsizing of existing pipe, or localized reinforcements to eliminate system bottlenecks
  - Existing station rebuilds or addition of new stations
  - Flow biasing
  - Project phasing over time
- **Project Risks if Not Completed:** Description of potential risks to the system if piping is not in service during load additions (e.g., insufficient capacity, pressure drops etc.)

5.2.11.3 Risk and Opportunity

Reinforcement projects, which include projects being developed for security of supply and system reinforcement, are governed by the *EBO 188* report. A key principle of the guidelines states that existing ratepayers should be held harmless from the rate impact resulting from the cost of new connections. **Section 5.1.2** provides further details on the *EBO 188* guidelines for feasibility purposes.

A preliminary feasibility analysis was conducted on the reinforcement projects using cost estimates, forecasted customer additions, and discounted cash flow assumptions. This analysis determined the aggregate cost-benefit ratio for all the reinforcement projects that were proposed as part of the Long Range Plan. On aggregate, the projects proposed in the Long

Range Plan were in the acceptable feasibility range for inclusion in the Asset Plan. Individual projects will undergo a detail feasibility analysis prior to construction to ensure alignment with the *EBO 188* requirements.

Additionally, reinforcement projects are risk assessed through a QRA process. The QRA process can provide additional information on risks and opportunities associated with reinforcement projects. For example, the QRA can quantify risk reduced by improving system reliability through diversity of supply, and quantify the forecasted financial opportunities foregone without reinforcement. The QRA also helps in optimizing the reinforcement project alternatives proposed by Network Analysis.

5.2.11.4 Strategy

The strategy for system reinforcement is to implement specific reinforcement solutions in a timely manner to enable forecasted customer growth. The specific drivers and solution details for reinforcement initiatives can be found in the Appendix.

The company continues to review the distribution system supply and demand requirements through the regular Long Range Planning process, along with continuous system monitoring. The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes.

5.2.12 Pipe Capital Expenditure Summary

The summary of projects and programs under the Pipe asset class accounts for $1.1B from 2019 to 2028, as summarized in **Table 5.2-7**. The Pipe capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.2-7: Pipe Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-year Forecast
Steel Mains Replacement	18,844	21,599	24,117	26,929	30,068	33,574	37,489	41,859	46,740	52,189	333,408
Corrosion Prevention Program (Anode Replacement)	1,211	1,229	1,247	1,265	1,284	1,303	1,323	1,342	1,362	1,383	12,949
Pipe Emergency Replacement	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	20,000
Major Pipelines	25,401	2,600	9,240	40,642	2,650	10,750	600	-	-	-	91,882
NPS 30 Don River Replacement	24,901	800	-	-	-	-	-	-	-	-	25,701
Martin Grove Replacement Phase 2	-	-	-	-	400	10,750	600	-	-	-	11,750
KOL – Parliament St. to Bathurst St.	250	1,650	-	-	-	-	-	-	-	-	1,900
St. Laurent Replacement	250	150	9,240	40,642	2,250	-	-	-	-	-	52,532
Vintage Plastic Replacement	1,889	2,276	2,746	3,319	4,018	4,870	5,910	7,178	8,726	10,615	51,546
Relocations	16,017	27,006	10,550	9,700	9,700	9,700	9,700	9,700	9,700	9,700	121,473
Engineering Technology	-	1,358	1,093	1,382	583	-	-	-	-	-	4,415
Integrity Retrofits	3,855	-	-	-	-	-	-	-	-	-	3,855
Service Relay Blanket	17,723	20,296	21,195	22,175	23,183	24,261	25,233	26,223	27,236	28,252	235,777
Copper Riser Replacement Program	4,407	4,483	6,841	9,279	10,840	13,005	19,539	24,846	25,276	25,713	144,227
Reinforcements	20,332	13,167	5,193	4,924	11,602	16,728	18,912	2,845	504	-	94,207
Ajax Reinforcement	-	160	3,052	-	-	-	-	-	-	-	3,212

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-year Forecast
Amaranth System Reinforcement	-	-	100	100	-	4,947	-	-	-	-	5,147
Barrie to Collingwood XHP Pressure Elevation	-	-	-	-	-	-	7,723	-	-	-	7,723
Bathurst Reinforcement	8,811	650	-	-	-	-	-	-	-	-	9,461
Clarence Rockland XHP	-	-	-	-	-	95	7,475	-	-	-	7,570
County Rd 9 Reinforcement	-	-	-	-	-	3,052	-	-	-	-	3,052
Erin IP System Reinforcement	1,454	-	-	-	1,711	-	2,778	-	-	-	5,943
Kemptville Reinforcement	-	-	-	186	4,839	-	-	-	-	-	5,025
L'Original Reinforcement	173	3,897	-	-	-	-	-	-	-	-	4,069
McCowan Ave HP Reinforcement	-	30	534	60	-	2,374	-	-	-	-	2,998
Peterborough Reinforcement	50	2,072	-	-	-	-	-	-	-	-	2,122
Thornton XHP Reinforcement	-	-	-	1,835	3,633	-	-	-	-	-	5,468
Welland IP NW 8925 Reinforcement	1,669	832	-	-	-	-	-	-	-	-	2,501
York Region Reinforcement	2,522	70	-	-	280	6,260	-	-	-	-	9,132
Reinforcements <$2M	5,653	5,456	1,508	2,744	1,138	-	937	2,845	504	-	20,785
Pipe Total	**111,678**	**96,013**	**84,222**	**121,615**	**95,928**	**116,190**	**120,705**	**115,993**	**121,543**	**129,852**	**1,113,739**

Refer to **Section 6.3** for projects with expected spend that are not included in the capital summary.

5.3 STATIONS

The Stations asset class is comprised of facilities and assets designed to accurately regulate and measure natural gas flowing through the gas distribution network. Station assets possess regulating and pressure-reducing components that monitor and analyze gas flow volume and delivery. These components control pipeline pressure reduction between pipeline networks with different operating pressures and ensure the safe and reliable distribution of natural gas.

The Stations asset class is comprised of approximately 17,000 sites throughout Ontario. This includes all natural gas entry points into the EGD distribution network, control points throughout the network, and delivery points to end-use customers.

The Stations asset class is categorized by station type and station components (**Figure 5.3-1**). There are five types of stations:

- **Gate Stations** accept gas from a transmission company's pipeline and supply gas to the distribution system, acting as the custody transfer and entry points of natural gas into the gas distribution network. Station components included in gate stations are pressure control, odourization, measurement, station valves, heating, and telemetry. Gate stations typically accept incoming gas pressures from the transmission company between 4,480 and 6,890 kPa and regulate to distribution pressures between intermediate pressure (IP) (440 kPa) and extra high pressure (XHP) (4,500 kPa). In a particular location, a single gate station can supply gas to over 600,000 customers.
- **Feeder Stations** are large regulator stations located within the gas distribution system. Station components included in feeder stations are pressure control, measurement, gas pre-heating, and telemetry. Feeder stations typically accept incoming gas pressures from EGD XHP pipelines at pressures up to 4,500 kPa and regulate pressures to high pressure (HP) (1200 kPa). This type of station is traditionally located within the GTA.

The majority of gate and feeder station sites have above-ground components, with some piping and operating equipment located below-ground. All gate and feeder station sites are located on EGD-owned property within fenced and controlled access compounds.

- **District Stations** operate within the gas distribution network and regulate the flow of gas from a higher pressure (up to XHP 1200 kPa) to a lower pressure (IP-440 kPa, MP-100 kPa, or LP-14 kPa). District stations are primarily used for pressure control and may have gas pre-heating system and telemetry functions. These stations are typically located within roadway allowances and are housed within a box enclosure, are located above-ground without an enclosure, or are buried below-grade in a vault.
- **Header Stations** accept gas from any EGD pipeline system and feed a header service (a network of pipe on private property). Header stations are primarily used for pressure control.
- **Sales Stations** accept gas from any pipeline system to feed a single customer with a total connected load greater than 12 m3/h, or with a delivery pressure to the customer of 14 kPa or greater. Sales stations are used for pressure control and gas measurement.

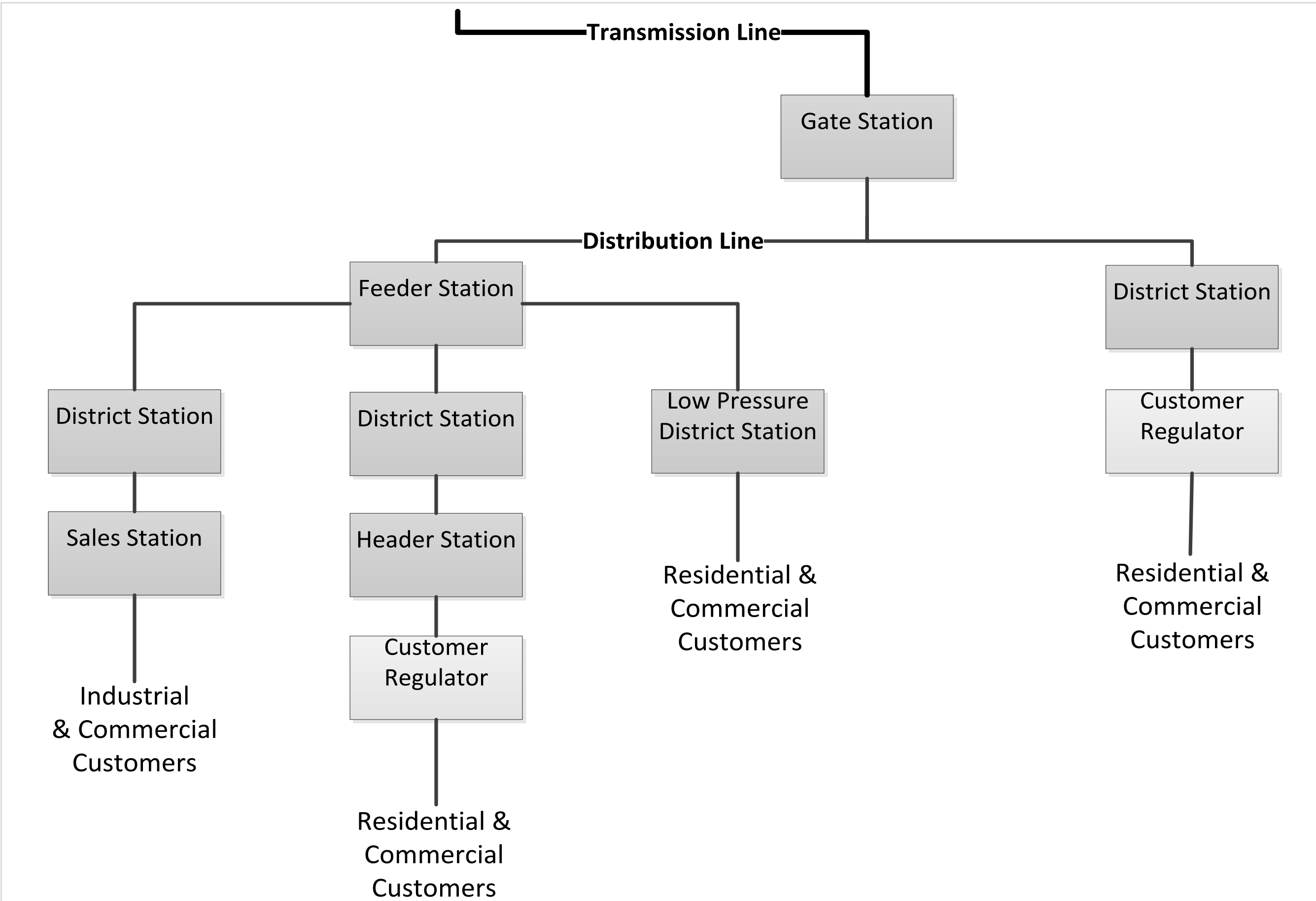


Figure 5.3-1: Station Hierarchy by Type

The Stations Asset Class includes the following asset component sub-systems:

- Pressure Control
- Station Valves
- Piping Systems
- Heating System (Boilers and Heat Exchangers)
- Telemetry System
- Odourization System
- Measurement System
- Integrity Assets
- Civil and Site Assets

The **Pressure Control** components control and regulate gas pressure from a higher pressure (inlet pressure) to a set lower pressure (outlet pressure). Pressure control equipment typically consists of operator regulators, monitor regulators, relief valves, and slam-shut devices. Operator regulators control pressures while monitor regulators provide over-pressure protection in the event the operator regulator fails. Regulators are classified into four types: pilot-operated boot, pilot-operated non-boot, spring type regulators, and pilot-operated control valves. Relief valves provide an audible and odor notification in the event of operator regulator malfunction. EGD's design standards mandate a minimum of two regulator runs (an operator regulator and a monitor regulator per run) with the ability to have one regulator run as redundant.

The **Station Valve** components control the flow of gas through the station, and include all inlet valves, outlet valves, bypass valves, and component isolation and process valves. Station valves are used to direct flow, isolate station components, and shut down gas supply for planned or unplanned events.

The **Piping System** within stations is comprised of the pipe connecting each of the component groups, as well as ancillary piping and tubing. Ancillary piping includes glycol piping for the heating system, tubing for pressure control, and piping and tubing for the odourization system. Piping may be installed below- or above-grade with pipe supports, and may be insulated to retain heat or for noise attenuation. Protection of the piping system consists of underground corrosion control systems and above-ground high performance coating and paint.

The **Heating System** components ensure that gas temperatures within the distribution system remain above 0^{o}C, as the reduction in temperature caused by pressure regulation can have detrimental effects on equipment performance. The heating system is comprised of two sub-components: the boiler and the heat exchanger. The pressurized boiler heats and circulates glycol through a glycol loop to the heat exchanger, which transfers heat to the gas prior to pressure control reduction. Heating systems may also comprise of small component heaters used for thermal protection of critical components such as regulators and pilots.

The **Telemetry System** components connect station components to a network that remotely transmits station performance information to Enbridge's Gas Control group in Edmonton, Alberta. Information such as inlet and outlet pressures and temperature, gas flow rate, odorant injection rate and other critical characteristics of the stations' performance are monitored in real time. Typical sub-components include:

- Programmable Logic Controller (PLC) / Remote Terminal Unit (RTU) as the central processor
- Pressure and temperature sensors and transmitters
- Gas monitors
- Communications devices and antenna towers
- Power supply, UPS and backup generators and other electrical assets
- Weather systems

The **Odourization System** components are responsible for the introduction of odourant into the gas stream to ensure gas is detectable at low concentrations. Odourant injection is automated at all gate stations to odourize natural gas in the distribution network. Sub-components of the odourization system include:

- Odourant tank
- Odourant pumps
- Injection point with sight glass
- Odourant containment
- Meters, valves, tubing, controllers
- Atmospheric monitoring devices
- PLCs

The **Measurement System** components provide a corrected volumetric measure of the amount of natural gas flowing through a particular site. Measurement devices are used in sales stations as a custody transfer point between EGD and the customer. EGD uses many different meter types (such as diaphragm meters, rotary meters, turbine meters, etc.) and electronic volume correcting equipment to calculate pressure and temperature compensation factors in real time.

At all gate stations and at certain feeder and district stations, EGD incorporates measurement devices to measure the rate of gas flow through its system. These measurement devices are critical for calculating the demand requirements (rate of odourant flow, heating system temperature requirements, etc.) for other component groups within station operations.

The odourization, heating, and pressure control systems use the rate of flow determined by the measurement system to calculate specific system demand requirements. The performance of the gas network is monitored by the Gas Control group for pressure and flow measurement. If there is a significant variation in flow demand, an alarm goes to the Gas Control group indicating an upset condition, which could indicate a leak in the network, upset conditions from other stations, gas delivery problems, or confirmation of gas delivery quantities from the transmission company through comparison of measurement values. The measurement system also provides insight and visibility into the overall performance and reliability of the gas distribution network. Real-time flow data is monitored by the Gas Control group using the telemetry system to meet contractual requirements, balance demands to achieve greater system reliability, and monitor the performance of the network against weather-dependent generated models to better anticipate and predict system supply problems.

Integrity Assets consists of equipment used for in-line inspections of Integrity mains within the TIMP. These assets are typically found at gate and feeder stations, and typically include an ILI tool launcher or receiver, filters, conditioning equipment, and associated piping.

Civil Assets at gate and feeder stations consist of individual buildings for housing telemetry assets, heating/boiler equipment, the odourization system, the pressure control system, and other miscellaneous equipment. Civil assets also include fencing, property lighting, security systems, piping supports and barriers, water management systems, such as culverts and ditches, and general property.

The stations asset class breakdown is illustrated in **Figure 5.3-2**.

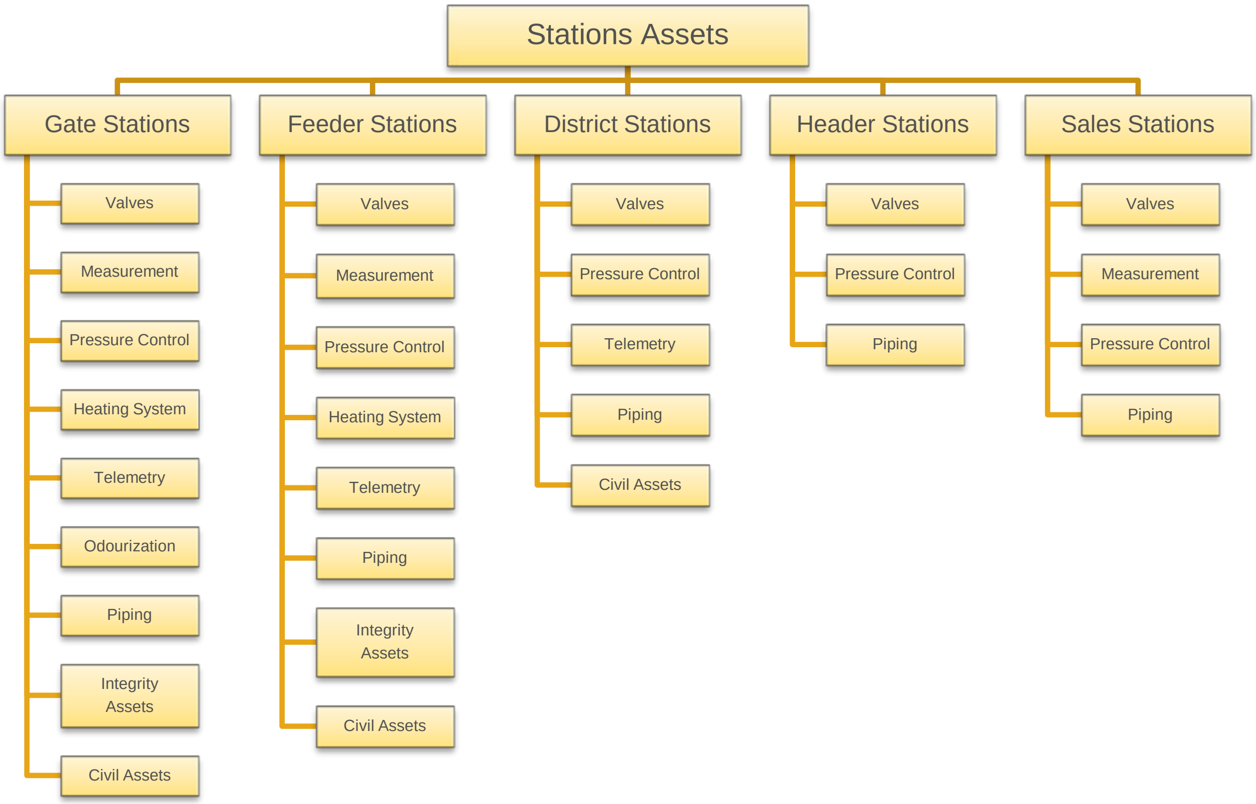


Figure 5.3-2: Stations Asset Classification

5.3.1 Stations Objectives

There are two categories of objectives for the Stations asset class: System Integrity & Reliability and Relocations.

Table 5.3-1: Stations Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
System Integrity & Reliability	Maintain distribution stations to meet or exceed codes, standards, and the requirements of applicable governmental authorities for safety and operational effectiveness.	• QA & QC closeout rate • Operator Qualification (OQ) score
	Reinforce existing distribution networks and monitor existing asset utilization to ensure the system has the capacity to reliably meet current and future customer demand.	• Forecasted number of stations which could have capacity issues through long range planning • Number of economically feasible customers added • Pressure monitoring – low pressure alarm management
	Ensure security of supply by enhancing the flexibility of the system to minimize disruptions from upstream supply issues or by addressing asset failures within the distribution system.	• Station utilization • Number of trouble calls • Number of service disruptions
	Utilize cost, risk and performance information to drive asset-related decisions.	• Risk mitigated and LRROI • QRA completion % • Number of trouble calls
	Continuously evolve the understanding of condition and risk associated with station assets.	• Material Fault Program o On-time Classification of faults o On-time Completion of corrective actions • Material Quality Assurance: Completion of Material QA • Quality Assurance: Number of audits completed • Collection of in-field condition surveys
	Ensure the safe and reliable delivery of natural gas to end users.	• Leak Management o Completion of Leak Survey Program o Completion of leak repair investigations • Corrosion Management: Completion of station inspections • Damage Prevention: Completion of aerial patrols • Odourant Management o Completion of sniff checks o Completion of odourant analysis requests o Completion of odourant survey test points

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
		• Operating Limit Management: Number of operating limit change orders completed on time • Station Operations o Completion of gate and feeder station inspection o Completion of district and downstream station inspection o Completion of SCADA/telemetry equipment inspection and calibration o Completion of SCADA point-to-point verification o Validation of the accuracy of M&R records
Relocations	Ensure station locations are in compliance with all governing authorities for location of existing assets.	• To be completed
	Relocate station assets to reduce or mitigate the impact of third party work on the safe and compliant operation of the distribution system.	• To be completed
	Recover costs allowed by municipal franchise and other agreements for relocations initiated by third parties.	• Number of past due cost recovery invoices

To achieve these objectives, asset investment decisions are governed by Life Cycle Management policies that are presented in **Table 5.3-2**.

Table 5.3-2: Life Cycle Management for Stations Assets

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Design the installation of station assets to: - Ensure the safe and reliable delivery of natural gas. - Ensure worker and public safety. - Ensure code compliance. - Meet current and future demand requirements. - Reduce risk to the lowest practicable level. - Ensure critical components and systems have multiple layers of failure protection. - Minimize environmental impact. - Ensure components can be made safe in a reasonable period of time. - Minimize future maintenance needs. • Procure materials to meet or exceed applicable codes, standards and policies. • Install station assets to meet or exceed codes, standards, designs, and procedures for safe and reliable operations • Create asset records to meet or exceed standards, policies, and procedures that are traceable, verifiable, complete, and correct.

LIFE CYCLE STAGE	ACTIVITIES
Utilize	• Operate the distribution system to: - Ensure the safe and reliable delivery of natural gas. - Ensure worker and public safety. - Meet or exceed compliance standards and established procedures. - Meet current demand. - Minimize end user disruption. - Utilize the assets in the most cost-effective manner. - Extend asset life. • Monitor the performance and utilization of station assets to inform future life cycle decisions. • Operate station asset systems to ensure they meet or exceed policies, codes, and standards.
Maintain	• Maintain integrity of assets to minimize loss of containment, extend asset life, and ensure compliance with codes, standards and established procedures. • Maintain assets and safety controls to avoid over pressure or delivery outage. • Maintain asset information to comply with the standards set out by EGD. • Determine probability and consequence of failure to inform maintenance and repair programs. • Maintain competency levels to ensure work is performed by qualified and competent workers. • Evaluate effectiveness of maintenance and inspection programs to ensure effective risk reduction to the lowest practicable level.
Renew/Retire	• Determine probability and consequence of failure to inform renewal decisions. • Develop proactive renewal programs for assets that are nearing end-of-life (informed by data and tacit knowledge and housed within the Integrity Management System). • Retire assets using a process that meets or exceeds codes and standards.

5.3.2 Stations Inventory

Figure 5.3-3 depicts the typical schema and interconnection of systems associated with stations. Station components and layout will vary based on the design, type, and function of the station. In general, and where applicable for the specific station type, the layout will consist of the inlet supply piping below grade. A typical station consists of the following system components: the inlet valve assembly for isolating and/or bypassing the station, the measurement system to accurately track the gas flow or volume, the heating system, the pressure control system, the odourization system, the outlet/supply valve assembly, and the outlet piping. These systems are interconnected through the telemetry system, which monitors and controls the operation and performance of each station component.

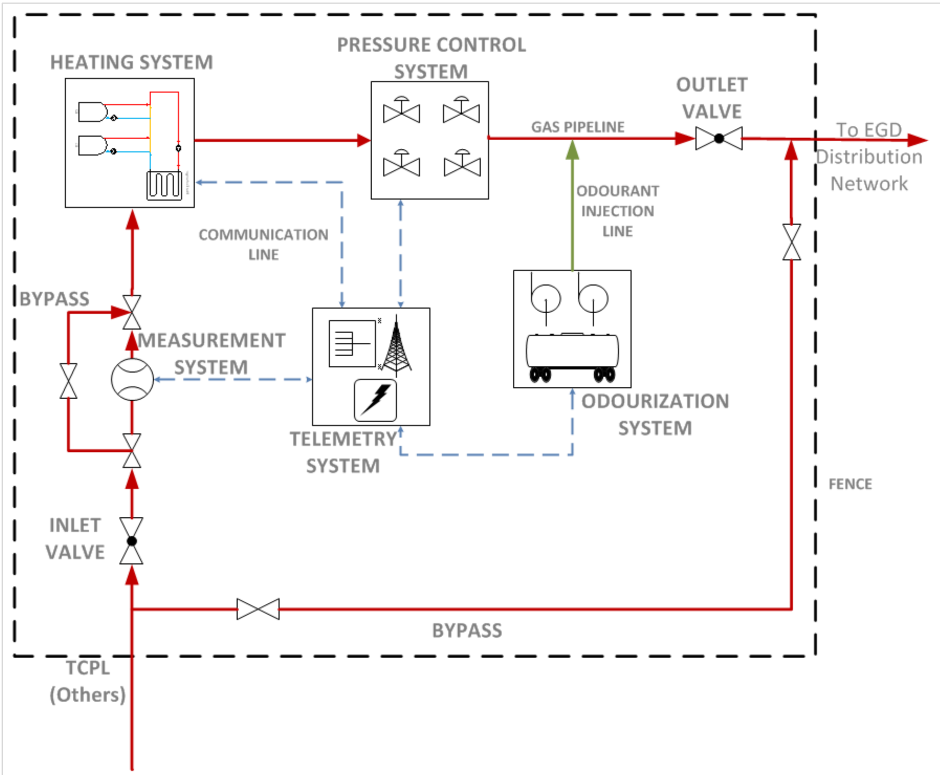


Figure 5.3-3: Station Components

The complete asset inventory for the Stations asset class is presented in **Table 5.3-3.**

Table 5.3-3: Stations Asset Class Inventory

STATIONS	QUANTITY
Gate Stations	**50**
Pressure Control	323
Valves	880
Measurement	89
Heating Systems	
Boilers	108
Exchangers	43
Odourization	179
Telemetry	1019
Feeder Stations	**22**
Pressure Control	112
Valves	176
Measurement	19
Heating Systems	
Boilers	11
Exchangers	6
Telemetry	174
District Stations	**2,163**
Pressure Control	7,975
Valves	2,094
Measurement	7
Heating Systems	
Boilers	20
Exchangers	1
Telemetry	90
Header Stations	**2,704**
Pressure Control	5,928
Valves	1,143
Sales Stations	**11,738**
Pressure Control	27,660
Valves	3,030
Measurement*	-*
Telemetry	32
Civil Assets	
Buildings	226
Land	160 sites 247,000 m^2
Integrity Assets	28

**Inventory count for Sales Station Measurement is captured within the Customer Assets asset class.*

5.3.3 Stations Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Gate Stations	16	Gate and feeder stations are assessed using the same condition criteria. At certain sites, the telemetry, pressure control, and heating system components were found to have the following deficiencies: obsolescence, performance issues, and non-standard configurations.	The risks at gate and feeder stations are: *Safety Risk*: Due to impact on surrounding population in the event of loss of containment *Financial Risk*: Commodity loss, repair costs, and regulatory penalties *CSAT Risk*: GHG emissions, loss of service to customers, and company reputational impact	The maintenance strategy for gate stations is scheduled as described in the Regulation and Measurement (R&M) Manual: • Weekly gate station inspections • 1 operational inspection annually • 1 maintenance inspection annually	EGD has the following strategies for gate and feeder stations: • **Gate & Feeder Station Replacement Program**: Proactive replacement of component groups with the highest probability of failure, non-compliant assets, and the realization of opportunities for multiple component group replacements per station location as required. • **Telemetry Program**: Proactive upgrades of small-scale, obsolete telemetry components. These upgrades will be out of scope for larger-scale station replacement projects. • **Compliance Remediation Program**: Proactive focus on code compliance issues found through detailed site surveys. These will be addressed through a grouped program approach, outside the scope of larger-scale replacement projects.
Feeder Stations	15			The maintenance strategy for feeder stations is scheduled as described in the R&M Manual: • Monthly feeder station inspections • 1 operational inspection annually • 1 maintenance inspection annually	
District Stations	18	Field condition survey assessments identified the existence of boot style regulators, below-ground installations, non-conforming configurations, and vintage/obsolete components, contributing to a higher potential of failures and operational issues.	The risks at district stations are: *Safety Risk*: Employee safety, threat to over pressuring the downstream network *Financial Risk*: Repair and high maintenance costs *CSAT Risk*: Loss of service to customers, reputational impact	The maintenance strategy for district stations is scheduled as described in the R&M Manual: • 1 operational inspection annually • 1 maintenance inspection every five years	EGD has the following strategy for district stations: **District Station Replacement Program:** Proactive replacement program that targets stations based on obsolescence, condition, and age. The program targets approximately 20 stations per year, aligned with historical replacement rates that maintain the average age of the population.
Header Stations	18	Field condition survey assessments of header and sales station sites have found non-conforming configurations and installation locations deemed to be potential hazards to the safe operation of the station site.	The risks at header and sales stations are: *Safety Risk*: Public impact, threat to over-pressuring customer piping *Financial Risk*: Repair and high maintenance costs, customer supply impact *CSAT Risk*: Loss of service to customers, reputational impact	The maintenance strategy for header stations is scheduled as described in the R&M Manual: • 1 operational inspection every five years	EGD has the following strategy for header stations: **Header Station Replacement Program:** Proactive replacement program that targets stations based on obsolescence, condition, and age. The program will target approximately 50 stations per year, which is aligned with historical replacement rates that maintain the average age of the population. Header stations continue to be monitored through the inspection program and condition will be assessed as problems are detected.
Sales Stations	17			The maintenance strategy for sales stations is scheduled as described in the R&M Manual: • 1 operational inspection every five years, or one operational inspection annually (depending on classification)	EGD has the following strategy for sales stations: **Sales Station Replacement Program:** Proactive replacement program that targets stations based on obsolescence, condition, and age. The program will target approximately 100 stations per year, slightly higher than historical values to maintain the current average age of the population. Sales stations continue to be monitored through the inspection program and condition will be assessed as problems are detected.

5.3.4 Gate and Feeder Stations

Gate stations act as a critical pressure control and custody transfer point from the transmission company's pipelines into the EGD distribution network. Feeder stations act as a major pressure control point within the extra high-pressure distribution network.

Figure 5.3-4 and **Figure 5.3-5** represent the age of the various systems at all gate and feeder station sites. Over time, different station components were replaced based on their condition. For gate and feeder stations, the age of individual systems is used for evaluation, rather than the age of the original activation of the station site. Typically, the oldest assets tend to be the valve and pressure control components, which have the longest expected life span.

Based on evaluations and SMA interviews, the expected lifespan for each system is outlined in **Table 5.3-4**. The expected life for these systems is aligned to the current asset population and to the historical replacement strategy.

Table 5.3-4: Life Expectancy for Gate and Feeder Stations

STATION COMPONENT	EXPECTED LIFE (SMA INPUT)*	AVERAGE ASSET AGE (YRS.)	MAX. ASSET AGE (YRS.)	# OLDER THAN EXPECTED LIFE
Pressure Control	37 to 45	16	57	4
Odourization	28	13	23	0
Heating System	18 to 24	12	22	6
Telemetry	14 to 23	13	33	4

** For systems older than expected life, the average of SMA input is used.*

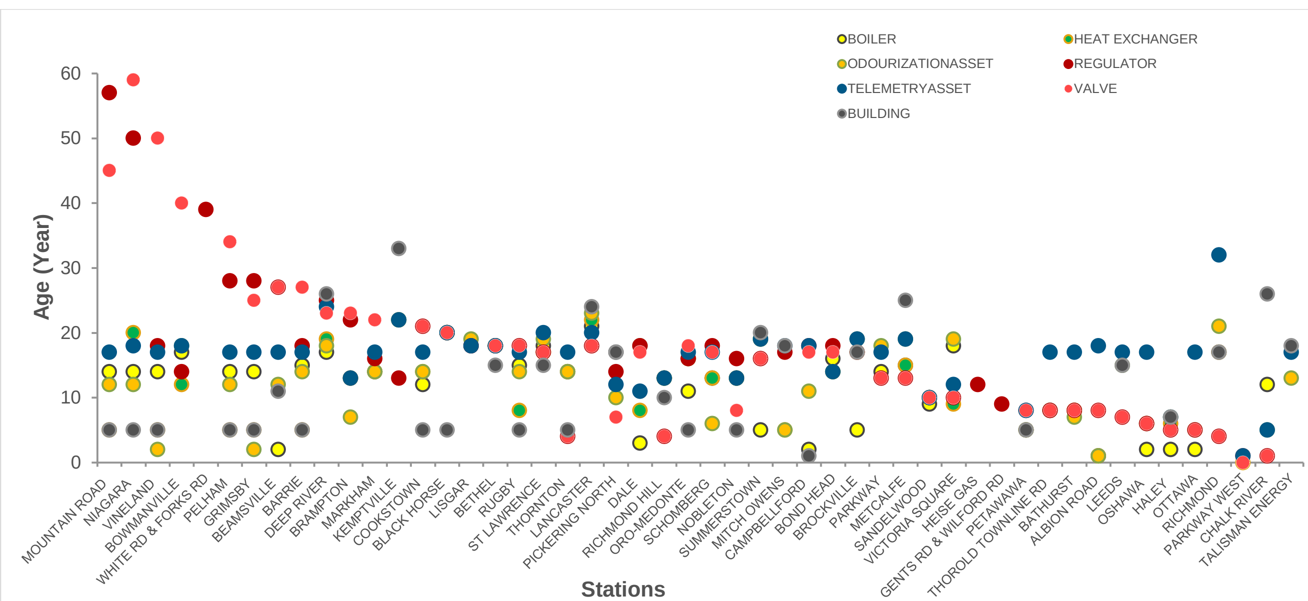


Figure 5.3-4: Gate Station System Age Analysis

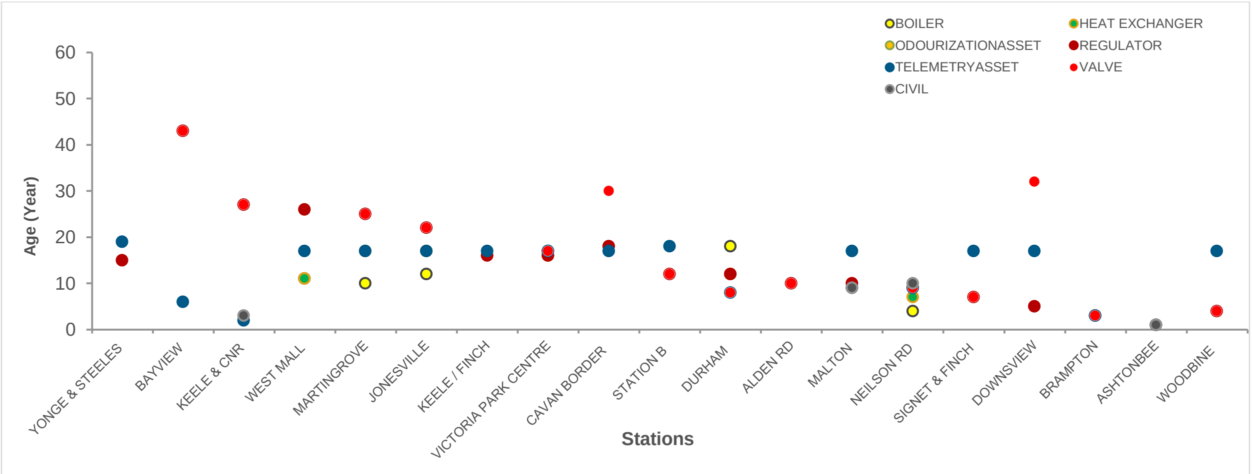


Figure 5.3-5: Feeder Station Age Analysis

5.3.4.1 Condition Methodology

Gate and feeder station components at each site vary in age, based on the replacement history of the site. Based on SMA input and data confirmation, mechanical components and systems within stations have a shorter lifespan than other gas carrying assets, such as linear pipelines, due to mechanical operation and gradual wear. The useful lifespan of station assets vary depending on several site-specific factors such as environment, historical maintenance, and system operating demands. As these systems and components reach the end of their useful life, replacements are planned in advance to mitigate potential failures.

Gate and feeder station assets are inspected and maintained on a regular basis - gate stations are inspected weekly and feeder stations are inspected monthly. Semi-annual operational checks and annual internal component maintenance inspections are also performed. Inspection results and trouble call history are recorded and analyzed to understand asset performance, condition, and health.

The condition and health of gate and feeder station components is evaluated based on the following component attributes:

- The age of critical components, such as regulators, boilers, RTU, etc.
- The performance of the asset, such as known operational problems
- Asset history and the evaluation of failure events
- SMA input

In addition to inspection results, asset age, and performance, field condition surveys are completed to further understand condition details that cannot be determined through data analysis. Field condition surveys evaluate site issues described in **Table 5.3-5**.

Table 5.3-5: Potential Station Issues

ISSUE	DESCRIPTION
Obsolescence	Parts are no longer available; repairs result in long downtime, or repair costs are excessive.
Capacity	The asset is unable to deliver the required demand (i.e., insufficient gas supply, heating requirements, over-working components, etc.), and could result in loss of supply to customers.
Non-standard configuration	Station configurations are not in compliance with current design standards.
Performance issues	The asset requires frequent maintenance calls and adjustments.
Dirt and debris	Dirt and debris increase the probability of failure and downstream over-pressure situations.

ISSUE	DESCRIPTION
Difficulty to operate	Operating difficulties contribute to increased maintenance costs and potential employee safety concerns.
Sealing issues	Sealing issues increase the probability of asset failure and downstream over-pressure situations.
Damaged	Damaged components contribute to increased maintenance costs and potential employee safety concerns.
Inaccessible	Component accessibility issues contribute to increased maintenance costs, potential asset failures, and employee safety concerns.
Poor glycol conditioning	Glycol conditioning issues indicate the degradation of heating system internal components, which result in higher maintenance costs and decreased component reliability.
Communication issues	Communication issues contribute to electronic component failures, loss of remote monitoring, alarming, and control.
Non-standard electrical configurations	Electrical configurations are not in compliance with current design standards and may result in a higher potential for electrical supply failures, employee safety concerns, and violation of ESA standards.
Backup power concerns	Lack of adequate backup power contributes to a high probability of station power loss during hydro outages, resulting in system and monitoring failures.
Leak containment concerns	Leak containment issues contribute to potential code compliance violations and potential high cleanup costs in the event of loss of containment.
Component problems	Recurring component issues contribute to increased failures and component reliability concerns.
Equipment accuracy	Equipment inaccuracy results in incorrect gas measurement systems and potential revenue loss.
Presence of corrosion	Corrosion is an indication of component degradation and less reliable assets.
Damage to insulation/coating	Insulation damage promotes rapid corrosion growth and piping.
Pipe Heaving/Movement	Pipe heaving occurs due to inadequate heating supply or improper construction methods, resulting in undue stress to piping and other components.
Piping & facilities footings & support	Improper support could result in movement or settlement, causing undue stress to the piping and components.
Building issues	Building issues can result in leaks and lack of component protection, causing premature failure and less reliable assets.
Grounds/property concerns	A sinking foundation causes stress in piping and other critical components.
Perimeter security	Damages to fences or other physical security equipment could result in vulnerability threats.

Technicians capture and record station asset conditions based on **Table 5.3-5**, ensuring information collected is accurate, verifiable, and timely.

Aside from condition and health, other factors such as compliance and asset obsolescence contribute to station replacement decisions. Although current design standards conform to current codes, a review process is ongoing to ensure that existing gate and feeder stations conform to all code requirements.

The evaluation of the health and condition of these assets using this methodology provides insight into the expected asset lifespan, as issues are leading indicators of failure and decreased asset reliability. The consequences of these potential failures are described in **Section 5.3.4.3**.

EGD is in the development phase of a Facilities Integrity Management Plan (FIMP), which will ensure that facilities within the gas distribution network are suitable for continued safe, reliable, and environmentally responsible service. The FIMP will provide the framework to identify threats, monitor facility conditions, eliminate or mitigate threats, and manage Integrity data. Included station subclasses are gate, feeder, and storage stations.

The FIMP complies with the most recent requirements of the *TSSA Director's Code Adoption Document*, the *NEB Onshore Pipeline Regulations* and the *CSA Z662* standard. The FIMP is modeled after the Canadian Energy Pipeline Association *FIMP Recommended Practice (RP)* document as referenced in *CSA Z662*.

The FIMP is a continuous improvement program based on Plan-Do-Check-Act principles as defined in *CSA Z662 Annex N*. There are existing initiatives within EGD which enforce routine maintenance and/or visual inspections of assets located within our facilities. The FIMP covers stations and facilities that are not covered in the TIMP and the Distribution System Integrity Program. The purpose of the FIMP is two-fold:

- To create condition monitoring programs for assets which do not have any inspection, maintenance, integrity program in place. This includes buried and above-ground piping, heat exchangers, and odourant tanks.
- To eventually incorporate all inspection and maintenance procedures in place on station assets to comprehensively understand the condition of EGD facilities.

While routine maintenance and visual condition inspections have provided EGD insight on asset condition evaluation within stations, the FIMP will provide direct evidence in the form of quantifiable data on assets to supplement existing condition information. This data will help EGD understand whether certain assets are fit for service or require mitigation, which will inform strategic planning activities, leveraging Integrity results to further refine the scope of the capital plan accordingly.

Over the long term, the initiative will develop a risk-based inspection (RBI) approach to prioritize and identify which assets and facilities are of highest priority or concern to EGD. This kind of analysis requires time to gather asset data (both operational and design parameters) and the use of appropriate software in order to perform necessary calculations as per *API 581 (RBI)*.

Evaluation of Integrity Assets at Large Stations

Integrity mains, managed through the IMP, are a subset of pipeline vital mains operating at stress levels of 30% SMYS and greater, and targeted vital mains that operate at stress levels less than 30% SMYS. The current seven-year inspection cycle for these transmission mains requires in-line inspections, performed by inserting an ILI tool (launchers) at an upstream location (typically at gate stations) and removing the tool from the pipeline at station sites downstream (receivers). Prior to completing these inspection cycles, an evaluation of the supports, foundation, piping, launchers, and receivers is completed to determine if settlement has occurred (causing stress to the integrity assets), and to determine if the assets are in acceptable condition to be fit for service.

5.3.4.2 Condition Findings

Table 5.3-6 summarizes the condition deficiencies found at gate and feeder station sites.

Table 5.3-6: **Evaluation Criteria and Deficiencies for Gate and Feeder Stations**

COMPONENT	EVALUATION OF CONDITION	NUMBER OF STATIONS WITH DEFICIENCIES
Pressure Control	• Obsolescence • Capacity • Non-standard configuration • Performance issues • Presence of dirt/debris	27

COMPONENT	EVALUATION OF CONDITION	NUMBER OF STATIONS WITH DEFICIENCIES
Station Valves	• Difficult to operate • Sealing issues • Damaged • Inaccessible	29
Heating System	• Obsolescence • Capacity • Performance issues • Poor glycol conditioning	24
Telemetry Systems	• Obsolescence • Communication issues • Non-standard electrical configurations • Backup power concerns	58
Odourization System	• Obsolescence • Leak containment concerns • Component problems	23
Measurement System	• Equipment accuracy	20
Piping	• Presence of corrosion • Damage to insulation/coating • Pipe heaving/movement	27
Civil Assets	• Building issues • Grounds/property concerns • Perimeter security • Signage or station protection	37
Integrity Assets	• Improper supports • Operability of facilities for service	11

Table 5.3-6 lists a significant number of deficiencies found in telemetry system components, largely due to obsolescence.

In addition to condition assessments from each site, an examination of the failure history of all asset subclass components is completed. **Figure 5.3-6** and **Figure 5.3-7** illustrate the failure history for each gate and feeder station sub-system between 1999 and 2016. For gate stations, the pressure control, odourization and heating systems have the greatest number of failures. For feeder stations, the telemetry system, heating system and pressure control systems have the greatest number of failures.

This data helps to confirm the condition findings and identified deficiencies and is used for building failure projections and consequence analyses as input into the Risk Assessment process. The condition findings, asset/component age, failure history, and risk calculations are used together for setting project priorities within the Stations asset portfolio.

For example, Barrie Gate has experienced a high number of failure events over the period of 1999 to 2016. The condition assessment for Barrie Gate identified several of the sub-systems that have condition concerns, particularly with the pressure control, heating, and odourization systems. Component age analysis (see **Figure 5.3-4**) indicates that these components are approaching end-of-life.

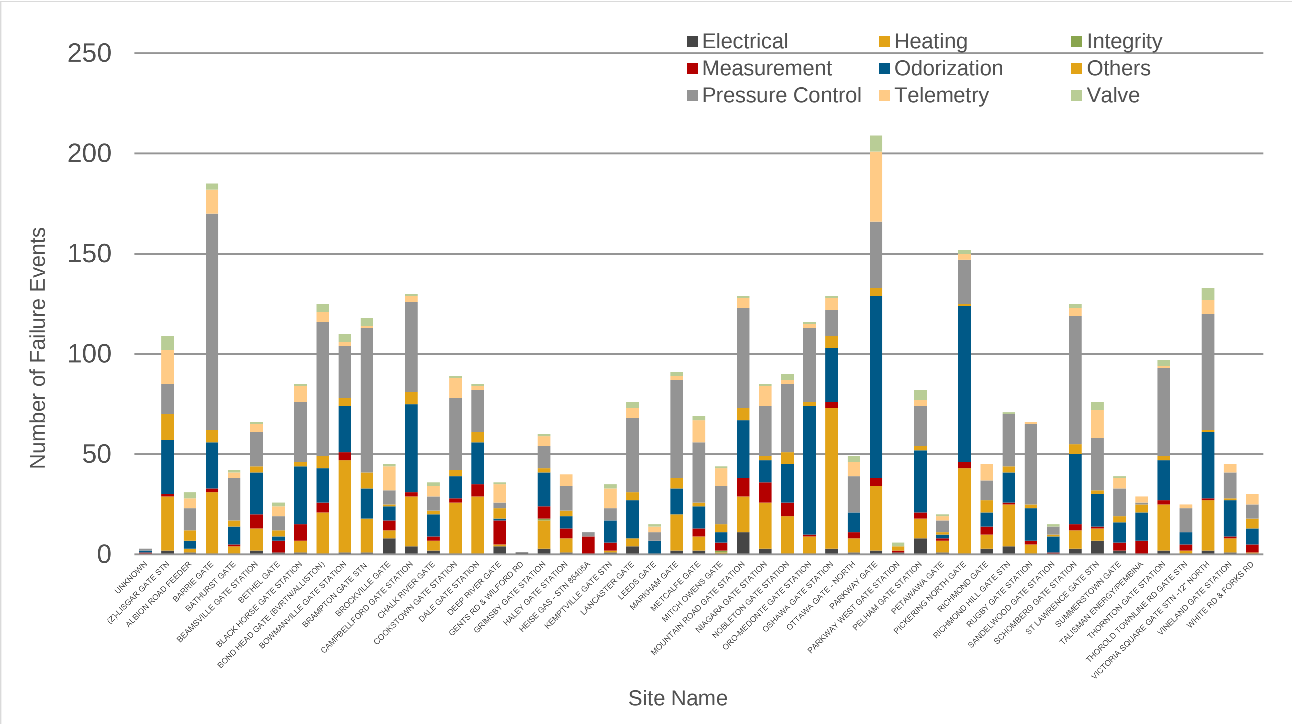


Figure 5.3-6: Gate Stations Historical Failure Data

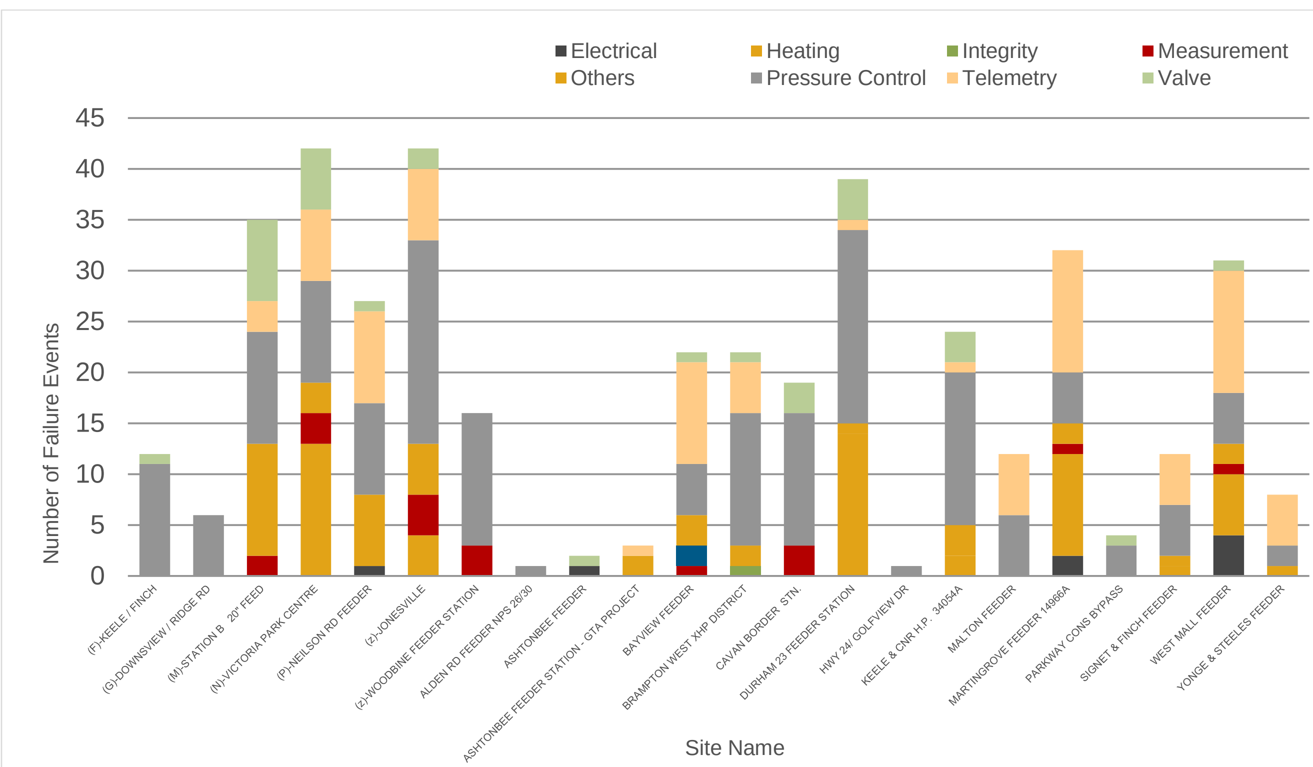


Figure 5.3-7: Feeder Stations Historical Failure Data

5.3.4.3 Risk and Opportunity

Gate and feeder stations are a vital part of the distribution network; as such, complete system failures impacting the safe and reliable distribution of natural gas have significant consequences and must be avoided. Mitigation strategies to reduce risk to the lowest practicable level include redundancy of critical systems, multiple layers of protection, and a comprehensive inspection and maintenance program.

The following are consequences associated with failure to maintain gate and feed station components:

- Failure of the pressure control system, resulting in over- or under-pressure, or capacity growth issues
- Failure of the measurement system
- Failure of the valve system
- Failure of the telemetry system
- Loss of power supply
- Failure of the heating system
- Failure of the odourization system
- Issues due compliance-related non-conformances

The sub-systems within gate and feeder stations have interdependencies which may impact the reliability and performance of other systems. Therefore, the complexity of failures in one sub-system may lead to potential failures of other sub-systems. For example, the measurement system is used to both measure gas flow and calculate the proper odourant injection rate.

Regulators are a mechanical component in the pressure control system that are inspected, tested, maintained, and repaired on an ongoing basis through a rigorous maintenance and inspection program to ensure they perform as needed. Due to the critical function of the regulator to maintain pressure control, pressure control design standards require a redundant run as a backup in the event of a failure. The impact and frequency of a pressure control failure varies - the frequency of a pressure control failure causing a minor impact, such as a repair, is higher than the frequency of over-pressure delivery to a customer. This is due to the multiple layers of protection within the gas distribution network. Parts are repaired or replaced as needed to minimize the likelihood of full pressure control system failure. EGD monitors the real-time performance of regulators' pressure control components through SCADA alarms overseen by the Gas Control group.

The odourization system is comprised of the following components: injection pumps, flow meters, pneumatic valves, and relief valves. These are repairable parts, which experience higher failure rates with higher usage over a short period of time. Parts are repaired or replaced as needed. Repairs resulting in long-term supply loss of odourant will result in unodourized gas going into the distribution system, odourant being the last line of defense in notification of a pipeline leak. Some legacy odourant systems do not provide adequate protection in terms of containment of leak events. This can result in substantial cleanup costs and effort, contamination, and reputational impact. The odourization system has two main failure modes: failure to maintain odourant level and identification of an odourant leak. Failure to maintain odourant level could mean under-odourizing or over-odourizing the gas. The frequency of under-odourization is higher than over-odourization or an odourant leak.

The heating system's main sub-components are the heat exchanger and the boiler system. The boiler system is comprised of repairable parts experiencing higher failure rates with higher usage over a short period of time. A heating system failure could result in compromising the performance of other station sub-systems or have implications outside station property.

The telemetry system is comprised of components with varying expected life. Some assets (such as generators) have an expected life as short as 14 years. In other cases, such as RTUs, the useful life is limited by the obsolescence of the component. Sensors and other components can also experience early-life failures as a result of harsh operating environments. Telemetry components are checked weekly as part of gate and feeder station inspections. The telemetry system can be infiltrated by cybersecurity attacks through its communications network. Consequences of a cybersecurity attack could result in not only a telemetry system loss on-site, but could also bring down the entire communications network to all station and network monitoring sites.

Station risks are identified through field surveys and the identification of sites with component-specific issues and compliance-related non-conformances. Issues and concerns are compared against asset attributes such as age and historical component-specific failures. The probability of failure for an asset subclass component is generated using failure history and the age of the asset, considered along with the QRA to develop project priorities.

The following failure scenarios were identified for gate and feeder stations:

- **Pressure Control**: Pressure control failures could cause the unplanned release of natural gas, a pipeline rupture, or over-pressure delivery to customers. Each of these could result in a release of natural gas to the environment, ignition, or a potential explosion. The financial impact includes commodity loss, service disruptions, increased network leak surveys and system checks, repairs or replacement of EGD-owned property, or damages caused to public, commercial, or industrial property. In addition, pressure control failures may lead to unintended emissions of natural gas to the environment, impact EGD's reputation, and fail to meet the expected high levels of operational reliability.

- **Loss of Measurement System function**: Measurement equipment at gate and feeder stations is used to accurately inject odourant into the pipeline. Loss of measurement functionality could lead to improper odourant levels and undetectable gas leaks, inaccuracy of gas measurement, and inaccurate billings of commodity transfer from the transmission company to EGD. Inaccurate measurement systems could result in volume purchase disputes.
- **Loss of Odourant System function**: The odourant system adds the odor in natural gas so that it is detectable in the event of a leak. Failure of the odourant injection system could result in leaks not being readily detectable. A threat potential also exists if adequate containment is not in place, as well as financial consequences due to potential liabilities of not maintaining proper odourant levels within the gas stream, which could include service disruption implications, commodity losses from undetected leaks, public property damages, or fines from the technical regulatory authority. Reputational and financial risk may result from the reduction in emergency and unplanned callouts to unreliable odourant injection systems. Inoperable odourant systems would lead to a failure to maintain proper odourant levels as mandated by code requirements, potentially impacting EGD's reputation for operating a safe and reliable gas distribution network.
- **Loss of Heating System function**: Loss of the heating system function could result in freezing of components within the station, resulting in loss of pressure control and potentially leading to an over-pressure or under-pressure situation. The financial impact includes commodity loss, service disruptions, increased network leak surveys and system checks, repairs or replacement of company-owned property, or damages caused to public, commercial or industrial property. Inoperable systems will lead to a failure to maintain operational supply to customers, and will impact EGD's reputation.
- **Valve System malfunction**: The frequency of a valve malfunction is low, however, inoperable valves within stations pose the risk of inability to isolate gas flow within the station, leading to increased maintenance and the potential for commodity loss, as well as impacting the confidence of customers and EGD's reputation.
- **Loss of Telemetry System function**: Failure of real-time monitoring would cause a delay in responding to system operation problems or emergencies. Stations with an older telemetry system have a higher failure frequency. Without the telemetry system, there is no visibility to the performance and operation of EGD's system, causing increased callouts, emergency system repairs, and greater patrols. Lack of visibility to EGD's network will impact consumer confidence and EGD's reputation. Failures of the telemetry system could also be caused by cybersecurity attacks into the communications network.
- **Loss of Electrical System function**: The odourant, telemetry and heating systems all rely on electrical power or backup power systems to function properly. Without a power supply, system gas is unodourized, eliminating the last line of defense. Monitoring of system performance will be lost. Gas temperatures will decrease, potentially damaging equipment and external civil assets. Lack of reliable electrical power will cause increased callouts and emergency power supply mobilizing. Inoperable systems lead to failure in supplying gas to EGD customers and will impact company reputation. The frequency of losing power at a station depends on the frequency of electricity outages in the area, third-party damage, and backup power system failures.

Gate or feeder station failures can occur in any of the seven major asset subclass components. The impact of each system failure is different; however, there are some interdependencies between system failures. The extent of impact is dependent on the gate and feeder station location (i.e., whether the station is in a populated or remote area), the number of customers serviced by the gate or feeder station, and whether the gate and feeder station is a single-feed or multi-feed system.

The risks at a gate or feeder station is dominated by financial risk, which may require fixing any damages to public property, relights due to service disruption, commodity loss, replacing and repairing company property, and any regulatory penalties. The customer satisfaction risks for gate and feeder station failures could impact gas supply to EGD's customers, leading to operational reliability and reputational impact. The health and safety risk for gate and feeder sites are higher if the station is located in an urban or developed area due to a high potential impact on the surrounding population.

The condition at each gate and feeder station is unique (in terms of asset condition, obsolescence, and compliance), requiring detailed QRAs for all stations.

5.3.4.4 Strategy

Gate and Feeder Station Replacement Strategy

The gate and feeder stations replacement strategy involves the replacement and/or rebuild of station components at sites with the highest expected failure rates and deficiencies identified through site inspections and condition monitoring. Gate and feeder station initiatives are prioritized based on a complete understanding of asset health, risk assessment results, and compliance/design standards. The goal of this strategy is to proactively replace or rebuild station components prior to end-of-life to mitigate risks and maintain safe and reliable service to customers. However, there will be instances where reactive replacement is necessary.

Implementation of this strategy may vary by site. Initiatives include:

- Replacement of individual component assets as they fail. For example, a failure of one of the pumps within the boiler system results in the pump being replaced (reactive).
- Replacement of components based on expected failure. For example, if the entire boiler system is in poor condition with a high expectation of system failure, the entire system is replaced (proactive).
- Multiple component rebuilds to benefit from combined resources and project scope. For example, if the boiler system group is in poor condition with a high expectation of failure, and the telemetry and odourization systems are currently approaching poor condition, all three systems are replaced (proactive).
- Replacement and upgrade of components evaluated to be at or approaching capacity, based on projected forecast demands. For example, if regulators are evaluated to be approaching capacity in the upcoming year, its components will be upsized to handle the appropriate projected system demands (proactive).

EGD continually monitors asset performance and refines its analytical models based on best available data (including refining the capture of condition information, structured failure data analysis, data quality improvements, and ongoing improvement of projection models). As the quality of models and data using the Plan-Do-Check-Act approach continues to improve, EGD will be better able to predict asset condition, support the longer term replacement plan and modify the replacement strategy accordingly.

Compliance Remediation Strategy

The goal of the Compliance Remediation Strategy is to eliminate deficiencies and compliance issues at gate and feeder stations. These deficiencies have been identified through Engineering Assessments and Process Hazard Analysis evaluations done on a sample set of stations. Compliance concerns are categorized in key sections of the following publications:

- EGD Standard for Grounding Methods
- Ontario Building Codes and Ontario Fire Codes
- Ministry of the Environment and Climate Change (MOECC) Environmental Compliance
- Security of critical facilities and gate stations for EGD (as identified by Corporate Security) Electrical Compliance and Back Up Generators Applicable Codes: Canadian Electrical Code and Ontario Amendments

The Stations Measurement and Regulation Compliance strategy will be a managed approach to monitor and address identified code compliance issues found through detailed site surveys and the upgrades required to meet code changes impacting current configurations. The Compliance Remediation Strategy will target individual station sites found to have minor compliance deficiency issues such as access/egress issues, building code and fire code issues, venting issues, environmental compliance approvals, and site security vulnerability issues.

Telemetry Strategy

Telemetry components collect and send crucial system operational data to the SCADA system, monitored by the Gas Control group to manage system performance and operation. Real-time monitoring allows EGD to respond to operational issues and emergencies and have visibility and control into the performance and operation of the gas distribution system.

Telemetry components have varying life expectancies and are upgraded to address obsolescence, communication issues, non-standard electrical configurations, and backup power. Obsolete equipment cannot be replaced like-for-like if it is damaged and may compound communication issues. Based on condition findings, numerous deficiencies have been identified.

The telemetry strategy strives to maintain acceptable telemetry equipment performance to ensure that evolving technologies can be utilized. It will focus on component replacements not included with the larger gate and feeder station projects, as these components have a much shorter anticipated life span. The scope of the Telemetry strategy includes:

- Replacement and upgrade of telemetry instrumentation assets
- Replacement and upgrade of telemetry electrical and power generation assets
- Replacement and upgrade of telemetry communication assets
- Replacement and upgrade of servers and network devices such as firewalls, modems, routers, etc.
- Supply and installation of security assets (swipe card access, video surveillance, and intrusion detection assets)
- Tower network expansion where required to enhance communication pathways
- Computer terminal and server expansion to support central logbook repository, data analytics and data historians
- Continued development of the maintenance layer at major stations and the implementation of capabilities to backhaul data from remote sites to enable video surveillance, swipe card access at all compounds and buildings, and a central logbook repository for all sites

Integrity Retrofit Strategy for Pipelines >30% SMYS

The Stations Integrity Retrofit Program will focus on pipelines with >30% SMYS and existing launcher and receiver components within station compounds. Launchers and receivers are used to accommodate pipeline analysis tools travelling in and out of the pipeline. The program will examine the adequacy of existing components and facilities used within the ILI program, and remediation of deficiencies found.

The program will evaluate every station site where components exist for launching and receiving pipeline assessment tools for the following issues: improper supports, improper foundation, non-standard tubing configurations, and the identification of any locations which do not have permanent facilities installed. These issues will be addressed through the program to remediate all issues found affecting the pipeline and its component supports, assess component condition, and install permanent assets used within the Integrity Program (if temporary assets were used).

5.3.5 District, Header, and Sales Stations

District, header, and sales station assets reduce pressure within the gas distribution network and regulate the flow of gas from a higher pressure (up to XHP 4,500 kPa) to a lower pressure depending on the needs of downstream customers. These types of stations are typically located above-ground on private property, with or without an enclosure. District, header, and sales stations differ in size, operating pressure conditions, number of downstream customers, and gas volume delivered (see **Table 5.3-7**).

Table 5.3-7: Inlet and Outlet Pressures at District, Header, and Sales Stations

	INLET PRESSURE			OUTLET PRESSURE			
STATION TYPE	XHP	HP	IP	XHP	HP	IP	LP
District Station	X	X	X	X	X	X	X
Header Station		X	X			X	X
Sales Station	X	X	X			X	X

The primary assets for district, header, and sales stations include pressure control components, station valves, and piping (described in **Section 5.3.2**). District, header, and sales stations consist of mechanical components with shorter lifespans relative to other gas carrying assets (see **Table 5.3-8**). This is broadly aligned with preliminary models predicting the useful life of regulators and the life expectancy of these small station assets based on SMA experience.

Table 5.3-8: Estimated Life Expectancy for District, Header, and Sales Stations

STATION TYPE	EXPECTED LIFE (SMA INPUT)	AVERAGE ASSET AGE (YRS.)	MAX. ASSET AGE (YRS.)	NUMBER OF SITES OLDER THAN EXPECTED LIFE*
District Stations	27 to 37	18	51	152
Header Stations	31 to 40	18	51	12
Sales Stations	25 to 38	17	59	1646

** For systems older than expected life, the average of SMA input is used.*

Although age is not the only factor in evaluating station asset conditions, an increase in failure is seen as the asset approaches the end of its useful life.

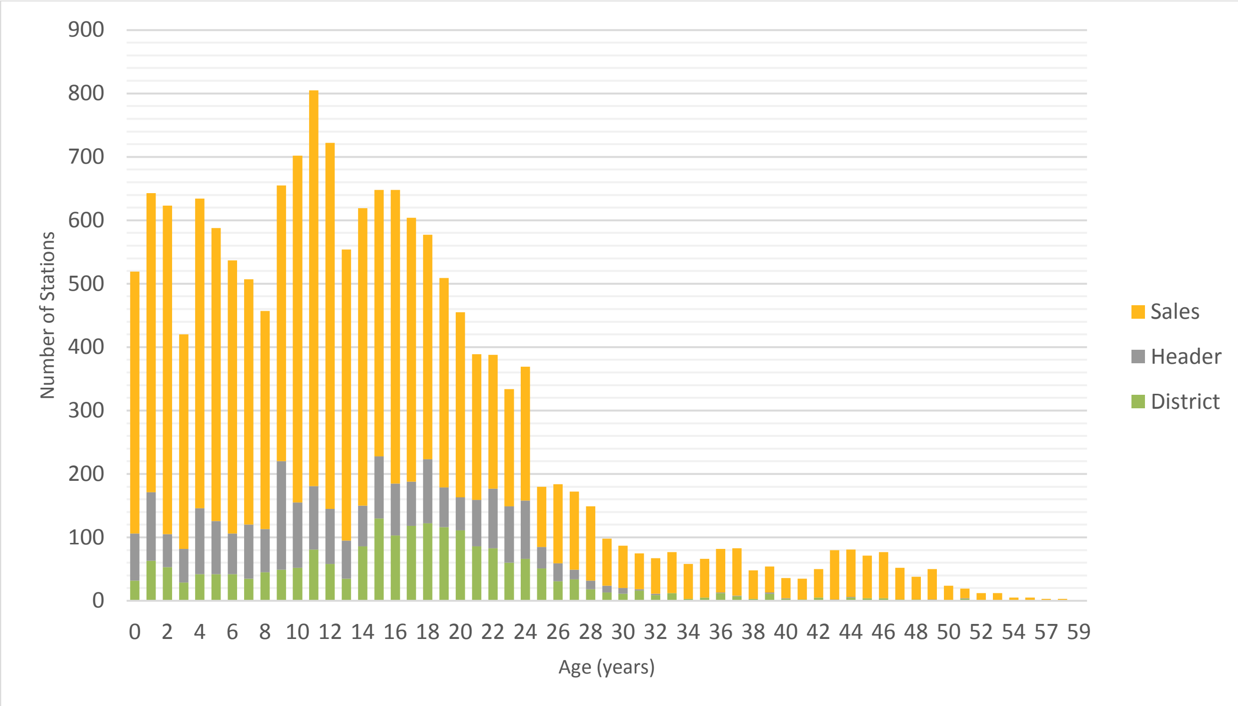


Figure 5.3-8: Population Demographics - Small Stations

District Stations assets undergo an annual operational inspection to ensure the ongoing reliability and integrity of its components. The inspection cycle also includes a more detailed internal component inspection every five years. If the asset fails the annual operational inspection, maintenance is performed to restore the asset. Results of the inspections are recorded and analyzed to understand asset condition.

District stations are generally installed either above-ground or below-ground in a vault (see **Figure 5.3-9**). Above-ground, they may be protected from the elements within a box enclosure or exposed to the elements. Below-ground vault locations can experience aggressive condition degradation from a wet environment, flooding, sidewalk, road runoff, and can cause confined space safety concerns. These assets can experience pipe coating degradation, which can lead to corrosion, impacting the mechanical operation of the pressure control and valve systems.

Figure 5.3-9: Examples of District Stations

District stations that experience a high differential pressure reduction from inlet to outlet pressure may be exposed to a higher risk of failure. For instance, as natural gas passes through the pressure control device, the gas temperature decreases approximately 4°C for each 700 kPa of pressure reduction (the Joule-Thomson Effect). High differential pressure control will cause significant decreases in gas temperature (from high inlet pressure XHP to lower outlet pressure IP/LP). This drastic temperature reduction can freeze station components, which may cause a loss of pressure control, heaving of the station piping, impacting the surrounding grounds, and damaging roads. The effects of the Joule-Thomson Effect are illustrated in **Figure 5.3-10**. Ice build-up is visible on the downstream components and the station assembly is misaligned due to heaving.

Figure 5.3-10: The Joule-Thomson Effect on a District Station

Header Stations are similar to district stations. Header station assets undergo an annual operational inspection to ensure ongoing component reliability and integrity. The inspection cycle also includes a more detailed internal component inspection every five years. If the asset fails the annual operational inspection, maintenance is performed to restore the asset. Results of the inspections are recorded and analyzed to understand asset condition.

Header stations are generally installed above-ground, usually on private property or easements. They are exposed to the elements and can experience degradation of pipe coatings from exposure to road salt, leading to corrosion. Natural elements can also impact the mechanical operation of the regulators.

Sales Stations assets are inspected every five years for operational performance checks. Inspection frequencies may be increased as required at specific sites. Sales stations (see **Figure 5.3-11**) are generally installed above-ground, on customer property, usually close to the building where the gas supply line enters the customer building. They are exposed to the elements and can experience degradation of pipe coatings from exposure to road salt or other corrosives, which can lead to corrosion. Natural elements can also impact the mechanical operation of the regulators.

Sales station sites are known to have non-conforming configurations and potentially hazardous locations due to clearance issues and potential threats from third-party damage. It is expected that these potential hazards exist across the sales station population of certain vintages, when construction practices were different than today’s standards. It is also expected in some cases that local area development have encroached on the facilities over time.

Figure 5.3-11: An example of a Sales Station

5.3.5.1 Condition Methodology

The methodology for determining the condition of small stations assets uses a combination of empirical analysis of the failure and event history for the asset and a qualitative on-site condition assessment. These methods provide a clear understanding of the station asset age, past performance, future projected reliability, and allow for refinement of reliability modeling based on condition findings, which in turn inform the required replacement rate. The empirical analysis through the Asset Health Review process performs an analysis which helps to make predictions about the life of all assets in the population.

The evaluation of performance and the probability of failure include an examination of the history of performance for pressure control, valves, and piping components. Regular inspection and maintenance practices are conducted to confirm the proper operation of all station components. The results of these inspections, as well as any additional call-outs (trouble calls) are classified into problem/event categories to understand failure modes and to assess trends. Based on Failure Mode and Effects Analysis (FMEA), it was determined that different sub-component groups can fail with different failure modes. The main failure modes for regulators are failure to lock up and leak events. The main failure mode for valves is the failure to operate and leak events. The empirical analysis through the Asset Health Review process is used to make predictions about the life of all assets in the population.

In addition to the scheduled performance inspections, field condition surveys are conducted on a regular basis, to assess, classify, and further understand condition details that cannot be determined through data analysis alone. These field condition surveys include an evaluation of the following:

- Level of corrosion
- Condition of paint and pipe coating
- Performance of the components
- Level of heaving or piping alignment
- Overall site safety condition

Station condition is captured by technicians on site using the FAST software application developed in-house to record asset condition.

Table 5.3-9 outlines the specific condition evaluation criteria used to assess station sub-asset components. The evaluation informs the program risk assessments that validate station priority for station rebuild programs.

Table 5.3-9: Evaluation Criteria for Station Sub-asset Components

STATION ASSET SUBCLASS	CONDITION EVALUATION
Pressure Control	• Operating parameters for each regulator are correct (i.e., outlet pressure matches the correct set point) • Ability to lock up under zero flow condition • Responds appropriately to changes in outlet pressures and flows • Over-pressure protection device operates at its specified set point, and capacity is adequate for its intended use • Obsolete equipment and/or parts not available • Improper/non-standard configuration
Station Valves	• Difficult to operate/move freely • Leak to atmosphere • Damaged or inaccessible • Will not seal • Site-specific condition has changed since install and cannot be operated
Piping	• Presence of corrosion indicators • Damage to insulation or coating • Pipe heaving or movement • Signage or station protection

Other factors to be assessed include:

- Station capacity issues (to ensure the reliability of supply to EGD's growing customer base)
- Compliance-related issues impacting safety and the ability to perform maintenance inspections
- Obsolete equipment no longer supported by product manufacturers
- Compliance with codes and standards

Once failure modes were established, as identified above, historical events were filtered and plotted over time, creating a list of approximately 16,000 failure events from 1999 to 2016. These were analyzed for use in reliability modeling of small stations in the Asset Health Review.

The Asset Health Review uses widely-accepted and applied statistical principles that correlate the age (or usage) of an asset versus failures to produce a model to project future failures. This technique, commonly known as reliability engineering, is the probability that a component or system will perform its intended function under defined operating conditions for a specific period of time. The reliability of an asset or system is determined by applying a statistical method to correlate age of the asset with failures using reliability software tools.

These tools perform recurrent data analyses for repairable assets which help make predictions about the life of all assets in the population by fitting a statistical distribution or function to the data from a representative sample of the population. For repairable assets, the function for the data set can then be used to estimate important life characteristics of the asset such as reliability, conditional probability or intensity of failure at a specific time, its mean life, and failure rate.

The empirical analysis of small stations is further refined on an individual site basis by integrating findings from field condition surveys collected over time. As more assessments are completed, the empirical model is refined. The calculated reliability for individual sites will be adjusted to reflect assets that are in worse condition than anticipated by the reliability models. **Figure 5.3-12** provides a visual representation of how evaluation from the field condition assessment is applied to adjust the reliability for the individual site.

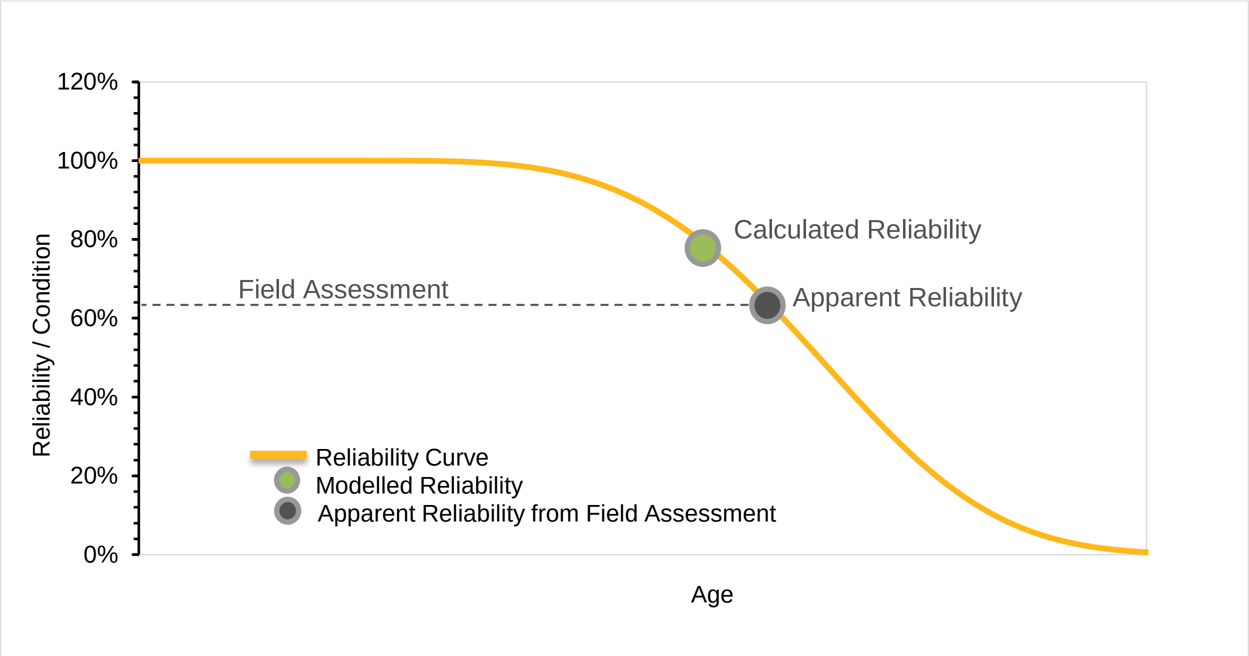


Figure 5.3-12: Station Reliability and Condition Assessment

Based on the findings, station locations identified as having lesser apparent reliability (condition) than the calculated reliability receive increased priority in the Stations Rebuild program. If the apparent reliability is found to be harsher than the calculated reliability based on in-field condition assessments, an adjustment will be made in the calibration of the empirical curves. This adjustment in reliability calculation will result in a difference in the failure projection events calculated above.

5.3.5.2 Condition Findings

As assets age and degrade, they typically begin to fail at an increasing rate and the accumulation of those failures over time will begin to account for a greater proportion of the total population. Using historical failure event rates to model the projected failure events, **Figure 5.3-13** helps to illustrate this relationship over time and provides useful insight into the impact of projected future failure events on the asset population with the current replacement program applied.

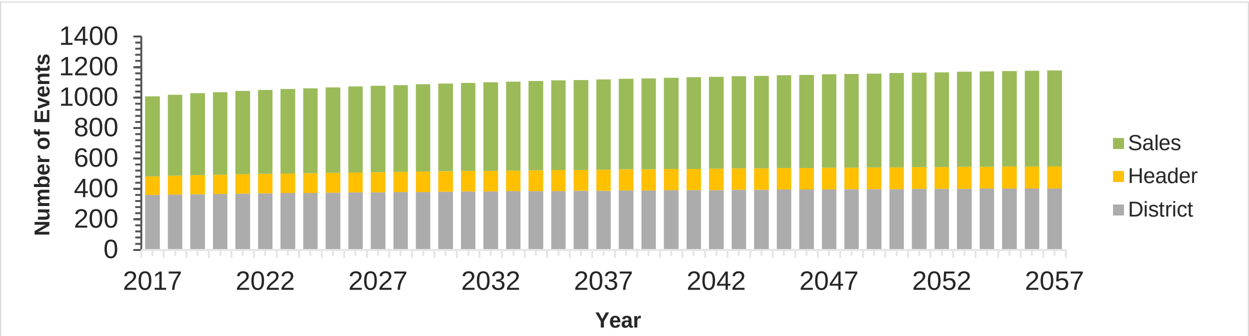
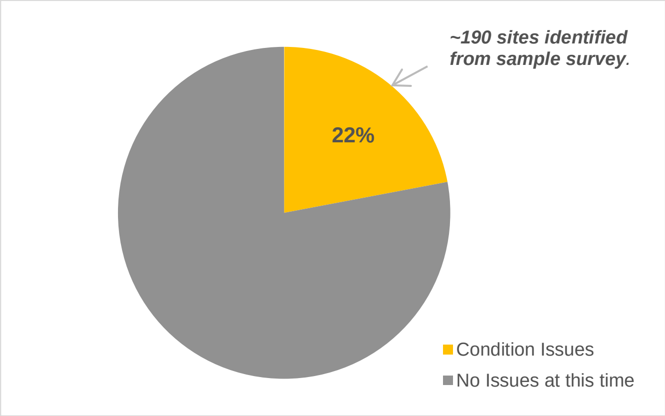


Figure 5.3-13: Projected Regulator and Valves Failure Events - Small Stations

Figure 5.3-13 reveals that header and district station types have a relatively constant and low growth rate in failure events over the next 60 years under the historical and current replacement and renewal programs. It can also be seen than sales stations have a slightly higher growth in failure events with the current replacement pace.

Based on current field assessment results, **Figure 5.3-14**, **Figure 5.3-15**, and **Figure 5.3-16** proportionally reflect the stations with identified pressure control, valve, and piping issues from the surveyed population.



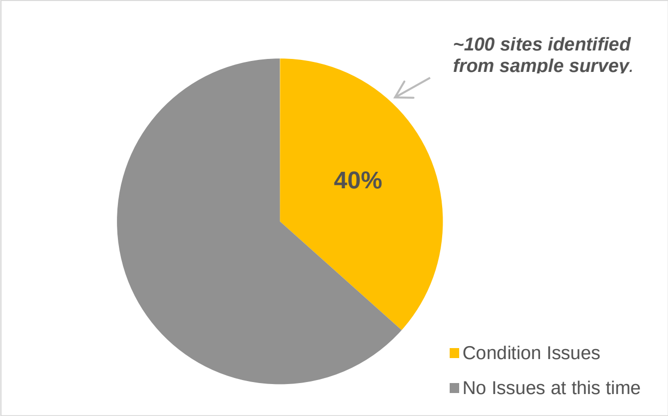


Figure 5.3-14:Surveyed District Station Results

Figure 5.3-15: Surveyed Header Station Results

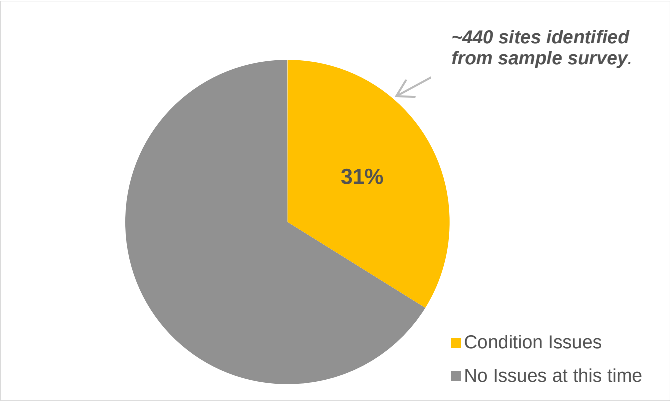


Figure 5.3-16: Surveyed Sales Stations Results

Field condition surveys continue to be collected on an ongoing basis to thoroughly understand the condition of station assets. Results of the surveys obtained to date, where issues have been identified within the valve, pressure control, or piping component groups, has been summarized in the proportional charts above. For example, in the district station population, 22% of sites surveyed have issues found, equating to 190 out of 864 sites surveyed to date. By projecting this rate to the entire population, EGD is expecting to find approximately 470 sites with issues across the entire population. The condition issues found within each of the component groups could be one or several of the condition evaluation criteria identified in **Table 5.3-9**. The issues found are actively addressed through reactive repairs or through replacement programs where appropriate.

Some types of regulator models influence the need to address specific regulator components within the District Station Program. For example, boot-style regulators which use a combination of a flexible “boot” element and gas pressure to regulate downstream flow and pressure may be more susceptible to higher failure rates due to their design. This type of regulator station design has demonstrated susceptibility to failures caused by debris, particulates, hydrates, and sulfur deposits.

Adopting a new design philosophy to use alternative models minimizes the potential for downstream over-pressure.

Figure 5.3-17 illustrates the projected mean cumulative failure rate of boot-style regulators compared to non-boot style regulators, based on failure history analysis. The failure rate of boot style regulators is five times greater than non-boot style regulators, across all ages.

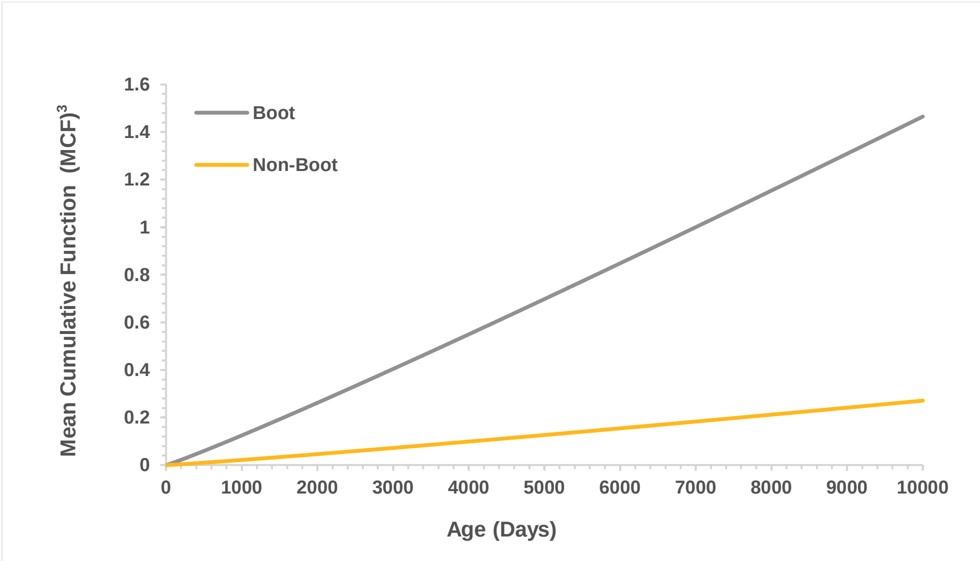


Figure 5.3-17: Failure Rates for Boot and Non-boot Regulators

Field reviews of existing header station sites have found non-conforming configurations or locations deemed to be potential hazards to the safe operation of the station site, such as clearance issues or potential threats from third-party damage. It is anticipated that these potential hazards may exist across the header station population of certain vintages, when construction practices and standards were not consistently applied. It is also expected in some cases that local area development over time has encroached on the facilities resulting in higher risk of station damage from external influences such as vehicle traffic or debris from above or compromised station supports.

5.3.5.3 Risk and Opportunity

Risk

Field condition assessments are reviewed against the risk factors in the appropriate station program. Below is an outline of the hazards identified for each program:

District Stations

- Over-pressure on double boot-style regulators
- Station operating over designed capacity due to system growth
- Failures occurring on obsolete regulators
- Stations installed in below-ground boxes
- Station experiencing loss of containment (leaks)

Header Stations

- Over-pressure on non-boot style regulators
- Failures occurring on obsolete regulators
- Non-conforming station configurations
- Stations with compliance-related issues

Sales Stations

- Over-pressure of non-boot style regulators
- Non-conforming station configurations
- Stations with compliance related issues
- Stations experiencing loss of containment (leaks)

The risk assessment on the following conditions will determine the potential failure of the asset: pressure control, valve system malfunction and loss of containment (leaks). The impact of each of these failures on safety, financial, and customer satisfaction is discussed further below.

Pressure Control: Pressure control failures could cause the unplanned release of natural gas, a pipeline rupture, or over-pressure delivery to customers. The impact and frequency of a pressure control failure varies - the frequency of a pressure control failure causing a minor impact, such as a repair, is higher than the frequency of over-pressure delivery to a customer due to the multiple layers of protection within the gas distribution network.

The frequency of pressure control failure is dependent on the configuration of the station. The frequency of pressure control failure for a station with a single regulator and single run is higher than a station with double regulators and double runs. Each of these could result in a release to the environment, leading to potential ignition or explosions. District and header stations feeding Low Pressure (LP) networks have additional safety consequences, as downstream customers do not have an on-premises regulator. The financial impact includes commodity loss, service disruptions, increased network leak surveys and system checks, repairs or replacement of company-owned property, or damages to public, commercial, or industrial property. Pressure control failures may lead to unintended GHG emissions of natural gas to the environment, impact EGD's reputation and fail to meet the expected high levels of operational reliability.

Valve System Malfunction: The frequency of a valve malfunction is low. However, inoperable station valves pose the risk of inability to isolate gas flow within the station. This would lead to increased maintenance and the potential for commodity loss. Not maintaining operable valves within stations would sway the confidence of customers and impact EGD's reputation.

Loss of Containment (Leaks): The risk of a leak leading to a fire or explosion has the potential to cause injury to members of the public. Risk of an over-pressure event at the station could similarly lead to a leak in the downstream system, including inside the customer's premises if other safeguards fail. Financial loss is possible due to total repair costs, commodity loss, relighting customer gas appliances, and any property damages caused by a gas leak. Risks identified are potential GHG emissions, environmental impact, service interruptions, over- or under-pressure events, and reputational damages associated with reduced public confidence.

District Stations are the delineation between different operating network pressures. Failure causing over-pressure situations result in the upstream higher pressure network (XHP/HP) interacting with the downstream lower pressure network (IP/LP). In this scenario, the pressure of the downstream network increases to levels beyond which it is rated. Over-pressure could lead to failure of the components in the downstream network, over-stressing pipe or fittings, loss of containment, and pressure gas entering customer premises if the customer regulator fails. The potential for fire or explosion is increased in an over-pressure situation. Based on failure data, the frequency of a leak at a station is very low compared to other events.

Boot-style regulators were evaluated through the Asset Health Review to determine failure projection rates for this regulator type. Many of these arrangements are installed in the distribution system. The over-pressure protection for a double boot-style station is provided by placing two boot-style regulators in series where one is the operating regulator and the other monitor regulator. This arrangement has the same failure mode for both the operating and monitoring regulators. If there is a failure in the operator, there may be a similar failure mode in the monitor regulator.

The over-pressure of an LP network may have higher consequences. LP networks are designed such that customers do not have individual regulators at their meter sets. These would normally be considered a second line of defense against potential over-pressure of the piping inside the customer's house.

Under-pressure at a district station can lead to loss of service for customers. This is of particular concern for industrial customers, who expect a reliable natural gas supply for processes, as well as for customer heating needs during colder periods.

Stations approaching design capacity could result in under-pressure situations, loss of service to customers, and station equipment performing beyond recommended operating limits.

Failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.

District stations that are installed below-grade in a vault were evaluated to consider risks such as additional maintenance requirements, increased rebuild cost, and potential for worker injury. It is expected that the projected reliability for these below-ground assets will be lower and will degrade faster than other above-ground assets.

Header Stations are the pressure control point when a distribution main enters private property. Failure causing over-pressure could unintentionally introduce high pressure gas into the customers' property. Leak or loss of containment at a header station can lead to an explosion or fire. However, due to their typical locations, the likelihood of consequential damages is relatively minimal. Some factors included in this risk category are property damage, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a header station can lead to over-pressure in the downstream system, causing potential leaks in the downstream system or inside the customer property if there is an additional failure of the customer regulator. An over-pressure situation increases the potential for a fire or an explosion. Under-pressure at a header station can lead to loss of service for customers, particularly a problem if the gas is used for process or home heating.

Additional issues that were considered in the risk assessments were obsolete regulators, single-run stations, and stations with non-compliance issues. When obsolete regulators fail, they cannot be easily replaced as the existing station configuration may not be suitable for replacement parts. When this occurs, the station must be replaced in its entirety, leading to a disruption in service and gas delivery impact. Single-run stations are stations without a standby run available. A standby run can take over control to provide the required capacity and pressure of gas to a system in the event that maintenance of the station is required. Exposure to risk is greater in the absence of a standby run. Non-compliant stations are typically locations where surrounding developments have encroached within the hazardous zone, causing clearance concerns.

Sales Stations are the final pressure control point prior to entering into a customer's building. Leaks or loss of containment at a sales station can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets.

Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition or explosion within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators.

The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers. An analysis was conducted through the Asset Health Review to understand the projected failure rate of a specific obsolete model of regulator. The analysis determined its leak failure rate was eight times greater compared to the rest of the population.

The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions.

5.3.5.4 Strategy

A similar approach and strategy will be undertaken for each of the small stations programs for district, header, and sales stations. Station sites will continue to be assessed based on condition evaluation criteria to identify sites with reliability concerns which will be selected and prioritized into the replacement strategy.

District Station Rebuild Program

The District Station Rebuild Program is a compilation of ongoing maintenance capital projects targeting district stations that require rebuilding identified through the asset management condition and strategies approach. Execution of this program will maintain the current condition and operational reliability of district stations throughout the network, ensure operational capacity of district stations to meet ongoing system growth, and minimize process safety risk by ensuring code compliance

The District Station Rebuild Program strategy is to continuously inspect, collect information and remediate assets with the following issues:

- Below-ground boxes
- Sites with boot-style regulators
- Capacity issues
- Poor performance and poor condition
- Low pressure control
- Obsolete components

Prioritization of those stations will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, almost 200 stations have been identified with condition issues in need of remediation. Projects to address identified issues within the District Station Program will focus on a complete rebuild of the station site, including the removal and replacement of the pressure control components, valves, associated piping and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution and site restoration activities.

Operational reliability is based on improvements in asset condition and the ability to operate safely, but does not preclude the consideration of early retirement based on asset obsolescence. The District Station Rebuild Program strategy will be to maintain a consistent operational reliability profile throughout the duration of the Asset Management Plan.

The current asset management strategy includes the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. This strategy is aligned with the historical replacement pace for district stations, and has been found to maintain the reliability of district stations at a relatively consistent level over the next 40 years. **Figure 5.3-18** illustrates the projected failure events of the population by maintaining this current replacement rate.

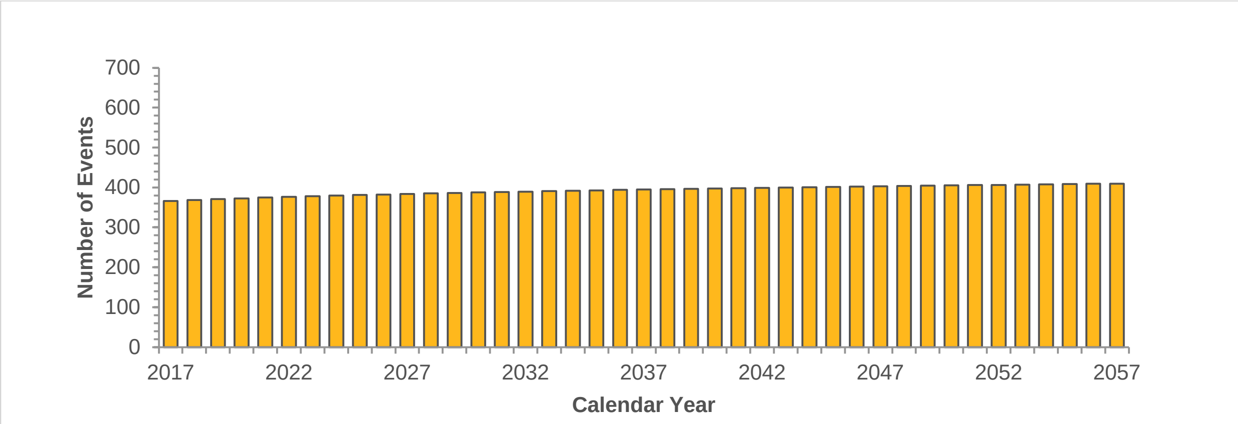


Figure 5.3-18: Projected Failure Events at District Stations

Applying an average replacement rate of 20 sites per year (which could vary depending on project complexity) indicates that the current average age is projected to remain under 40 years (**Figure 5.3-19**). A replacement rate of less than 20 sites per year could lower the reliability of the district station population, consequently increasing the projected failure events per year, which will result in increased risks.

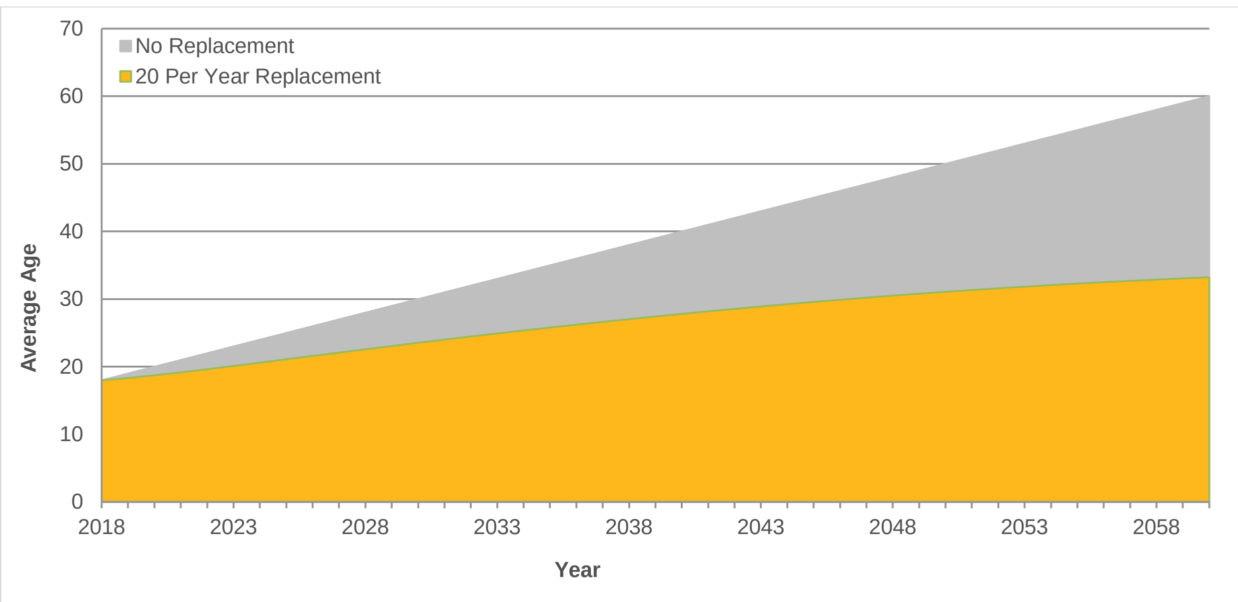


Figure 5.3-19: Average Age of District Stations with Replacement Strategy

The District Station Rebuild Program mitigates the risks associated with poorly performing stations. The risk associated with the potential failure of a district station can be significant. A single district station may feed hundreds of customers and the consequence of a station failure can affect all downstream mains and services. Depending on the severity or the station type, downstream regulators may not be able to adequately protect downstream customer piping and assets from experiencing the effects.

Header Station Rebuild Program

The Header Station Rebuild Program is a compilation of ongoing maintenance capital projects to target header stations that require rebuilding as identified through the asset management condition and strategies approach. Execution of this program will maintain the condition and operational reliability of header stations throughout the network, address sites with non-conforming configurations, and minimize process safety risk by ensuring code compliance.

The Header Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:

- Non-standard configuration
- Boot-style regulators
- Unsafe installation locations
- Poorly performing components
- Poor condition
- Obsolete components

Prioritization of those stations will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Header Station Rebuild Program will target stations that require rebuilding based on condition, age, and obsolescence. The program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated.

Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Header Station Rebuild Program's aim will be to maintain consistent operational reliability profile through the duration of the Asset Management Plan.

The historical replacement rate for the Header Station Rebuild Program has been approximately 50 stations per year. The asset management strategy includes the replacement of approximately 30 header stations per year, based on condition assessments and component age/obsolescence. Based on confirmation from SMAs it is recommended to reduce the focus on Header Station Rebuild Program, and increase the strategy within the Sales Station Replacement Program. This strategy is a reduction of the historical rebuild/replacement pace, and is expected to maintain the reliability of header stations at a relatively consistent level over the next 40 years. **Figure 5.3-20** illustrates the projected failure events of the population by maintaining the current replacement rate.

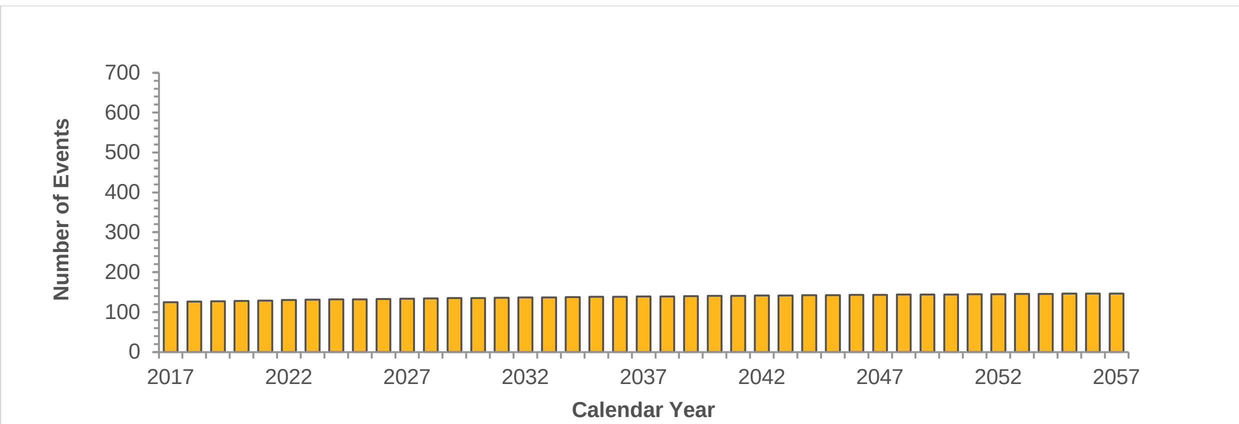


Figure 5.3-20: Projected Failure Events at Header Stations

Applying a 30-site replacement rate indicates that the current average age is projected to remain well under the age of 40 years (**Figure 5.3-21**). A replacement rate of less than 30 sites per year could lower the reliability of the header station population, consequently increasing the projected failure events per year, which will result in increased risks.

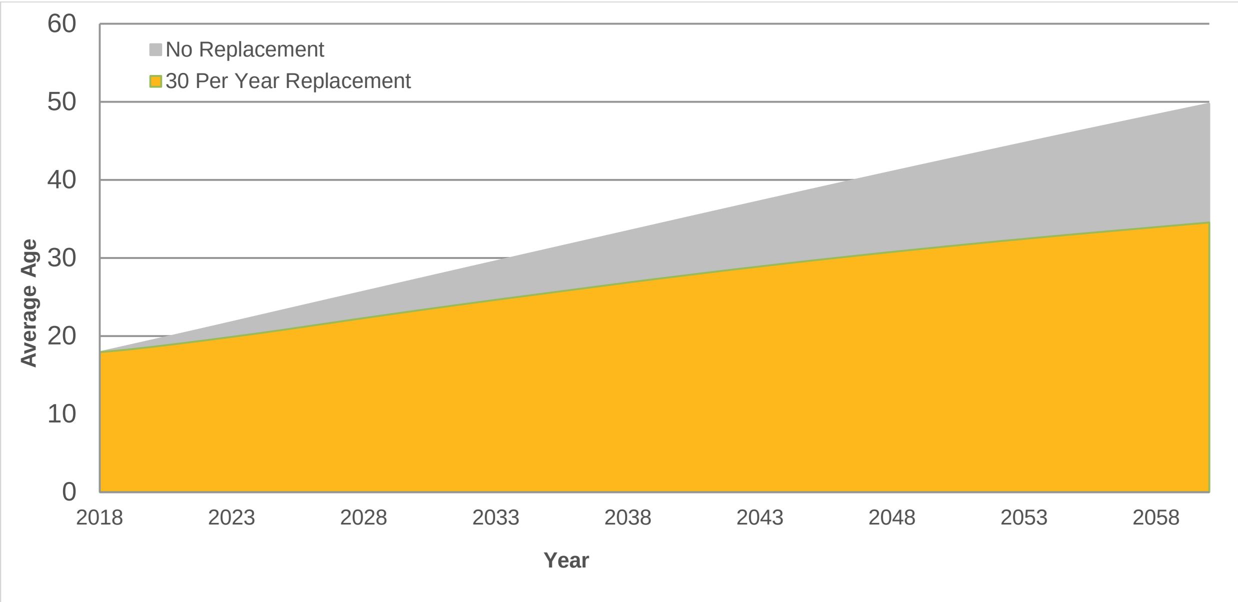


Figure 5.3-21: Average Age of Header Stations

The Header Station Rebuild Program mitigates the risks associated with poorly performing stations, as the potential failure of a header station may carry substantial risks. A single header station services hundreds of customer and the consequence of a station failure can be significant. Stations are evaluated to validate downstream customer impact, asset condition, and workers' health and safety to ensure maximum risk reduction and benefit for each replacement.

Sales Station Replacement Program

The Sales Station Replacement Program is a compilation of ongoing maintenance capital projects targeting sales stations that require rebuilding as identified through the asset management condition and strategies approach. Execution of this program will maintain reliable gas supply to customers, address sites with non-conforming configurations, and minimize high consequences to businesses and customers by ensuring code compliance.

Sales stations are the direct supply and control to commercial and industrial customers and the consequence of a station failure can be significant. Prior to rebuild, all stations are evaluated to validate customer impact, asset condition, and workers' health and safety to ensure maximum risk reduction and benefit for each replacement. Prioritization of those stations will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 440 sites have been identified with condition issues in need of remediation. Projects within the Sales Station Replacement Program will target stations that require rebuilding based on condition, age, and obsolescence.

Figure 5.3-22 illustrates the projected failure events of the sales station population by maintaining the current condition and reliability of existing station assets. Analysis suggests sales stations failure events are projected to increase slightly over time with the historical replacement strategy in place.

Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Management Plan. The Sales Station Replacement Program will target approximately 100 stations per year to address the following issues: non-standard configuration, unsafe installation locations, poor performing components, poor condition, and obsolete components.

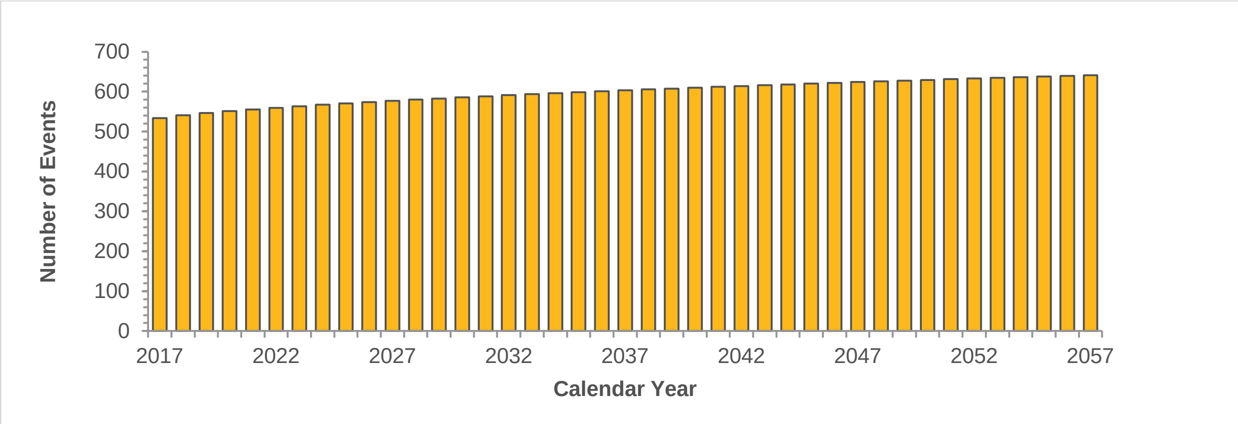


Figure 5.3-22: Projected Failure Events at Sales Stations

Applying an annual 100-site replacement rate (**Figure 5.3-23**) indicates that the current average age is projected to remain under the age of 40 years. A replacement rate of less than 100 sites per year could lower the reliability of the sales station population, consequently increasing the projected failure events per year, which will result in increased risks.

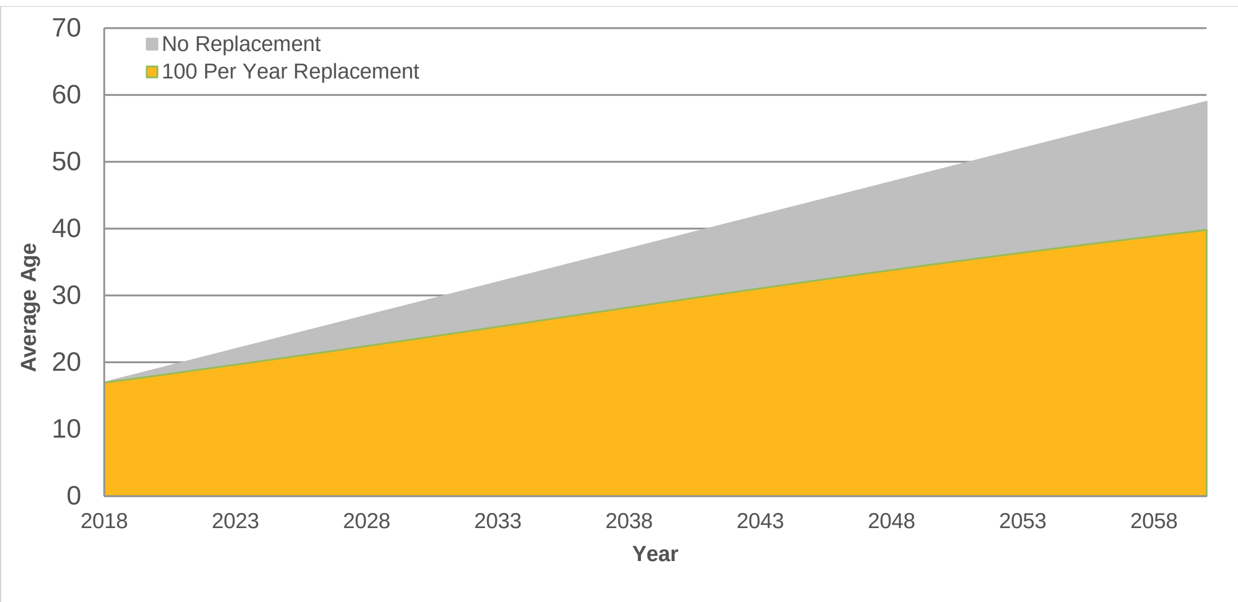


Figure 5.3-23: Average Age of Sales Stations

The conditions and risks associated with sales stations assets will continue to be monitored and assessed to determine if the current replacement rate is adequate in maintaining the operational reliability and risks associated with this asset type.

Inside Regulator Relocation and External Regulator Room Program

The Inside Regulator Relocation and External Regulator Room (ERR) Program is aimed at reducing the risks associated with having a pressure-reducing regulator inside a building by relocating the regulator to a lower risk location.

Inside regulators pose a public safety risk within the distribution system and to customers' properties because a loss of containment at or upstream of the regulator could potentially release gas into the building, resulting in a high consequence event. Inside regulators could potentially cause adverse downstream pressure (over-pressure) to customer piping in the event that the regulator vent to the exterior becomes blocked. Moving inside regulators outside of a building reduces this risk.

An inside regulator is defined as any of the following:

- A regulator that is clearly inside the building envelope (e.g., in a home, basement, garage, or indoor room)
- A regulator located in a room that is part of the building envelope or connected to the building envelope, where the enclosing walls, ceiling, and floor are not intentionally constructed to be air-sealed from the building to prevent gas migration into the building
- A regulator located in an air-sealed room that is part of the building envelope or connected to the building envelope, with no adequate ventilation to the outside

The scope of work involved in mitigating the public safety risk is to relocate the regulator to the exterior of the building envelope. An ERR is defined as an enclosed room with adequate ventilation that has not been specifically designed and approved to contain EGD regulators or stations. The scope of work for these locations involves remediating the room enclosure to ensure adequate ventilation to the exterior, and to modify enclosing walls to be air-sealed from the building to prevent gas migration.

All sales stations will continue to be monitored through station inspection programs and repaired as problems are detected. Stations found to be aging prematurely will be assessed to gain a better understanding of the factors influencing degradation. Sales stations are replaced if they are damaged by a third party, or as part of a mains replacement or relocation program. The following approaches to address risks to sales stations have been identified:

- Replace poor performing components as they fail (reactive)
- Station replacement/rebuild program based on field condition assessments (proactive)

The Asset Health Review indicates that the timing of the current proactive replacement programs has optimized the projected failure rates on stations. As EGD conducts further analysis and gains a better understanding of asset conditions, the station rebuild programs will be adjusted accordingly if it is found that the replacement rate does not meet the objectives of the strategy.

5.3.6 Stations Capital Expenditure Summary

The summary of projects and programs under the Stations asset class accounts to $217M from 2019 to 2028, as summarized in **Table 5.3-10**. The Stations capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.3-10: Stations Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Gate & Feeder Station Program	7,504	12,987	7,741	11,469	8,652	13,051	7,240	6,848	3,612	3,484	82,586
District Stations Rebuild Program	6,500	8,189	7,000	8,000	7,500	7,500	7,500	7,500	7,500	8,500	75,689
Header Stations Rebuild Program	924	924	924	924	924	924	924	924	924	924	9,240
Sales Stations Rebuild Program	1,100	1,500	2,000	2,035	2,071	2,107	2,144	2,181	2,219	2,258	19,615
Inside Regulator Relocation and ERR Program	500	500	500	500	500	500	500	-	-	-	3,500
Integrity Retrofits	2,573	1,850	1,197	1,500	1,400	450	-	-	-	-	8,971
Telemetry Program	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	14,000
M&R Compliance	200	200	200	200	200	200	200	200	200	200	2,000
Station Emergency Replacement	200	200	200	200	200	200	200	200	200	-	1,800
Stations Total	**20,901**	**27,750**	**21,163**	**26,228**	**22,846**	**26,332**	**20,108**	**19,253**	**16,055**	**16,766**	**217,401**

5.4 STORAGE

Storage assets are located in three areas of southwestern Ontario: St. Clair Township near Sarnia, Crowland Township in Welland, and in Chatham-Kent.

Operations in St. Clair Township employ over 40,000 HP of combined reciprocating compression at the Sombra and Corunna compressor stations. Total storage working inventory is approximately 114.6 BCF (91.3 BCF EGD regulated, 6.7 BCF UGL volumes, and 16.6 BCF unregulated). Gas is received from the UGL Dawn and Vector pipeline systems and delivered to UGL Dawn. Daily winter flows are transported to EGD's central delivery area via the UGL Dawn Parkway system.

Operations in Chatham-Kent employ 1050 HP of reciprocating compression at the Chatham D compressor station. The total storage working volume accounts approximately 1.3 BCF (100% regulated). Gas is received and delivered into the UGL Panhandle system. Chatham D contributes to the regulated gas winter delivery by backfeeding through UGL Dawn. Chatham D also contributes to late season delivery by shifting inventory to higher deliverability reservoirs in St. Clair Township.

Operations in Crowland Township employ 800 HP of reciprocating compression at the Crowland compressor station. The total storage working volume account for approximately 0.3 BCF (100% regulated). Gas is received from the TransCanada Pipeline (TCPL) at Blackhorse and delivered to EGD's Niagara region. Crowland's strategic location allows it to perform load balancing for EGD's central delivery area on short notice.

All three of the Storage operating areas are isolated from one another by non-EGD piping networks (see **Figure 5.4-1**).

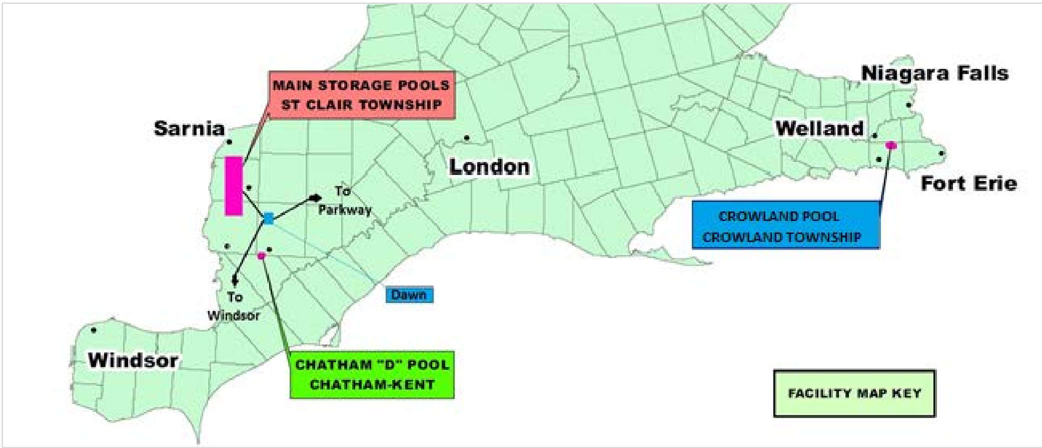


Figure 5.4-1: EGD Gas Storage Operations Locations

Storage operates assets in both regulated and unregulated environments. The Storage asset class includes:

- Compressor Stations: compression and flow control facilities that move gas to and from reservoirs.
- Pipelines: pipe that transports gas between custody transfer points and reservoirs.
- Reservoirs: storage area that traps and holds natural gas.

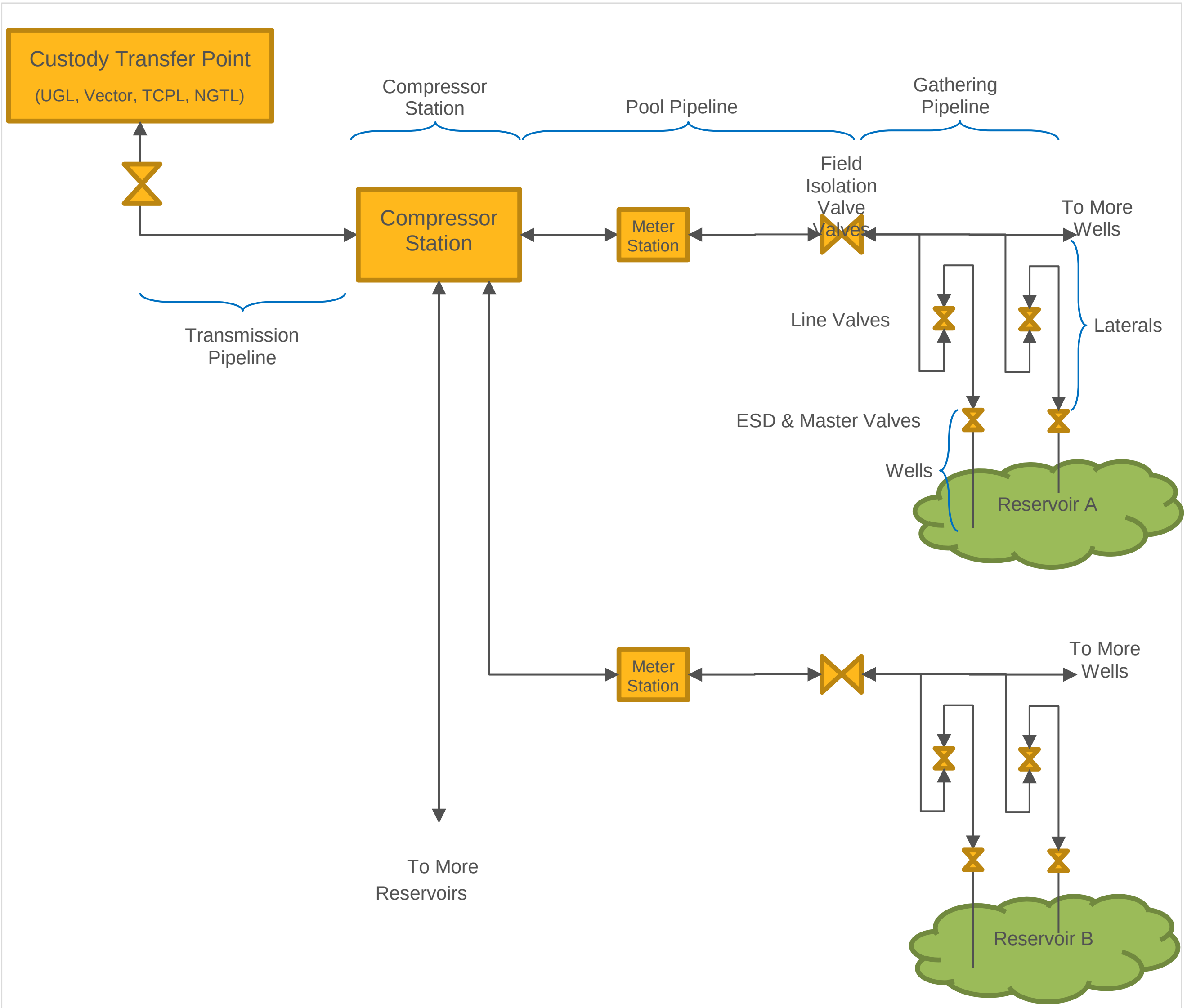


Figure 5.4-2: EGD Storage Operations Diagram

Storage is different from other gas carrying asset classes in that all reservoir, pipeline, and compression assets can accommodate the following:

- Bi-directional gas flow
- High moisture content and liquids
- Unodourized gas
- Higher operating pressures
- Higher SMYS
- Gas compression

Storage gas is unodourized, requiring the use of gas and flame detection systems inside compressor buildings, which can trigger an Emergency Shutdown (ESD). Once triggered, an ESD system is designed to isolate and vent compressor station piping by closing Emergency Shutdown valves. During an emergency event, the ESD system provides primary protection of personnel and the public, and minimizes damages to infrastructure.

During periods of early injection to and withdrawal from gas reservoirs, gas flows into storage without the need for compression. During these free flow intervals (also known as 'shoulder months'), only control valves are needed to throttle storage gas in a way that achieves daily nominations established by the Gas Control group. Maintenance is conducted on compression systems at this time. The transition from early to late season injections and withdrawals and vice-versa requires increasing levels of compression. Maximum compression requirements occur during late injection and withdrawal.

Storage asset requirements are influenced by the presence of reservoir liquids in the gas system. During injection, moisture content and liquids are insignificant because gas is dry (pipeline quality). Reservoir gas, on the other hand, quickly increases to 100% relative humidity. In addition, as reservoir pressure decreases during withdrawal, liquids (water, brine, and crude oil) begin to appear in the storage gas. Many Storage assets are dedicated to removing liquids and reducing gas moisture to pipeline-quality levels.

An inventory overview shows Storage is comprised of both repairable and replacement assets that deteriorate steadily over time, wear out, or become obsolete, and require eventual replacement. Most Storage assets are repairable:

- **Stations**: Key compressor sub-systems like pistons, cylinder liners, valves, foundations, crankshafts, bearings, etc. are all designed with a finite life expectancy. A decision to replace the entire compressor would be based on comparison with the long term costs/risks associated with sustaining the existing compressor equipment.
- **Pipelines**: Localized corrosion can be cut out and replaced with a new segment.
- **Reservoirs**: Localized corrosion on the top 20 meters of well casing can be removed and replaced.

The following assets are examples of replacement (non-repairable) assets:

- **Atmospheric holding tanks**: Internal corrosion is usually pervasive - replacement is more cost- and risk-effective compared to replacing a section or installing localized repair patches.
- **Wells**: Localized corrosion at a depth greater than 20 meters cannot be repaired or replaced, and must be retired as prescribed by code.

Under certain circumstances total replacement of repairable assets can become necessary.

5.4.1 Storage Objectives

The life cycle management objectives for the Storage asset class are listed in **Table 5.4-1**.

Table 5.4-1: Storage Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
System Integrity and Reliability	Maintain the gas storage system to meet or exceed standards for safety and operational effectiveness.	• Meet Scorecard metrics: o Safety/Environmental metric o Incident/Asset Rupture o Spills/Orders/Charges • GHG emissions reduction (measured in fugitive emissions and fuel consumption reporting) • Leak Management o Completion of Leak Survey Program o Completion of leak repair investigations • Corrosion Management o Completion of corrosion inspections
	Utilize cost, risk and performance information to drive asset-related decisions.	• Risk mitigated and LRROI • QRA Completion %
	Continuously evolve the understanding of condition and risk associated with gas storage assets.	• Number of pressure vessels and tanks inspected • FIMP, TIMP and SDIMP KPIs: o Completion of storage well integrity inspections o Completion of well inspections logging and follow up o Completion of well integrity permanent remediation o Completion of pipeline inspections
System Performance	Ensure reliable delivery of natural gas by delivering on 100% of Storage service commitments	• Meet nominations set by Gas Supply (GJs) • Compressor service usage from Dawn • Meet Scorecard metrics:

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
		o Completion of preventative maintenance o Number of unplanned compressor outages from September to November, and during February and March o Actual deliverability available as a % of design deliverability (monthly average)
	Optimize overall efficiency and performance of gas storage assets.	• Fuel consumption and maintenance costs trended against Annual Turnover Volume • Predicted Fuel Consumption Variance (Synergi) vs. actual variance • Year-end gas Lost and Unaccounted For (LUF) estimation

To achieve these objectives, asset investment decisions are governed by Life Cycle Management policies in **Table 5.4-2**.

Table 5.4-2: Life Cycle Management for Storage Assets

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Design gas storage installations to: - Ensure worker and public safety - Ensure regulatory compliance - Meet demand requirements and performance standards - Reduce risk to the lowest practicable level - Ensure critical components and systems have multiple layers of failure protection - Minimize environmental impact - Ensure components can be made safe in a reasonable period of time - Minimize future maintenance needs • Procure materials to meet or exceed codes, standards and policies • Install storage assets to meet or exceed codes, standards, designs, and procedures for safe and reliable operations • Create asset records to meet or exceed standards, policies, and procedures that are traceable, verifiable, complete and correct
Utilize	• Operate the gas storage system to: - Ensure worker and public safety - Meet or exceed compliance standards and established procedures - Meet current demand - Ensure reliable gas delivery - Minimize end user disruption - Utilize the assets in the most cost effective manner - Extend asset life • Monitor the performance and utilization of storage assets to inform future life cycle decisions
Maintain	• Maintain integrity of assets to minimize loss of containment, extend asset life and ensure compliance with codes, standards and established procedures • Maintain assets and safety controls to avoid over pressure or delivery outage • Maintain gas storage assets to achieve a failure probability that is consistent with the expectations of EGD’s Gas Supply department and reduces risk to the lowest practicable level • Maintain asset information to comply with Enbridge internal standards • Determine probability and consequence of failure to inform maintenance and repair programs • Maintain competency levels to ensure work is performed by qualified and competent workers • Continue to understand and mitigate factors that contribute to LUF gas and GHG emissions
Renew/Retire	• Determine probability and consequence of failure to inform renewal decisions • Develop proactive renewal programs for assets that are nearing end-of-life (informed by data and tacit knowledge and housed within the Integrity Management System) • Abandon/Retire assets using a process that meets or exceeds codes and standards

5.4.2 Storage Inventory

Compressor stations, pipelines, and reservoirs are categorized based on function as summarized in **Figure 5.4-3**. Note that this Asset Management Plan does not detail unregulated assets.

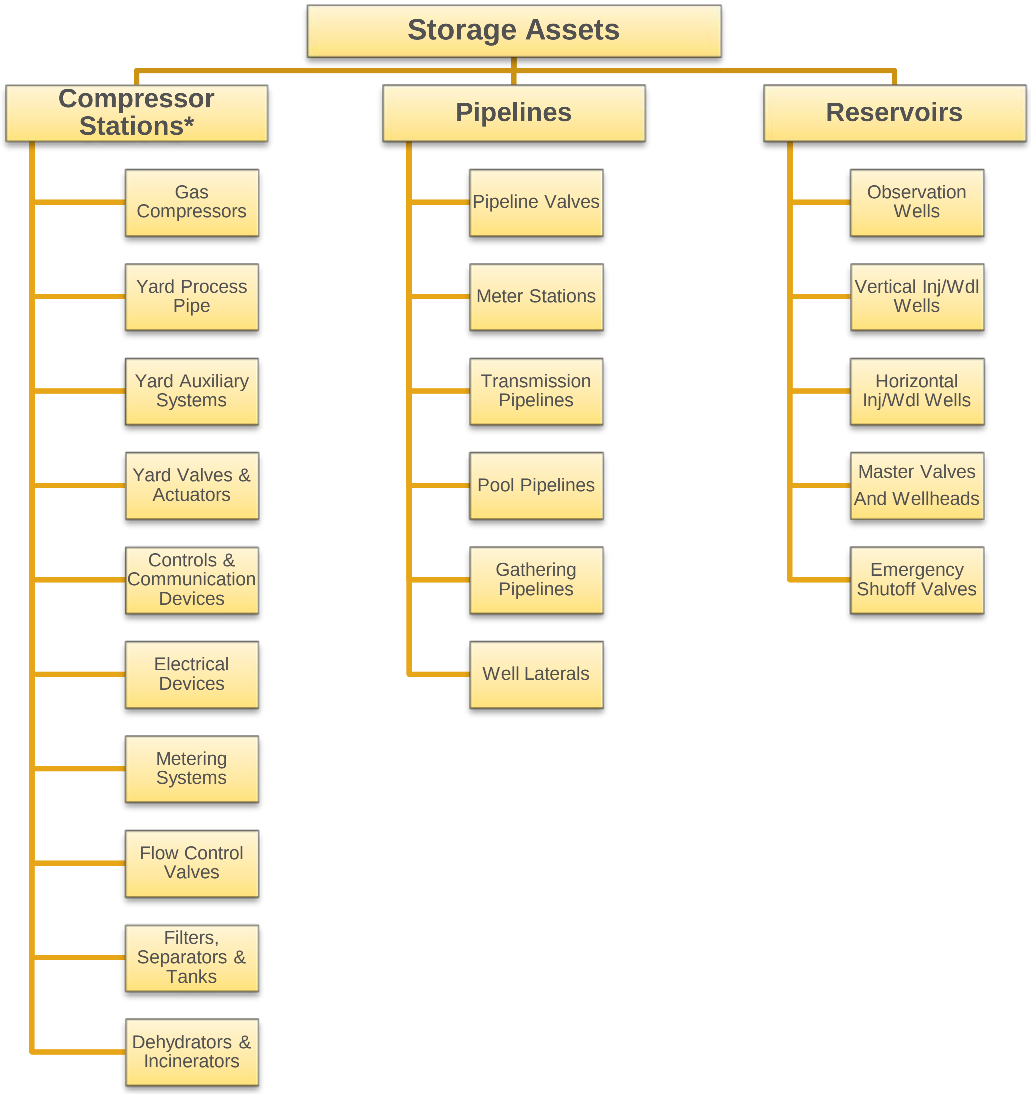


Figure 5.4-3: Storage Asset Classification

*There are four gas compressor stations:

- Corunna Compressor Station (SCOR)
- Chatham D Compressor Station (SCHT)
- Sombra Compressor Station (SSOM)
- Crowland Compressor Station (SCRW)

The asset inventory for the Storage asset class is presented in **Table 5.4-3**.

Table 5.4-3: Storage Asset Class Inventory[8]

SUB ASSET CLASS	QUANTITY
Compressor Stations	
Gas Compressors	16
Yard Process Pipe	15 km
Yard Auxiliary Systems	See notes below.
Yard Valves and Actuators	420
Controls and Communication Devices	See notes below.
Electrical Devices	See notes below.
Metering Systems	See notes below.
Flow Control Valves	25
Filters, Separators & Tanks	395
Dehydrators & Incinerators	3
Pipelines	
Pipeline Valves	310
Meter Stations	8
Transmissions Pipelines	50 km
Pool Pipelines	45 km
Gathering Pipelines	20 km
Well Laterals	10 km
Reservoirs	
Observation Wells	29
Vertical Injection/Withdrawal Wells	96
Horizontal Injection/Withdrawal Wells	10
Master Valves and Wellheads	127
ESD Valves	6

Notes

- **Gas compressor assets** include: foundations, crankshaft assemblies, engine assemblies, compressor assemblies, gas aftercoolers, heating & cooling systems, and valve systems.
- **Yard Auxiliary Systems** include: auxiliary yard piping, air compressors, boilers, blowdown silencers, oil/water separators, flares, fire pumps, fire pond, compressor building structures, liquids collection tanks, centralized fuel gas conditioning and metering systems.
- **Controls and Communication Devices** include: SCADA (including Human Machine Interfaces (HMIs) and video screens), Programmable Logic Controller (PLC) systems, control rooms, fibre optics, radio assets, Remote Telemetry Unit (RTU) systems, Uninterruptible Power Supply (UPS) systems, and field instruments & controllers. Control Rooms contain additional assets including industrial data centres, historian servers, HMIs, and video walls.
- **Electrical assets** include: auxiliary power units, transformers, motor control centres, variable frequency drives, lighting systems and phase inverters.
- **Meter System and Meter Station assets** include: process meter runs, custody transfer meters, gas chromatographs and fuel gas meters.

[8] Inventory incorporates regulated and unregulated asset counts.

5.4.3 Storage Condition and Strategy Overview

5.4.3.1 Compressor Stations

ASSET SUBCLASS			AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Gas Compressors	Corunna (SCOR)	**Foundations**	36	The Corunna compressor has reduced technical support from the manufacturer. Compressor foundations are deteriorating, causing bearing failures and bent crankshafts. Foundations for K705 and K706 were recently replaced. Except for K701/2/3, engine and compressor assemblies are in fair condition. K701/2/3 units are experiencing very poor reliability. Gas aftercoolers (GAC) and Jacket Water Coolers (JWC) have undergone fan drive retrofits. However, tube bundles are original for all units except for K704 GAC. Mode valves, which are manifolded to the header system, are all original and unable to provide a sufficient seal when the valve is in the closed position. Mode valve seal quality is considered to be in poor condition.	Age and operating hour issues are key risk influencers. Compressor component failures are key threats that pose the following risks: *Safety Risk*: • Risk of crankshaft and engine frame failure can result in significant collateral damage to units with a direct influence on safety risk to employees. • Valves which do not seal create a process safety risk during an Emergency Shutdown (ESD) event and to personnel. • Crowland unit valve configuration is a process safety concern because valves are manually actuated with no loading valve. Manually actuated valves do not accommodate automatic ESD strategies *Financial Risk*: Reciprocating compressor failures (unplanned outages) results in unexpected repair costs (both materials and labour) and frequently involves collateral damage. *CSAT Risk*: Unplanned unit failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.	The maintenance strategy to maintain compressor stations is to: • Conduct preventative maintenance inspections prescribed by the manufacturer • Continue adhering to the current Valve Maintenance Program	EGD's replacement/renewal strategy to maintain the Corunna compressor station is to: • Replace deteriorating compressor foundation blocks. • Evaluate options for replacement of K701/2/3 compressor units and perform a Front-end Engineering Design (FEED) study of the selected replacement option. • Continue to overhaul compressor and engine assemblies. • Mitigate obsolescence of sub-systems and auxiliary systems. • Proactively replace obsolete systems/devices and upgrade with new technology. • Upgrade units to minimize air emissions. • Proactively replace JWCs. • Continue to enhance understanding of asset health and life cycle cost for compression facilities. • Gas compressor upgrades are expected to comply with anticipated restrictions on methane releases to atmosphere. • Replace bypass valve. Reliability issues related to K701/2/3 are expected to be sufficiently large to warrant their retirement. A comprehensive assessment of solution options is currently underway.
		Crankshaft Assemblies	45				
		Engine Assemblies	45				
		Compressor Assemblies	43				
		Gas Aftercoolers (GAC)	40				
		Heating & Cooling System	45				
		Valve Systems	45				
	Sombra (SSOM)	**Foundations**	17	SSOM compression is 20 years old and considered to be in good condition.			EGD's replacement/renewal strategy to maintain the SSOM compressor station is to: • Perform minor compressor and engine assembly overhauls per Original Equipment Manufacturer (OEM) recommendations. • Continue to enhance understanding of asset health and life cycle cost for compression facilities. • Replace bypass valve.
		Crankshaft Assemblies					
		Engine Assemblies					
		Compressor Assemblies					
		Gas Aftercoolers					
		Heating & Cooling System					
		Valve Systems					

ASSET SUBCLASS			AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
	Chatham D (SCHT)	**Foundations**	20	Chatham D compression is 20 years old and considered to be in good condition.			EGD's replacement/renewal strategy to maintain the Chatham D compressor station is to: • Perform minor compressor and engine assembly overhauls per OEM recommendations. • Continue to enhance understanding of asset health and life cycle cost for compression facilities.
		Crankshaft Assemblies					
		Engine Assemblies					
		Compressor Assemblies					
		Gas Aftercoolers					
		Heating & Cooling System					
		Valve Systems					
	Crowland(SCRW)	**Foundations**	47	Crowland is considered to be in fair condition. Crowland is almost 50 years and is an older vintage compressor. It is anticipated that the valve systems are likely to exhibit condition concerns. The compressor unit typically operates for approximately 650 hours per year. Crowland has been identified as requiring additional noise mitigation measures.			EGD's replacement/renewal strategy to maintain the Crowland compressor station is to: • Replace/modify compression to optimize operational reliability, process safety, and personnel safety, and ensure long term sustainability. • Implement noise mitigation measures to be in compliance with environmental regulations. • Continue to enhance understanding of asset health and life cycle cost for compression facilities.
		Crankshaft Assemblies					
		Engine Assemblies					
		Compressor Assemblies					
		Gas Aftercoolers					
		Heating & Cooling System					
		Valve Systems					
Yard Process Pipe		**Corunna (SCOR)**	45	Yard process pipe is generally thought to be in good physical condition (as it relates to corrosion). Corunna threats to process safety include: • Material of unknown notch toughness • Piping vibration • Thermal growth • Legacy pipe designs	Yard process piping systems provide support to gas compressors. A significant failure can affect multiple gas compressor units. The risks associated with not maintaining yard process piping are: *Safety Risk*: A loss of containment causing leaks and creating flammable mixtures has the potential to injure workers. *Financial Risk*: Failures can cause moderate damage to company facilities, requiring repair costs. *CSAT Risk*: Failures can result in loss of Storage deliverability, therefore reducing operational reliability. Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost.	The maintenance strategy to maintain yard process pipe assets is to: • Ensure external coatings are re-applied regularly to prevent external corrosion of above grade pipe. • Regularly inspect performance of cathodic protection systems. • Inspect pipe condition (i.e., Facilities Integrity Management Program (FIMP)) for evidence of any threat to pipe condition.	EGD's replacement/renewal replacement/renewal strategy for yard process pipe assets is to: • Perform an assessment of the cross-flow header system to understand the extent and impact of the experienced vibration. The mitigation option being investigated is to replace the above-grade cross-flow header system and process piping at Corunna. A FEED study is currently underway to further evaluate design options. • Replace used pool inventory meters and associated yard piping at Corunna with modern buried pipe. • Continue FIMP and Hazard and Operability Study (HAZOP) assessments across all compressor stations.
		Sombra (SSOM)	19				
		Chatham D (SCHT)	20				
		Crowland (SCRW)	42				

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Yard Auxiliary Systems	**Corunna (SCOR)**	38	Yard auxiliary systems are generally thought to be in good physical condition (as it relates to corrosion). Corunna factors influencing condition include piping vibration and legacy pipe designs.	Yard auxiliary systems provide support to gas compressors - a significant failure can affect multiple gas compressor units. The risks associated with not maintaining yard auxiliary systems are: *Safety Risk*: Loss of containment causing leaks and creating flammable mixtures has the potential to injure workers. *Financial Risk*: Failures can cause moderate damages to company facilities, requiring repair costs. *CSAT Risk*: Failures can result in loss of Storage deliverability, therefore reduced operational reliability. Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost.	The maintenance strategy to maintain yard auxiliary systems is to: • Ensure external coatings are re-applied regularly to prevent external corrosion of above-grade pipe. • Regularly inspect performance of cathodic protection systems. • Inspect pipe condition (i.e., FIMP) for evidence of any threat to pipe condition.	EGD's replacement/renewal replacement/renewal strategy for yard auxiliary assets is to: • Proactively replace obsolete yard auxiliary system components. • Overhaul the start air compressors at Corunna. • Upgrade the existing air compressor at Chatham D. • Upgrade and expand the existing on-site firewater protection system. • Design and install a knock-out drum and metering system for the existing maintenance flare.
	Sombra (SSOM)	16				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	25				
Yard Valves & Actuators	**Corunna (SCOR)**	33	Valve actuators are generally repairable until parts are no longer available. Valve seal quality diminishes slightly with each actuation and is influenced by age, cycling frequency, and amount of abrasive debris in the gas stream. Many valves are believed to have poor seal quality and represent a threat to containment during an emergency event.	Process safety risks need to be mitigated due to poor seal quality. Failures due to poor seal quality pose financial and customer satisfaction risks. *Safety Risk*: Inadequate gas containment by valves caused by actuator or seal failure during an emergency situation has the potential to injure workers and the public. *Financial Risk*: Failure of yard valves & actuators to operate as designed during an Emergency Shutdown (ESD) has the potential to exacerbate damage to non-company infrastructure, and commodity loss. *CSAT Risk*: Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.	The maintenance strategy to maintain yard valves & actuators is to: • Assess actuator condition, based on frequency of repairs. • Assess valve condition based on Subject Matter Advisors (SMA) input and direct measurement. Future inspection methodologies are being evaluated. • Complete the valve maintenance program.	EGD's replacement/renewal strategy for yard valves & actuators is to: • Upgrade the valve actuators at SSOM to address obsolescence. • Overhaul the valve actuators at Chatham D to address poor condition. • Replace yard valves at Corunna to address poor seal quality.
	Sombra (SSOM)	16				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	30				
Control & Communicatio n	**Corunna (SCOR)**	20	The physical condition of these assets is good. A summary of the key condition conclusions is as follows: • Obsolete equipment is approaching end-of-life (radios, field instruments/controllers, and Programmable Logic Controllers (PLC)) • A growing number of systems at SSOM, Chatham D, and meter stations require access to the telemetry system, exceeding the bandwidth provided by existing infrastructure. • Inadequate climate control: o Chatham D: New devices have been installed on an external wall to accommodate increasing instrumentation demands.	Failure of these assets primarily exposes EGD to financial and customer satisfaction risks. Parts unavailability or delays can lead to longer downtime when a failure occurs.	The maintenance strategy for control & communication equipment is to monitor parts availability and introduce generational changes in product lines.	EGD's replacement/renewal strategy for control & communication equipment is to: • Upgrade and replace obsolete radio communication devices. • Install and upgrade the server, software, and hardware components of the primary operating interfaces (between the operator and the control of the assets) approaching end-of-life. • Maintain the prescribed replacement of industrial data centres. • Upgrade PLCs to maintain manufacturer supportability. • Expand and update the Chatham D control room with climate controls, Uninterruptible Power Supply (UPS) redundancy and security systems.
	Sombra (SSOM)	20				

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
	Chatham D (SCHT)	20	o SSOM: The current Local Area Network (LAN) facility consists of a panel located in the open and with minimal security. • UPS systems are experiencing battery degradation.			• Install individual fibre optics links from Corunna to core facilities in the Storage system. • Develop training material, including simulated situations and expected scenarios. • Install industrial wireless service, obtain field equipment to securely access, and update operational records. • Upgrade the Supervisory Control and Data Acquisition (SCADA) system to ensure electronic control systems are configured, updated, and secured. • Upgrade radio frequency communication links between Tecumseh, Mid/South Kimball, Sombra, and Wilkesport compressor/meter stations. • Upgrade Instrumentation and Electrical (I&E) controls at SSOM and connect them to existing remote input/output devices. • Install a LAN room at SSOM with climate controls and security systems.
	Crowland (SCRW)	20				
Electrical Devices	**Corunna (SCOR)**	21	The physical condition of these assets is good, with older systems being fair. A summary of the key condition conclusions is as follows: • The existing transfer switch (used to control up to 600 VAC, three-phase circuits) which requires the entire plant be de-energized and de-pressurized to perform maintenance/repairs is approaching end-of-life. • Existing gas aftercoolers are On/Off type fan drives, which consume more hydro power and require more maintenance. • The inverter at Chatham D has been identified by SMAs as having poor reliability (frequent failures requiring repair) and is approaching end-of-life. • Older light poles have been identified to have corrosion, specifically at the base of the light pole, jeopardizing structural integrity.	Failure of these assets primarily exposes EGD to financial and customer satisfaction risks. Parts unavailability or delays can lead to longer downtime when a failure occurs.	The maintenance strategy for electrical assets is to monitor parts availability and introduce generational changes in product lines.	EGD's replacement/renewal strategy for electrical assets is to: • Replace the existing transfer switch with a new unit employing a wrap-around bypass. • Replace existing On/Off cooling fan motor starters with variable frequency drives. • Replace light poles that are showing signs of corrosion. • Replace phase inverters experiencing reliability concerns.
	Sombra (SSOM)	15				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	34				
Metering Systems	**Corunna (SCOR)**	22	Most metering systems located in compressor stations are 20 years old or less. Metering systems have a long life expectancy but can be vulnerable to obsolescence. The Black Creek inventory management meter is obsolete and no longer supported by the manufacturer.	Failure of these assets primarily exposes EGD to financial and customer satisfaction risks. Parts availability can lead to longer downtime when a failure occurs. Not maintaining these assets poses the following risks: *Safety Risk*: Loss of containment has the potential to injure workers and the public if asset condition is allowed to degrade, causing leaks and creating	The maintenance strategy for metering systems is to monitor parts availability and introduce generational changes in product lines.	EGD's replacement/renewal strategy for metering systems is to: • Upgrade the obsolete and unsupported ultrasonic meters at SSOM with new units. • Continue to enhance the understanding of asset health and life cycle costs for the metering system, flow control valves, and dehydrators & incinerators.
	Sombra (SSOM)	18				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	N/A				

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Flow Control Systems	**Corunna (SCOR)**	19	Flow control systems located in compressor stations are 20 years old or less. Flow control systems have a long life expectancy but can be vulnerable to obsolescence.	flammable mixtures. *Financial Risk*: Key financial risk drivers are escalating cost of parts for obsolete equipment, potential for third party and company damages, commodity loss, and environmental cleanup. *CSAT Risk*: Obsolete equipment can cause extended outage durations. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single failure within this grouping of assets can shut down an entire compressor station.	The maintenance strategy for flow control systems is to monitor parts availability and introduce generational changes in product lines.	EGD's replacement/renewal strategy for flow control systems is to continue to enhance the understanding of asset health and life cycle costs for the metering system, flow control valves, and dehydrators & incinerators.
	Sombra (SSOM)	14				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	30				
Dehydrators & Incinerators	**Corunna (SCOR)**	N/A	These assets are normally custom built, so they are minimally vulnerable to obsolescence. The condition of these assets is characterized by internal corrosion and condition of re-boiler fire tube. Dehydrators and incinerators have a very long life expectancy. Currently, all dehydrators and incinerators are fully automated, with the exception of the unit at Chatham D.		The maintenance strategy for dehydrators & incinerators is to: • Ensure external coatings are regularly re-applied to prevent external corrosion of vessels. • Continue to implement the pressure vessel and tank inspection program under FIMP.	EGD's replacement/renewal strategy for dehydrators & incinerators is to: • Upgrade the dehydrator and incinerator at Chatham D to a fully automated unit, allowing remote operator visibility and control. • Continue to enhance the understanding of asset health and life cycle costs of these assets.
Filters, Separators & Tanks	**Corunna (SCOR)**	45	These assets are normally custom built, so they are not vulnerable to obsolescence. The condition of these assets is characterized by internal corrosion. Filters and separators have a very long life expectancy. Atmospheric tanks are generally constructed with much thinner walls (corrosion potential). Asset condition is being assessed via a new inspection program. Approximately half of these assets have been inspected. Most pressure vessels and tanks are in good condition. The condition of a small portion of inspected liquids tanks (such as Chatham D) is very poor. A consolidated condition report is in progress.	Not maintaining filters, separators, and tanks poses the following risks: *Safety Risk*: Loss of containment has the potential to injure workers and the public if asset condition is allowed to degrade, causing leaks and creating flammable mixtures. *Financial Risk*: Key financial risk drivers are escalating cost of parts for obsolete equipment, potential for third party and company damages, commodity loss, and environmental cleanup. *CSAT Risk*: Atmospheric tanks can suffer from wall/weld corrosion leading to an environmental spill. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.	The maintenance strategy for filters, separators, & tanks is to: • Ensure external coatings are regularly re-applied to prevent external corrosion. • Continue to implement the pressure vessel and tank inspection program under FIMP.	EGD's replacement/renewal strategy for filters, separators, & tanks is to: • Complete the development of the Pressure Vessel and Tanks Inspection Program. • Develop a more complete understanding of life cycle costs for filters, separators & tanks. • Develop forecasting tools to predict appropriate timing for filter, separators, & tank replacements. • Replace filter and separator vessel closures that pose a potential hazard to maintenance personnel. • Replace tanks and associated secondary containment identified to be in poor condition. • Replace atmospheric tanks with pressure vessels designed to connect with high-pressure, low-point drain systems. • Design and install platforms for worker safety when changing filter elements and working around separators.
	Sombra (SSOM)	17				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	47				
	Sombra (SSOM)	10				
	Chatham D (SCHT)	20				
	Crowland (SCRW)	19				

5.4.3.2 Pipelines

<table>
<tr><th colspan="2">ASSET SUBCLASS</th><th>AVG. AGE (YR)</th><th>CONDITION</th><th>RISK / OPPORTUNITY</th><th>MAINTENANCE STRATEGY</th><th>REPLACEMENT / RENEWAL STRATEGY</th></tr>
<tr><td rowspan="6">Pipelines</td><td>Transmission</td><td>41</td><td rowspan="3">In-line inspections for all pipelines are completed. No issues currently require remediation. Asset condition is considered good.</td><td rowspan="4">Not maintaining pipelines poses the following risks:
Safety Risk: Loss of containment could have a major influence on public and employee safety.
Financial Risk: Unexpected pipeline failures carry a large cost of replacement.
CSAT Risk: Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost. The outage duration will depend on the magnitude of the failure.</td><td rowspan="4">The maintenance strategy for pipelines is to:
Ensure external coatings are re-applied regularly to prevent external corrosion of above-grade pipe.
Regularly inspect performance of cathodic protection systems.
Inspect pipe internal condition (i.e., TIMP) for evidence of any threat to pipe condition
Perform ILIs every seven years.
Track changes in asset condition over time using direct measurements.</td><td rowspan="4">EGD’s replacement/renewal strategy for pipelines is to:
Continue to assess the condition of pipelines, perform regular ILIs and employ condition data to forecast the timing of proactive replacements.
Maintain adequate cathodic protection systems to protect the pipelines from corrosion.
Reactively replace well loop piping under strain due to buried pipe settlement discovered through reservoir maintenance work.
Install pressure-indicating transmitters at the pipeline entry point into compressor stations to validate the performance of the storage pipeline system.</td></tr>
<tr><td>Pool</td><td>31</td></tr>
<tr><td>Gathering</td><td>38</td></tr>
<tr><td>Laterals</td><td>36</td><td>All laterals will be 100% inspected by 2019. Asset condition is considered good.
During work activities involving the removal of lateral loops, it has been found that there is inadequate pipe support due to settlement of the soil surrounding laterals. The weight of the pipe is supported by the well loop which attaches to the lateral to the well.</td></tr>
<tr><td>Pipeline Valves</td><td>12</td><td>Most pipeline valves are line valves located at the end of every lateral. Many of these valves were replaced to accommodate ILIs.
SMAs have indicated that many pipeline valves are known to have seal quality deterioration to such an extent that they are deemed unreliable during certain maintenance activities.</td><td>Not maintaining pipelines poses the following risks:
Safety Risk: Inadequate gas containment by valves during an emergency situation has the potential to injure workers and the public if actuators fail to operate or if valve seals fail to fully isolate.
Financial Risk: Failure of pipeline valves to operate as designed during an ESD has the potential to exacerbate damage to non-company infrastructure and incur commodity loss.
CSAT Risk: Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.</td><td>The maintenance strategy for pipeline valves is to:
Assess valve condition based on SMA input and direct measurement or observation.
Complete the Pipeline Valve Inspection Program.</td><td>EGD’s replacement/renewal strategy for pipeline valves is to:
Target replacement of pipeline valves and actuators to the extent needed to mitigate process safety risks. Valve replacements will be based on recent experience and understanding of SMAs.
Replace pipeline valves employed in transmission pipelines, gathering pipelines and laterals to address poor seal quality.
ESD bottles, located on many gas-powered valve actuators will be upgraded to ensure that pressure relief valves (PSV) can continue to be removed and inspected annually as required by CSA Z662.
Pursue opportunities to improve operations effectiveness by increasing the number of remotely controlled valves in the pipeline system.
Enhance understanding of asset health and life cycle cost for valves and valve actuators.</td></tr>
<tr><td>Meter Stations</td><td>7</td><td>Most meter stations associated with pipelines are 10 years old or less. Meter stations have a long life expectancy but can be vulnerable to obsolescence.
The Seckerton reservoir produces liquids from gas storage wells which enters the pipeline system, a combination of brine and oil that has consistently resulted in the fouling of straightening vanes and ultrasonic meter components.</td><td>Not maintaining meter stations poses the following risks:
Financial Risk: Unmitigated obsolescence or reduction in operational reliability of meter station assets will result in substantially increased maintenance costs due to parts price increases.
CSAT Risk: Extended lead times for parts could result in prolonged outage durations. During prolonged outages, gas supply cost to regulated customers will increase.</td><td>The maintenance strategy for meter stations is to:
Monitor parts availability and introduce generational changes in product lines.
Perform annual meter station inspections.</td><td>EGD’s replacement/renewal strategy for meter stations is to:
Reduce crude oil quantity or capture crude oil carryover at the Seckerton reservoir.
Continue to enhance understanding of asset health and life cycle cost for meter stations.</td></tr>
</table>

5.4.3.3 Reservoirs

ASSET SUBCLASS		AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Reservoirs	**Observation Wells**	40	Wells are inspected regularly through vertilog inspections. Well casings that exceed corrosion limits, as prescribed in *CSA Z341*, must be abandoned. With some exceptions, well casings are in good condition. 11 wells with microannulus leaks are being abandoned through 2017 and 2018. Crowland well design creates a situation where a single cement layer separates the inner casing from surrounding rock. The cement employed is unsuitable for sulphur-rich environments.	Not maintaining gas wells poses the following risks: *Safety Risk*: Loss of containment can pose a risk to public and worker safety. *Financial Risk*: Wells represent significant financial risk to EGD and regulated customers. Unexpected well failures carry a large replacement cost and incur product loss. *CSAT Risk*: Reduced reservoir performance may drive up gas supply costs.	The maintenance strategy for reservoirs is to: • Inspect casing internal condition (i.e., Storage Downhole Integrity Management Program) for evidence of any threat to pipe condition. • Perform vertilog inspections as prescribed by *CSA Z341*.	EGD's replacement/renewal strategy for gas wells is to: • Continue direct measurement of well condition for signs of corrosion. • Install A-1 observation wells to help validate the reservoir simulation models, verify the integrity of the reservoir boundaries, and demonstrate the relationship of low permeability zones to Lost and Unaccounted For Gas (LUF). • Periodically inject an acid solution to break down fines and precipitation of scale at the wellbore face (acidization). • Replace and install new and laneways and roads to provide adequate access to wells in compliance with *API 1171*. • Implement a Well Casings Program to address corrosion in the top two joints of the production casing. • Install new wells with associated gathering piping and temporary filtration to restore reservoir deliverability due to abandonment of older wells. • Reduce the number of Crowland wells constructed with cement unsuitable for a sulphur-rich environment and replace with new wells. • Install new reservoir observation wells to comply with *CSA Z341* requirements. • Purchase specialized well tools required to ensure reservoir personnel are equipped for continued well maintenance. • Continue to enhance understanding of asset health and life cycle cost for wells. • Follow practices on well abandonment due to corrosion as prescribed by *CSA Z341*. • Plan well replacements based on abandonment forecast and expected reduction in reservoir flow performance.
	Vertical Injection/ Withdrawal (I/W) Wells	42				
	Horizontal I/W Wells	10				
	Master Valves & Wellheads	33	Valve seal quality diminishes slightly with each actuation and is influenced by age, cycling frequency and amount of abrasive debris in the gas stream. With the exception of Crowland, the calendar age of master valves is relatively low (many less than 20 years old) and are believed to have good seal quality because of low cycle frequencies.	*Safety Risk*: Leaking master valves may not be able to provide effective isolation during emergency events or regular maintenance activities.	The maintenance strategy for master valves & wellheads is to: • Assess valve condition based on SMA input and direct measurement or observation. • Complete the Pipeline Valve Inspection Program.	EGD's replacement/renewal strategy is to replace master valves and wellheads when required. Currently, the Crowland facility is scheduled for planned replacement of master valves and wellheads.
	Emergency Shutoff Valves (ESV)	2	Valve seal quality diminishes slightly with each actuation and is influenced by age, cycling frequency and amount of abrasive debris in the gas stream. Most valves are less than five years old and are believed to have good seal quality because of low cycle frequencies. Currently, the greatest vulnerabilities of ESVs are failure to close due to freeze-off and failure to remain open due to loss of power.	ESVs provide fail safe isolation of the reservoir from surface facilities. Not maintaining ESVs pose the following risks: *Safety Risk*: Risk of injury to employees and the public during a well failure. *Financial Risk*: Risk of damage, repair costs and loss of stored gas. *CSAT Risk*: Risk of increased gas supply costs related to securing alternative gas supplies.	The maintenance strategy for master valves & wellheads is to: Put and direct measurement or observation. Complete valve maintenance program.	EGD's replacement/renewal strategy for emergency shutoff valves (ESV) is to: • Purchase a portable methanol injection system to mitigate freeze-ups experienced at the emergency shut-off valves. • Install electrical supply to existing ESVs that employ solar panels. • Continue the installation of ESVs for remaining horizontal wells.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT/ RENEWAL STRATEGY
Methane Emission Reductions	N/A	The Government of Canada is committed to reducing methane emissions from the oil and gas sector by 40-45% from 2012 level by 2025. In April 2018, Environment and Climate Change Canada (ECCC) published federal methane regulations to deliver on this commitment. The requirements target two key methane sources: fugitive emissions, which are unintentional leaks from equipment leaks, and venting emissions, which are intentional releases of methane into the air.	*Financial and CSAT Risk*: Failure to comply with the new methane emissions reduction regulations could result in orders to EGD, potentially limiting the use of compression equipment until compliance is achieved. Restricted use of compression equipment could reduce deliverability and trigger the need to secure gas from alternate sources, at additional gas supply cost.	N/A	EGD's replacement/renewal strategy for methane emissions reductions is as follows: • Upgrade compressor systems to minimize its environmental impact (such as methane emissions to the atmosphere). • Develop a leak detection program for gas storage facilities. • Continue to investigate rod packing emissions to determine appropriate mitigation measures. • Continue to investigate and remediate other potential sources of methane emissions to minimize facility venting. • Continue to understand the operational and asset requirements needed to adhere to the federal methane regulations.

5.4.4 Gas Compressors

Gas compressors facilitate the movement of gas to and from storage reservoirs, where the source pressure is too low to flow freely into the destination pipe network. Gas compressors are located at four compressor stations:

- Corunna Compressor Station (SCOR): 11 units
- Sombra Compressor Station (SSOM): 3 units
- Chatham D Compressor Station (SCHT): 1 unit
- Crowland Compressor Station (SCRW): 1 unit

SCOR compressor units produce 91.5% of the energy needed during an average annual inventory turnover (see **Table 5.4-4**), providing the greatest benefit to Storage operations, evidenced by its contribution to peak day flows requiring compression at the end of February. Note that initial condition modelling efforts in 2017 focused on only SCOR. Future condition modelling will include the remaining compressor stations.

Table 5.4-4: Station Significance Weighting

COMPRESSSOR STATION	TOTAL POWER	AVERAGE ANNUAL OPERATING HR/UNIT	STATION SIGNIFICANCE WEIGHTING FACTOR
SCOR	36750 HP	2000	91.5%
SSOM	3900 HP	1000	4.9%
SCHT	600 HP	4000	3.0%
SCRW	800 HP	650	0.6%

**Average Annual Operating Hours are approximate due to variances with weather severity. Chatham D Rated Engine Power is 1085 HP; however, the compressor rarely consumes more than 600 HP.*

All EGD gas compressors are natural gas-fueled, reciprocating compressors (in both integral and separable models). Integral compressors connect power cylinders and compressor cylinders to the same crankshaft (see **Figure 5.4-4**). Mass production of integral compressors ended in the early 1980s.

Modern gas compressors are separable with two crankshafts – one in the engine, one in the compressor frame – connected by a coupling. Separable compressors employ two distinct equipment elements that can be used with engines and compressors from different manufacturers.

Gas compressor assets are designed for continuous operation. Failures are influenced by service conditions (operating hours) and design life expectancy of its sub-systems. Some key sub-systems are wearable items, requiring regular inspection to establish wear tolerances and replace as needed.

SCOR uses integral compressors. SSOM, SCHT, and SCRW use separable compressors.

Gas compressors are repairable assets and are comprised of replaceable sub-assets:

- Foundations
- Crankshaft assemblies
- Engine assemblies
- Compressor assemblies
- Gas aftercoolers
- Heating and cooling systems
- Valve systems

Figure 5.4-4 depicts an example of an integral compressor sub-system:

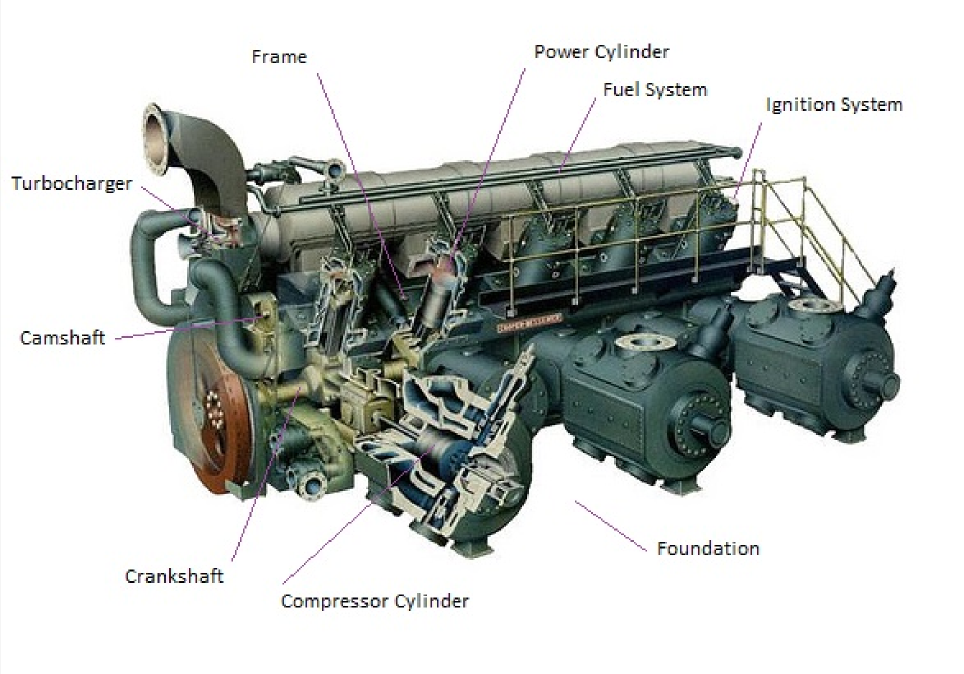


Figure 5.4-4: A Typical Integral Compressor Subsystem

Foundations: Foundations support the weight of a compressor (approximately 100 tonnes for an integral unit) and resist compressor dynamic forces. Foundation deterioration is normal, often a result of a combination of operating hours and contamination by leaking crankcase oil. Crankcase oil contamination increases with compressor unit age. Foundation deterioration results in crankshaft misalignment, increasing the potential for bearing and crankshaft failures.

Crankshaft Assemblies: A crankshaft assembly refers to the gas compressor crankshaft and its main bearings. Crankshafts are heavily influenced by cyclic loading, which can manifest as High Cycle Fatigue (HCF). HCF can result in total crankshaft failure, with the potential for uncontained collateral component failures. HCF cannot be determined through inspections - instead, crankshaft condition is estimated based on service history. Bearing failures and bent crankshafts were observed, and are considered a multiplier of fatigue cycles. Additionally, a cracked crankshaft has recently been found requiring immediate attention. This finding will be further investigated to improve the understanding of crankshaft asset health.

Engine Assemblies: Engine assemblies produce power for the gas compressor and include fuel systems, ignition systems, power cylinder liners, connecting rods, connecting rod bearings, pistons, cylinder heads, turbochargers, valve trains and engine frames. Common, less severe, problems encountered are: spark plug failures, nozzle leaks on the frame, fouled fuel valves. More severe engine problems requiring more extensive remediation include: pitting of power cylinder liners (due to coolant cavitation), malfunctions of engine power balancing systems, and misalignment of camshafts. Given the age of the units, many smaller sub-system components, like fuel train components, main water pumps, and glycol and lube oil auxiliary components (pumps, tanks, filters) experience obsolescence issues, where direct like-for-like replacement parts are no longer available. Catastrophic frame failures have not been encountered but minor nozzle leaks occur frequently due to vibration.

Compressor Assemblies: Compressor assemblies deliver power to the gas flow and include: connecting rod assemblies, packing glands, cross-head assemblies, pistons, unloading devices, compressor valves, and cylinder liners. These assets experience wear or degradation based on operating hours and the degradation rate is generally lower than engine assemblies. Common, less severe, problems encountered are: valve spring failures, unloader device failures, and packing gland leaks. More severe engine problems include: crosshead bushing failures, cylinder liner ovality or damage, and worn/damaged pistons, rings, and rider bands. Given the age of the units, many components, like packing glands, pistons, rings and rider bands are procured from non-OEM suppliers due to cost concerns.

Gas Aftercoolers: Gas aftercoolers are aerial coolers that use air fans to cool a tube bundle containing flowing gas downstream of the gas compressor. Historically, failures have occurred only on the fan drives as motor, bearing or fan belt failures. The tube bundles can internally corrode because they are made of thin-walled steel. Tube walls are difficult to inspect, only header boxes are inspected.

Heating and Cooling System: Heating and cooling systems are used to manage engine and compressor assembly temperatures. Heat from the central boiler system is applied to the gas compressor when turned off to ensure lube oil is sufficiently warm to start the unit. Cooling is applied by Jacket Water Coolers (JWC) when the unit is running to maintain safe material and fluid temperatures.

Valve Systems: Valve systems regulate and control gas flow within a compressor and include unit suction and discharge valves, a unit discharge relief valve, and unit mode valves. Typical problems shown in the maintenance history are related to valve actuator failures or freeze-offs. There is concern over the ability of the gas compressor valve to properly seal when in the closed position (known as bypass failures - leaks that do not escape to the atmosphere).

The calendar age for reciprocating compressors is shown in **Figure 5.4-5.**

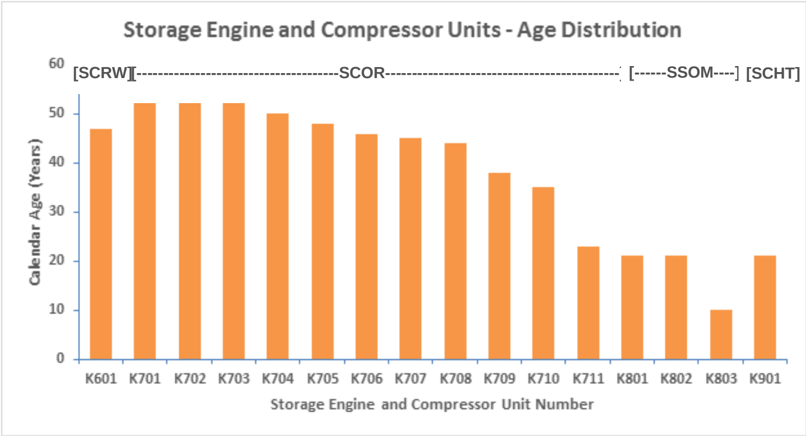


Figure 5.4-5: Calendar Age Distribution of Storage Engine and Compressor Units

The K601 gas compressor is located at the Crowland compressor station (SCRW). K801, K802 and K803 are located at Sombra (SSOM). K901 is located at Chatham D (SCHT). K701 to K711 are located at Corunna (SCOR).

5.4.4.1 Condition Methodology

A reliability assessment was conducted on all SCOR compressors combined with a multiplier-based apparent condition modelling approach to determine asset condition. A recurrent data analysis was performed using statistical modelling to determine the relationship between failure frequency and gas compressor operating hours. SMAs were then consulted to define and quantify the effect of failure-influencing factors. A condition status was assigned to seven key gas compressor sub-assets, based on a conditional reliability metric (at least one sub-asset failure will occur within a 2000-hour mission time).

As it relates to Storage assets, condition refers to the ability of an asset to reliably and cost-effectively perform its intended function, which can include achieving the performance expectation for which it was designed, or providing adequate process safety measures. Gas compressors are repairable assets – they are not in a steadily deteriorating state, and improving their condition improves reliability.

Gas compressor condition is described through the Asset Health Index in **Table 5.4-5**.

Table 5.4-5: Health Index System for Gas Compressors

HEALTH INDEX	DESCRIPTION
SHI1	Failure in > 10,000hrs
SHI2	Failure in 5,000hrs to 10,000hrs
SHI3	Failure in 3,000hrs to 5,000hrs
SHI4	Failure in 2,200hrs to 3,000hrs
SHI5	Failure in ≤ 2,200hrs

The reliability modelling analysis used historical maintenance data collected from Maximo and was performed for 11 SCOR compressor units (K701 thru K711). For completeness, reliability relationships established for SCOR compressors were applied to K601, K801, K802, K803 and K901 using adjustment factors. New reliability relationship information is needed for separable compressors. However, condition findings are expected to be directionally informative at this time.

After completing the reliability analysis, influencing factors were applied to the resultant correlations. Influencing factors employed in the condition model are described in **Table 5.4-6**:

Table 5.4-6: Failure Factors for Storage Compressor Asset Subclasses

COMPRESSOR COMPONENT	CRITERIA	COMMENTS
Foundation	Previous frame alignment work orders	Frame misalignment is a leading indicator of foundation degradation.
	Previous repairs	Foundations with previous repairs are more susceptible to failure.
	Damages	Refers to damage detected during visual inspection.
Crank Assembly	Previous crankshaft repairs	Bent crankshafts that were previously repaired are more susceptible to failure.
	Compressors with frequent starts and stops are more susceptible to crank failures.	Frequent compressor starts and stops result in additional wear and tear on crank assemblies, especially as it relates to bearings.
	Compressor torque/load exceeds its recommended rating.	Over-rated load/torque will apply extra stress on the crankshaft and make it more susceptible to misalignment.

Foundations: Foundations are visually inspected to assess foundation cracks. Cracks normally occur at a location and depth that aligns with the positioning of anchor bolts. Oil leaking from cracks is an indicator of poor foundation condition.

Crankshaft Assemblies: Research suggests that crankshafts exhibit failures increasing after 300,000 operating hours. Industry practices point to proactive crankshaft replacement (typically between 125,000 and 150,000 operating hours). Bent crankshafts and bearing failure frequency are indicators (failure multipliers) that cycles have increased at a rate beyond nominal.

Engine Assemblies: Engine assembly condition is managed through a preventative maintenance program (i.e., regular mechanical inspections and overhauls). Engine assembly failures occur more frequently than foundation and crankshaft assembly failures, posing significant risk at critical times of the Annual Turnover cycle. Reliability data has been collected for a wide range of failure types.

Compressor Assemblies: Compressor assembly condition is also managed through a preventative maintenance program similar to engine assemblies. Compressor assembly failures occur more frequently than foundation and crankshaft assembly failures, posing significant risk at critical times of the annual turnover cycle. Reliability data has been collected for a wide range of failure types.

Gas Aftercoolers: Gas aftercooler operation is crucial during high end injection and low end withdrawal. The current health assessment of gas aftercoolers has been determined using reliability data associated with fan drive failures. Condition assessment of pressure containment components will be incorporated into future health modeling for this asset.

Heating and Cooling System: Heating systems are necessary to ensure unit startability. Cooling systems are necessary to provide cooling during gas compressor operation. Typical problems encountered with these systems include JWC fan drive failures and glycol leaks from flanged and threaded connections. Failures are frequent, but are short in duration. The current health assessment of heating and cooling system has been determined using reliability data associated with fan drive failures. Condition assessment of pressure containment components will be incorporated into future health modeling for these assets.

Valve Systems: Valve systems are critical to group compressors - it supports movement of gas in up to five different streams from storage reservoirs. Typical problems are related to valve actuator failures, freeze-offs and valve seal quality. The current health assessment of valve systems has been determined using reliability data associated with actuator failures and freeze-offs. Condition assessment of valve seal quality will be incorporated into future health modeling of this asset.

In addition to modelling the condition of gas compressors, hazard and operability studies (HAZOP) will be conducted to advance the understanding of the health associated with valve systems.

5.4.4.2 Condition Findings

Application of the gas compressor condition modeling methodology and physical inspection yield the results in **Table 5.4-7**.

Table 5.4-7: Gas Storage Asset Health Index (over a 2000 –hour mission time)

	Unit Number	Current Run Hours as of 1/1/2017	Assumed Annual Run Hours	Foundation[9]	Crankshaft Assembly	Engine Assembly	Compressor Assembly	After Cooler	Heating & Cooling System	Valve System
SCOR	K701	88605	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K702	78931	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K703	81088	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K704	114316	2000	SHI3 (3000-5000hrs)	SHI1 (>10000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K705	98212	2000	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)[10]	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K706	86257	2000	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K707	95508	2000	SHI3 (3000-5000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K708	103711	2000	SHI4 (2200-3000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
	K709	33753	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI3 (3000-5000hrs)	SHI5 (<=2200hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)
	K710	34900	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI3 (3000-5000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)
	K711	69800	2000	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)
SCRW	K601*	27912	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI4 (2200-3000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)
SSOM	K801*	30312	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI4 (2200-3000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)
	K802*	31615	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI4 (2200-3000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)
	K803*	5075	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI3 (3000-5000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI2 (5000-10000hrs)
SCHT	K901*	59548	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)

[9] Foundation condition has been updated to incorporate the results of a recent physical inspection.
[10] Due to the timing of occurrence, the asset health results do not reflect the recently cracked crankshaft at K705, but will be incorporated into future asset health assessments.
The condition analysis for K601, K801, K802, K803 and K901 is under development, however the condition analysis associated with the 11 units at SCOR have been applied as preliminary.

Foundations

SCOR: Foundation replacements were recently conducted at K705 and K706. K704, K707, and K708 exhibit poor foundation condition. Visual foundation inspections, annual bearing clearance, and web deflection inspections confirm that these units have noticeable foundation degradation.

SSOM, SCHT, and **SCRW**: Condition findings are extrapolated from condition and operating hour relationships determined for SCOR. Findings are informative only. SSOM, SCHT, and SCRW employ separable compressors only and have relatively low operating hours.

Crankshaft Assemblies

SCOR: Currently, five compressor units (K704 thru K708) are expected to exceed the 125,000 operating hour limit within 10 years. None are expected to exceed 300,000 operating hours (the industry-recognized operating limit) within the next 10 years.

Four compressor units have experienced bent crankshafts (K702, K703, K706 and K711) and two units (K709 and K710) experience high bearing failure frequency attributed mainly to the large compressor cylinder bore. One unit (K705) recently experienced a cracked crankshaft, and an immediate investigation led to its replacement.

Condition modelling results show most crankshaft assemblies will experience a nominal failure probability, with the exception of K706 and K711. Failure probabilities for K706 and K711 are influenced by recently bent crankshafts. Although not reflective in the latest asset health report due to timing, the learnings from the recent cracked crankshaft on K705 will be incorporated into future asset health assessments.

SSOM, SCHT, and **SCRW**: Condition findings are extrapolated from condition and operating hour relationships determined for SCOR. Findings are informative only. SSOM, SCHT, and SCRW employ separable compressors only and have relatively low operating hours.

Engine Assemblies

SCOR: Engine assemblies show a wide variability in condition. Most failures are short in duration, except for K701, K702, and K703, which have experienced long duration outages in the last five years related to lean burn system conversions, which have shown poor reliability. Condition status considers the last time that an engine overhaul has been performed. Based on manufacturer-recommended overhaul intervals, condition values range from SHI3 (failure in 3,000hrs to 5,000hrs) to SHI5 (failure in ≤ 2,200hrs) as regular overhauls occur in 10-year intervals.

SSOM, SCHT, and **SCRW**: Condition findings are extrapolated from condition and operating hour relationships determined for SCOR. Findings are informative only. SSOM, SCHT, and SCRW have relatively low operating hours.

Engine problems requiring extensive remediation include: pitting of power cylinder liners (due to coolant cavitation), malfunctions of engine power balancing systems, and misalignment of camshafts. Other identified issues are: spark plug failures, nozzle leaks on the frame, and fouled fuel valves. Given the age of the units, many smaller sub-system components, like fuel train components, main water pumps, and glycol and lube oil auxiliary components (pumps, tanks, and filters) are obsolete. No catastrophic frame failures have occurred, but minor nozzle leaks occur frequently due to vibration.

Compressor Assemblies

SCOR: Compressor assemblies show a wide variability in condition. Most failures are low impact (i.e., short duration) outages. Condition status considers the last time that an engine overhaul has been performed. Based on manufacturer-recommended overhaul intervals, condition values range from SHI4 (failure in 2200 to 3000 hours) to SHI5 (failure in ≤ 2,200 hours) as regular overhauls occur in 10-year intervals.

SSOM, SCHT, and **SCRW**: Condition findings are extrapolated from condition and operating hour relationships determined for SCOR. Findings are informative only. SSOM, SCHT, and SCRW have relatively low operating hours.

Problems requiring extensive remediation include: crosshead bushing failures, cylinder liner ovality or damage, and worn/damaged pistons, rings, and rider bands. Other identified issues are: valve spring failures, unloader device failures, packing gland leaks. Given the age of the units, many components, like packing glands, pistons, rings and rider bands are procured from third-party suppliers due to cost concerns.

Gas Aftercoolers (GAC)

Most gas aftercooler failures are due to fan drive failures. All coolers (except K704) are equipped with the original GAC supplied at installation. All GAC units were retrofitted recently with new fan drives to reduce ambient noise. Fan drives at SCRW (K601) have been recently replaced to mitigate noise.

Heating and Cooling System

Reliability data has identified glycol leaks as a failure mode for engine heating systems. Failure data relates mainly to glycol leaks and fan drive failures in JWCs. Cooling fan failures occur with fairly high frequencies, resulting in a condition value of SHI3 or greater.

Valve Systems

SCOR: Valve system condition status refers mainly to valve actuators. Valve actuator failure occurs in fairly high frequencies, resulting in an assessed condition value greater than SHI2 (failure in 5,000 to 10,000 hours).

A study of the effectiveness of unit discharge pressure relief valves (PSV) was completed, finding that all discharge PSVs were installed under legacy design standards with a set pressure of 110% of the MOP and in some cases with inadequate flow capacity.

SSOM, SCHT: Condition findings are extrapolated from condition and operating hour relationships determined for SCOR. Findings are informative only. SMA input suggests that valve systems are sustainable and in good working order, with the exception of valve actuators due to obsolescence.

SCRW: Condition findings are extrapolated from condition and operating hour relationships determined for SCOR. Findings are informative only. SCRW is almost 50 years old with an expectation that valve systems are likely to exhibit condition concerns. In addition, SCRW unit valve configuration is a process safety concern because valves are manually actuated with no loading valve. Manually actuated valves do not accommodate automatic ESD strategies.

Mean Time Between Failures

SCOR: Reliability data for all SCOR compressors has been transformed into a Mean Time Between Failure (MTBF) representation. The disparity of unit reliability among SCOR compressor units is significant, as shown in **Figure 5.4-6**.

Recent engine assembly failures on K701, K702, and K703 have resulted in greater failure severity (greater repair cost and longer outage durations) than engine assembly failures on other SCOR gas compressors, owing to a less robust mechanical design, and becoming more pronounced due to recently installed emissions controls. Continued reliance on these units is not considered sustainable, and replacement should be considered to avoid disproportionately high maintenance cost and unpredictable unit availability.

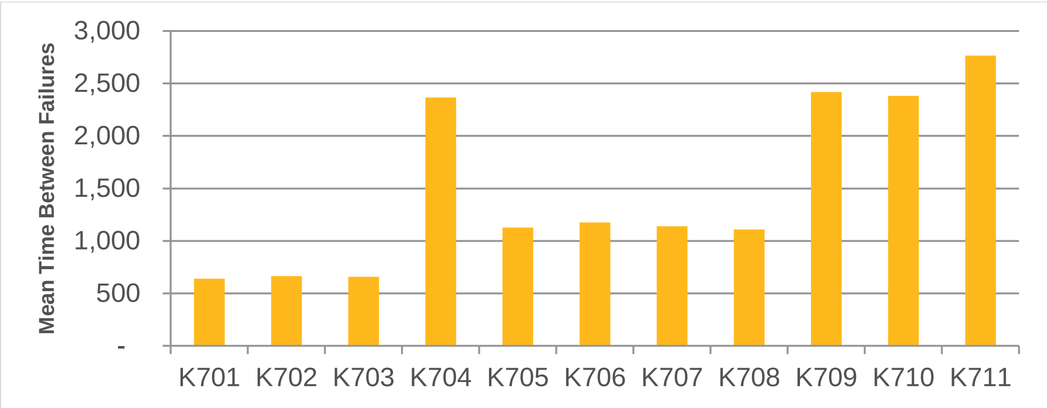


Figure 5.4-6: Unit Reliability Comparison for SCOR Compressor Station

K705 to K708 engine assemblies exhibit distinctly lower reliability due to deteriorated foundations (currently being replaced). Once replaced, they are expected to exhibit similar engine assembly reliability to K704, K709, K710 and K711.

K701, K702, and K703 engine assemblies fail at a frequency 3.8 times greater than units K704, K709, K710 and K711. Foundation condition for K701, K702, and K703 is at SHI1 (failure in > 10,000hrs), indicating that foundation condition does not explain low engine assembly reliability.

SSOM, SCHT, and **SCRW**: MTBF data is not yet available for these compressor stations. Asset condition, especially at SCRW, is considered to be poor by SMAs. In addition, SCRW has been identified as requiring additional noise mitigation measures.

5.4.4.3 Risk and Opportunity

Gas compressor failures can pose a significant customer satisfaction risk as approximately 25% of annual gas volume and 55% of peak flow rate delivered into the EGD gas distribution system is from EGD Storage facilities. The consequence of compressor failures is dominated by safety and the gas cost impact to customers. Customer satisfaction risk associated with a repairable failure of a single compressor is influenced by the time of year and weather severity. Safety risks tend to be steady throughout the annual turnover cycle.

Safety Risk: Safety risk related to loss of containment from the compressor units is considered. However, the chance of a significant leak is low, and safety systems (e.g., gas detection, flame detection, emergency shutdown) reduce the chance of an escalation (i.e., fire, explosion) even further. Proximity of station personnel to gas compressor units and the probability of an uncontained failure were also considered in the QRA.

- Compression has a minor influence on public safety risk, but a more direct influence on safety risk to employees. Except for SCRW, public risk is mitigated by the agricultural location of compressors. A HAZOP at SCRW will be conducted. Recommendations of the SCRW HAZOP will be used to inform QRAs.
- Reciprocating compressors employ positive displacement compression processes, which can create process safety situations if valves become out of position. Associated risks are mitigated by process design, procedures, and formal operator qualification and training.

Financial Risk: Financial risk is significantly mitigated by regular inspection of the units, which then inform the necessary preventative maintenance work. A preventative maintenance program mitigates financial risk by reducing the chance of unexpected failures.

- Reciprocating compressor failures (unplanned outages) result in unexpected repair costs (both materials and labour) and frequently involves collateral damage. The likelihood for a compressor failure to cause an event affecting non-company property and experience commodity loss is low due to mitigations within a compressor building (i.e., gas/flame detection and ESD systems).

Customer Satisfaction Risk: The operational reliability of the gas compressors is integral to managing customer satisfaction risk. Unplanned failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs.

Gas compressor reliability risk changes continuously during annual inventory turnover. At early injection or withdrawal, compression is not required at all times to meet nominations. Power requirements increase steadily and reach a maximum during late injection or late withdrawal. Some compression power is required at mid-season injection or withdrawal. Reliability risk peaks in September, October, and March. Starting at the end of February, all gas compressors, minus a partial Loss of Critical Unit, are required to meet peak day deliverability. There is a reduced probability, in months other than September, October and March, that a single, repairable compressor failure will yield a significant consequence. Statistical consideration of cyclic compressor criticality is incorporated in the risk model.

Compressor reliability risk is at its maximum during a cold winter. Weather variability reduces the probability that a single, repairable compressor failure will occur and yield significant consequences. Weather data has been analyzed to determine the probability of experiencing a worse than expected winter.

Consequences escalate for concurrent compressor failures. Concurrent compressor failures occur when there is a high reliance on compression with low reliability, or when a single auxiliary system failure affects multiple units. Reliability assessments were performed for all SCOR compressor units. Probabilities of concurrent compressor failures have been generally considered in the risk model, which recognizes conditions that lack redundancy. Assessment results show overall reliability of K701, K702 and K703 gas compressors is dramatically lower than other SCOR units and is likely to worsen as manufacturer support for legacy equipment continues to decline.

- Unplanned compressor failures can produce minor increases in methane emissions to the atmosphere. New federal GHG emission regulations are anticipated to impose new restrictions on methane vented to atmosphere at a compressor station. Regulations are currently anticipated to impose these restrictions on Storage facilities.
- A compressor failure would not normally result in environmental rehabilitation. Lost fluids within the compressor building would normally be contained onsite. The exception to this statement is a glycol leak from the compressor cooling system (i.e., JWCs). JWCs could potentially leak into the site drainage system.

- Individually, each reciprocating compressor asset creates a moderate operational reliability risk. Short duration compressor outages are managed by securing gas from alternative sources at higher prices. The longer the outage, the greater the direct cost to customers. Long term outages of multiple compressors during a harsh winter can incur higher costs to customers because of the inability to meet storage nominations and the resulting need to purchase gas at less favourable market conditions. Short duration outages can happen regularly, however long term outages are much less frequent.

5.4.4.4 Strategy

The strategy for gas compressors is to address reliability risks associated with the gas compressor assets at SCOR.

SCOR:

- Implement a foundation block remediation program to replace foundation assets in poor condition.
- Overhaul compressor and engine assemblies to address asset wear-out.
- Conduct an analysis to assess options (including gas supply alternatives) to improve compressor reliability for K701, K702, and K703 and commence a FEED study on the selected option.

Compressor maintenance program activities:

- Continue to perform preventative maintenance of compressor equipment as prescribed by the manufacturer.
- Proactively replace sub-asset components that are in poor condition and cannot be overhauled.
- Proactively replace obsolete gas compression systems/devices.
- Continue to upgrade existing units to minimize air emissions to atmosphere.
- Implement a program to replace recycle bypass valves with automated control valves and instrumentation.
- Proactively replace aging JWCs to address internal corrosion of cooling tubes.
- Install a glycol-to-glycol heat exchanger to accommodate separation of compressor unit coolant from the general plant heating system.
- Proactively upgrade compression systems with new technology to improve reliability, safety and reduce operating costs.

SSOM: Minor compressor and engine assembly overhaul planned based on manufacturer recommendations.

SCHT: No planned replacement/renewal activities.

SCRW:

- Complete a HAZOP to understand the risks associated with this facility.
- Conduct an analysis to assess mitigation options required.
- Implement noise mitigation measures to be in compliance with environmental regulations.
- Evaluate the benefits associated with SCRW and how this facility contributes to the gas supply plan and storage reliability.

In addition to the location-specific initiatives, there is a program to remediate any findings as a result of FIMP inspections. EGD continues to enhance its understanding of asset health and life cycle cost for compression facilities, which will inform future capital investment requirements.

5.4.5 Yard Process Pipe

Yard process piping transfers gas through a compressor station yard to and from storage reservoirs and is comprised of pipe and fittings (excludes valves, pressure vessels, atmospheric tanks, etc.).

Yard process pipe age ranges from eight to 55 years old. Yard process piping can be above- or below-grade; typically older piping is above-grade and newer piping is buried. Piping older than 40 years of age have low notch toughness characteristics and unavailable material composition data, increasing the potential consequences of a failure. Some piping is undersized, leading to high flow velocities and flow-induced vibration, increasing the probability of a failure. All yard process pipe is designed to 50% SMYS, and pipe MOPs vary from 6205 kPa (900 psig), 8273 kPa (1200 psig) and 10687 kPa (1550 psig). Pipe with varying MOPs are interconnected, especially in older compressor stations where operating pressures for newer reservoirs (i.e., requiring high MOPs) have been designed to work in conjunction with older piping systems (i.e., designed to lower MOPs). A HAZOP will be used to evaluate the effectiveness of over-pressure protection.

Yard process piping is protected by a central ESD system. In all cases, an ESD can be activated whereby all compressor station yard piping is vented to the atmosphere. In addition, yard process piping is protected by a rectified cathodic protection system, within the bounds of a compressor station. Yard process piping can be found at all four storage compressor stations.

5.4.5.1 Condition Methodology

Yard process pipe is exposed to several factors affecting condition:

- **Direct (measureable) threats**: Internal corrosion, external corrosion, thermal stresses caused by variability in gas temperatures, and vibration caused by compressors or excess flow conditions. Storage compression can create large thermal gradients in yard process piping, which can subsequently create large additional pipe stresses and increase the probability of failure. Typically, these thermal gradients experience a maximum during injection (summer) when ambient temperatures are high.
- **Indirect threats**: effectiveness of pressure control systems, over-pressure protection systems, and flow-induced vibration.

The FIMP has undertaken condition measurement activities to evaluate wall loss on yard process pipe. FIMP activities have focused on yard process pipe in SCOR only, given its relative significance to the Storage operation.

Current FIMP activities include a wall thickness survey of all above-grade headers as SCOR. Continued effort in this area is expected to provide actionable yard piping condition information.

A full HAZOP will also be performed for the SCOR yard process piping system to highlight areas of reduced process safety effectiveness. Future HAZOPs are planned for SCRW.

5.4.5.2 Condition Findings

Previous targeted inspection of SCOR yard headers, conducted in 2007 using automated ultrasonic measurements, suggest that internal corrosion threats at SCOR are currently low. The FIMP is expected to provide a more detailed assessment of internal/external corrosion and signs of thermal growth or vibration-induced cracking. HAZOPs will be conducted to evaluate the effectiveness of pressure control and over-pressure protection systems. Yard process pipe at SSOM and SCHT are newer and are expected to be in better condition than the pipe at SCOR. Also, yard process pipe at SCRW is expected to be in better condition than SCOR pipe.

The metering area at SCOR is overly complex for its current use. It was originally designed to measure pool inventory, which has been replaced by inventory management meters located at the reservoirs. The existing configuration includes vintage piping with unknown material characteristics and unnecessary piping elements (e.g., flanges, valves) for its current function.

In addition, higher pipe velocities have been experienced during late season withdrawal and Operations has observed higher than anticipated pipe vibrations at the existing cross flow header at SCOR. Vibration analysis is underway to understand the link between flow velocity and vibration severity that can lead to high cycle fatigue.

5.4.5.3 Risk and Opportunity

The consequence of yard piping failures is dominated by the gas cost impact to customers and safety. EGD’s customer satisfaction risk due to a repairable failure of yard piping is diminished by the time of year and weather severity. Safety risks tend to be steady throughout the annual turnover cycle.

Safety Risk:

- Process safety risks are generally related to the legacy design standards of the older compressor stations and the evolution of station piping systems since 1964. Generally, these risks are not expected to increase over time; they are simply being recognized through the risk assessment process. Process safety risks affecting yard process pipe include over-pressure protection of pipe, corrosion, and damage from stresses created by thermal cycling, which can result in loss of containment.
- Yard process pipe condition has a minor influence on public safety risk, but a more direct influence on safety risk to employees. Public risk is mitigated by the agricultural location of yard piping. However, loss of containment has the potential to injure workers if asset condition is allowed to degrade, causing leaks and creating flammable mixtures. Yard process pipe is typically designed for 50% SMYS and the oldest piping systems possess some undesirable material qualities, posing serious consequences.

Industry data suggests that major loss of containment events are rare (unlikely to happen during the life of the facility). However, consequences will be severe.

Financial Risk: Damages to neighbouring businesses, residences, agricultural operations and company property were considered in risk assessments. Consequences were evaluated using the proximity of affected assets due to a loss of containment event and applying accepted probabilities. Risk of commodity loss was considered using expected response time to isolate and expected pipe pressure, combined with industry-accepted probability of failure values.

- Yard piping failures have potential to damage non-company infrastructure and can incur significant commodity loss. A yard piping failure can cause a large event affecting non-company property within the Potential Impact Radius (PIR) of a compressor station and commodity loss. There could be damages to agricultural operations, residences, and businesses near the compressor station, and electrical transmission corridors.
- Yard piping failures have the potential for moderate commodity loss. Fail Closed Emergency Shutdown valves mitigate this risk by ensuring that affected sections of pipe can be isolated during a loss of containment event.
- Yard piping failures can cause significant damages to company facilities, including compression. Given the age of the compression equipment, repairs may not be possible.

Customer Satisfaction Risk: A large component of customer satisfaction risk is related to the integrity of yard process piping. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single process pipe failure can shut down an entire compressor station for a long duration.

- Yard piping failures can produce moderate increases in methane emissions to the atmosphere. The extent of an uncontrolled release can be mitigated by initiating a plant-wide ESD which closes all plot edge valves and vents all process piping.
- Failure of yard process pipe can result in loss of Storage deliverability, hence reduced operational reliability. A loss of containment will require an immediate shutdown of Storage operations, evaluation of any damage, and development and execution of a business resumption plan. Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost.

5.4.5.4 Strategy

The current strategy is to perform an assessment of the cross-flow header system to understand the extent and impact of the experienced vibration. The mitigation option being investigated is to replace the above-grade cross-flow header system and process piping at SCOR. A FEED study is currently underway to further evaluate design options.

In addition, FIMP and HAZOP assessments will continue to be completed across all compressor stations, including yard process piping components. If emerging risks are identified from FIMP inspections and/or HAZOP assessments, the appropriate mitigation measures will be planned.

5.4.6 Yard Auxiliary Systems

Yard auxiliary systems refers to all piping elements: pipe, fittings, valves, regulators, boilers, pumps, air compressors, etc. as they relate to systems like fuel gas, low point drains, atmospheric vents, compressed air, glycol supply/return, power gas, lube oil supply, oily water, potable water, maintenance flares and fire water. Yard auxiliary systems range from 20-55 years old. Auxiliary piping tends to be smaller diameter (less than or equal to NPS8) with much lower SMYS.

5.4.6.1 Condition Methodology

Yard auxiliary systems are exposed to several factors that affect condition:

- **Direct (measureable) threats**: Internal corrosion, external corrosion, thermal stresses caused by variability of gas temperatures, and vibration caused by compressors.
- **Indirect threats**: Effectiveness of pressure control systems, over-pressure protection systems, and obsolescence of actuators and pumps.

The condition of yard auxiliary systems is determined using the experience and recommendations of SMAs and is assessed as follows:

- **Rotating equipment (pumps, air compressors)**: Preventative maintenance inspections as prescribed by the manufacturer.
- **Piping, pipe components (fittings, valves, filters), and other yard auxiliary elements**: There is no formal proactive inspection program for auxiliary piping. SMA input is used to determine condition on an opportunistic basis.

5.4.6.2 Condition Findings

The following condition findings have been identified for yard auxiliary assets:

- Obsolete components were found primarily at SCOR.
- The air compressor at SCHT is too small, approaching end-of-life, and is located inside the compressor building.
- Maintenance is required for start air compressors.
- Existing fire suppression system does not employ hydrants to suppress fire.
- Existing SCOR flare system does not provide any metering or liquids knockout, and has process safety concerns.

Based on opportunistic pipe condition inspections during tie-in work, it has been found that the pipe is generally in good condition due to the asset's small diameter and heavy wall thicknesses, and adequate cathodic protection systems.

5.4.6.3 Risk and Opportunity

Yard auxiliary piping systems supplies gas compressors with the fluids it needs to operate - a significant failure can affect multiple gas compressor units. Condition-related risks were determined as low by SMAs. The consequence of yard auxiliary system failures is dominated by the gas cost impact to customers. Customer satisfaction risk associated with controls and communications failure is diminished by the time of year and weather. Safety risks tend to be steady throughout the annual turnover cycle.

Safety Risk: Enhancement of process safety is considered in risks assessments using standard risk assessment tools.

- Yard auxiliary system condition has a direct influence on safety risk to workers. Loss of containment causing leaks and creating flammable mixtures has the potential to injure workers.
- Process safety risks affecting yard auxiliary systems include: over-pressure protection of pipe, corrosion, and damage from stresses created by thermal cycling which can result in loss of containment.

Financial Risk: Based on the nature of the asset, financial risks tend to be low. Assets are low pressure and small in diameter so failures will have low consequence for damages or commodity loss.

- Yard auxiliary system failures have limited potential to damage non-company infrastructure or incur significant commodity loss, due to small pipe size and lower operating pressures. Yard auxiliary system failures can cause moderate damages to company facilities.

Customer Satisfaction Risk: Small assets associated with yard auxiliary systems can contribute to customer satisfaction risk – these are single systems shared by many gas compressors, with some level of redundancy. Yard auxiliary systems can have a large consequence, under certain conditions.

- New customer satisfaction risks have been identified related to anticipated additional environmental regulations. Enhancements to yard auxiliary systems are anticipated in advance of federal methane emissions regulations. The scope and scale of required yard auxiliary piping enhancements continues to evolve.
- Yard auxiliary system failures can produce moderate methane emissions to the atmosphere, due to small pipe size and often lower pressures.
- Failure of yard auxiliary systems can result in loss of Storage deliverability, hence reduced operational reliability. Loss of deliverability would trigger the need to secure gas from alternate sources. A loss of containment would require an immediate shutdown of Storage operations, evaluation of any damage, and development and execution of a business resumption plan. An unignited loss of containment, with minimal pipe damage could be a limited duration event of several days. An ignited loss of containment could be a longer event (possibly several weeks or months) because it has greater potential for collateral damage.

5.4.6.4 Strategy

Minor yard auxiliary system replacements are anticipated, mostly related to process safety enhancements:

- Proactively replace obsolete yard auxiliary system components (part of general maintenance program).
- Overhaul start air compressors at SCOR to replace normal wear components (bearings, rings, seals, valves).
- Upgrade the existing air compressor at SCHT to replace the current obsolete and undersized unit.
- Upgrade and expand the existing on-site firewater protection system.
- Design and install a knock out drum and metering system for the existing maintenance flare.

5.4.7 Yard Valves and Actuators

Yard valves and actuators direct the flow of gas through a compressor station yard and to and from storage reservoirs. The scope of the yard valves and actuator sub-asset group is limited to NPS4 valves and larger, and are distinct from the valve systems identified in **Section 5.4.4**. Yard valves and actuators are used for several purposes:

- **Process flow mode configuration**: Directs flow to/from reservoirs at different pressure and flow conditions.
- **Over-pressure protection**: Prevents over-pressure conditions and possible loss of containment.
- **Plot edge configuration**: Acts as primary isolation point to shut in a compressor station during an upset condition.

Figure 5.4-7 shows yard valve quantity versus calendar age. Valve inventory includes NPS4 and large yard valves at SCOR, SSOM and SCHT. SCRW yard valves are not yet entered in Maximo and are not included in the distribution below. The valve quantity at SCRW amounts to 10 units with an average age of 48 years.

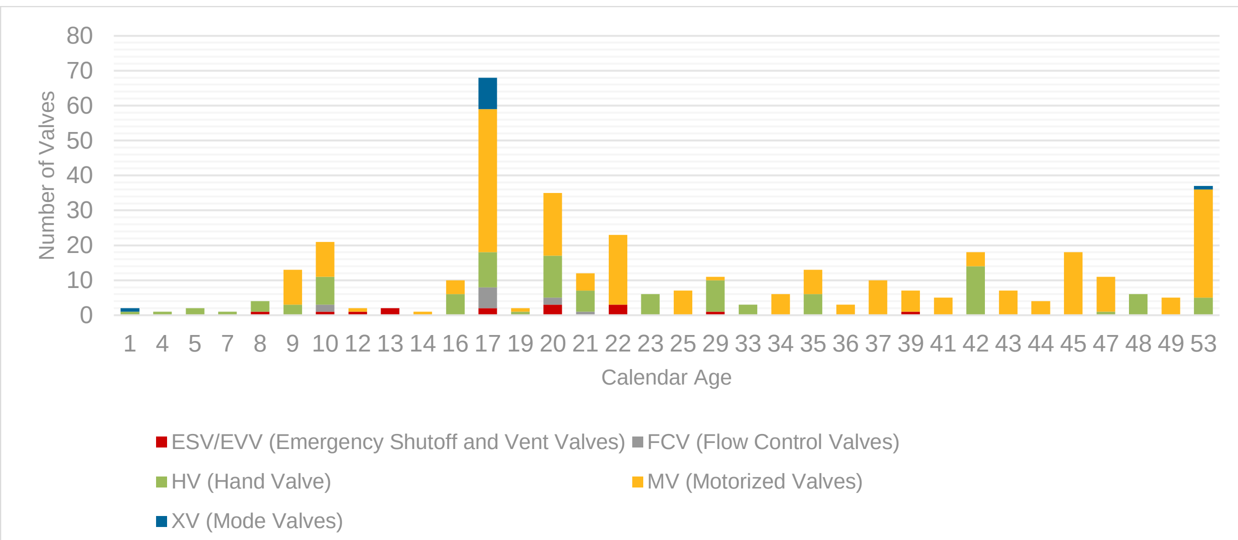


Figure 5.4-7: Station Valve Calendar Age Distribution

5.4.7.1 Condition Methodology

Yard valves actuators are exposed to several factors that affect condition:

- Failure to operate
- Leaks to the atmosphere
- Failure to properly seal when in the closed position (bypass failure)

SMAs have identified several failure factors that can potentially contribute to accelerated degradation of these assets: size, pressure difference, and location (above/underground).

Yard Valves: Of the different failure types, the most significant is bypass failure. Storage Operations is investigating quantitative methods to assess valves for bypass failure. The most promising approach to date is to perform tests using a valve's body bleed. Valve service providers are also being approached for solutions. Once an approach is established, Operations personnel will be tasked with regular inspection of valves for bypass failure. Condition information is expected to be available by 2020.

Yard Valve Actuators: The condition of yard valve actuators is determined through SMA input as well as available data extracted from Maximo.

5.4.7.2 Condition Findings

Yard Valves: Yard valve condition is generally thought to be poor, due, to brine, reservoir particulate/debris, and high operating frequency. Storage Engineering has initiated a ranked valve replacement list based on bypass failures. Seal quality of many yard valves is known to be poor, because many have a long service history. Valve seal quality cannot be compared with valves in other asset classes because operating conditions are unique - yard valves at Storage can see high differential pressures, crude oil, brine and reservoir particulate, and run on a high operating frequency. These factors influence valve seal quality to varying degrees. If a valve does not seal when closed, then a loss of containment within the yard process pipe may not be controllable, thereby compromising process safety. Findings based on SMA input indicate that yard valve seals at SCOR are in very poor condition. Valve seals at SCRW, SCHT and SSOM are better, because valves are newer or used less frequently. Bypass failures have occurred on newer valves in cases where there is a high frequency of operation and/or seal damage/wear from pipe debris.

Condition status of yard valve seal condition was estimated through SMAs. This is an interim measure until more quantitative information is available through a structured inspection program.

Yard Valve Actuators:

SCOR: Actuators at SCOR was determined by SMAs to be very good.

SSOM: Actuators at SSOM are becoming obsolete, making their condition poor.

SCHT: Actuators at SCHT are in poor condition and require upgrading.

SCRW: Actuators at SCRW are primarily manual, making their condition very good.

5.4.7.3 Risk and Opportunity

Condition related risks are evaluated to be moderate by SMAs. The consequence of yard valve and actuator failures is dominated by the gas cost impact to customers. Customer satisfaction risk associated with yard valve and actuator failure is diminished by the time of year and weather severity when the failure occurs. Safety risks tend to be steady throughout the annual turnover cycle.

Regular inspection and testing helps to reduce risk of unexpected failure of assets significantly. For example, actuators can be tested at regular intervals to ensure they are operational, reducing the chance of failure in an emergency situation. Yard valve seals can be indirectly tested using the valve body bleed. Regular inspection will allow for proactively identifying and replacing valves that are not sealing properly before a significant safety hazard arises.

Safety Risk: Safety risks, including process safety, are expected to be better defined after completion of HAZOPs and integrity inspections. Process safety risks are generally related to the effectiveness of a valve's ability to isolate during an ESD, provide over-pressure protection, or isolate during maintenance work. In some cases, over-pressure protection may need enhancement. Generally, these risks are expected to increase over time, as valves experience wear. Replacement of fail closed valves is expected to be driven by regulatory compliance related to the ESD system, combined within an internal measure to define unacceptable leakage rates.

- Yard valve and actuator condition has a direct influence on safety risk to the public and employees. Typically, yard valves are full port ball valves with soft seals that are vulnerable to wear. Inadequate gas containment by valves caused by actuator failure or seal failure during an emergency situation has the potential to injure the public and workers. Leaking yard valves can also compromise worker safety during maintenance operations by unintentionally exposing workers to the risks of asphyxiation, fire, and mechanical energy release.
- Process Safety risks affecting yard valves and actuators include over-pressure protection of pipe due to leaking valves, and reduced reliability resulting from valves being out of position.

Financial Risk: Damages to neighbouring businesses, residences, agricultural operations and company property have been considered in risk assessments. Consequences are evaluated using proximity of affected assets to a loss of containment event, and applying accepted probabilities.

- Risk of commodity loss was considered using expected response time to isolate and expected pipe pressure.
- Failure of yard valves and actuators to operate as designed during an ESD has the potential to exacerbate damage to non-company infrastructure, and commodity loss. In an extreme case, it would be possible for a yard valve and actuator failure to affect non-company property within the PIR of a station and/or experience commodity loss. In this case, damages can worsen for agricultural operations in close proximity to the compressor station; neighbouring residences and businesses; and/or, electrical transmission corridors.
- Yard valve and actuator failures have the potential for significant commodity loss. Fail Closed Emergency Shutdown valves are meant to mitigate risk by ensuring that sections of pipe can be isolated during a loss of containment event.
- Yard valve and actuator failures can cause significant damages to company facilities – including compression. Given the age of the compression equipment, repairs may not be possible, resulting in replacement.

Customer Satisfaction Risk: A large component of customer satisfaction risk is related to the integrity of yard valves and actuators. Failures, especially during late season withdrawal, can have a highly disproportionate impact on Gas Supply costs. A single yard valve actuator failure can shut down an entire compressor station.

- Yard valve and actuator failures can produce moderate increases in methane emissions to the atmosphere.
- Failure of yard valves and actuators can result in loss of Storage deliverability and performance, hence affecting operational reliability. Loss of deliverability would trigger the need to secure gas from alternate sources, at additional gas supply cost, the duration of which would depend on the magnitude of the failure.

5.4.7.4 Strategy

Many yard valves are known to have seal quality deterioration based on SMA input.

There is a targeted replacement of yard valves and actuators to mitigate process safety risks. Valve replacements will be based on recent experience and understanding of SMAs, and include the following:

- Upgrading the valve actuators at SSOM to address obsolescence
- Overhauling the valve actuators at SCHT to address poor condition
- Replace yard valves at SCOR to address poor seal quality

EGD continues to enhance its understanding of asset health and life cycle cost for valves and valve actuators, which will inform future capital investment requirements.

5.4.8 Controls and Communications Devices

Control and communication assets are typically electronic in nature and their life cycle is controlled by obsolescence rather than condition. These systems are essential to the efficient, safe, and reliable operation of the Storage system and are used to detect and react to unsafe operating conditions, provide stable system operation, and minimize personnel needed to operate the Storage system. These assets allow the Storage system to operate as close as possible to maximum performance with maximum reliability.

Control and communication assets experience a steady probability of failure over many years, but eventually experience an increasing repair cost per failure and outage duration when assets become obsolete and are superseded by newer products and replacement parts for older systems are no longer produced by the manufacturer. As a result, asset replacement becomes an economic or risk-based decision, rather than condition.

5.4.8.1 Condition Methodology

Condition assessment for these assets is not practical; instead the condition is affected by planned obsolescence. The methodology for establishing condition is to consider the expected production life cycle of typical control and communications devices and systems, and proactively anticipating obsolescence.

Typically, production life cycle varies by device type, grouped as follows:

- SCADA (including Industrial Data Centres (IDCs), Human Machine Interfaces (HMIs), and video screens)
- PLC (Programmable Logic Controller) systems
- Control rooms

- Fibre optics
- Radio assets (towers and radio equipment)
- RTU (Remote Telemetry Unit) systems
- UPS (Uninterruptible Power Supply) systems
- Field instruments and controllers

Currently, the condition of controls and communications systems is determined using the experience and recommendations of SMAs. As condition modelling improves for Storage, an inventory of controls and communications equipment will be developed to allow a proactive replacement strategy based on time to obsolescence.

5.4.8.2 Condition Findings

The current state of these asset groupings is as follows:

SCADA

- Existing graphics screens were installed in 2016 and have a life expectancy of three to five years. Unlike most video equipment, these screens operate 24/7, and regular replacement is recommended by SMAs to provide optimal alarm and fatigue management.
- Existing HMIs at the new SCOR control room were installed in 2016. Life expectancy is three to five years.
- The SSOM station is the Disaster Recovery Site (DRS) for the SCOR station. Current video display capability is inadequate for a DRS.
- Existing IDC at SSOM is poorly located with inadequate security and inadequate cooling air supply. IDC equipment has a life expectancy of approximately five years.
- The Gas Storage SCADA system is up to date and must continue to be regularly upgraded with the most up-to-date standards for security.

PLC Systems and RTUs

- Older PLC systems are no longer supported by the manufacturer and are approaching end-of-life. These operating systems need to be upgraded to the latest generation control systems.

Control Rooms

- Chatham D was built in 1997. Since then, electrical, communications, and instrumentation infrastructure have grown (due to compliance and communication enhancements) since initial installation of the station. Currently, there is insufficient space to accommodate any new devices. Lately, new devices have been installed on an external wall to accommodate increasing instrumentation demands.
- The current Local Area Network (LAN) consists of a panel located in the open and with minimal security. In addition, the LAN cabinet is noisy, collects dirt and dust through the fans, and has inadequate cooling. The IDC is housed in the LAN cabinet. IDC data storage capacity is also marginal and requires expansion. LAN/IDC operation is critical for a facility designated as a DRS.
- Only qualified compressor operators are allowed to manipulate system operation. Operators in training would benefit from having a hands-on training program that simulates system operations.

Fibre Optics

- A growing number of systems at SSOM, SCHT, and meter stations require access to the telemetry system, exceeding the bandwidth provided by existing infrastructure. Newly installed security systems, and operations cameras will further strain this system and its reliability in coming years.

Radio Assets

- Current radios are 10 years old and obsolete. Failure of one radio can bring down part or entire communication system. Radio towers are susceptible to lightning strikes, which can result in the loss of data and control of assets.

UPS Systems

- UPS systems experience battery degradation. Degradation is monitored using built-in diagnostics. Systems degrade and may not be able to adequately power electronic control systems during a power outage. Normal life cycle is about three years.

Field Instruments and Controllers

- Field instruments and controllers are approaching reaching end-of-life. Longer lead times and higher replacement costs were experienced when sourcing replacement parts.

5.4.8.3 Risk and Opportunity

The consequence of controls and communications failures is dominated by the gas cost impact to customers. Customer satisfaction risk associated with controls and communications failure is diminished by the time of year and weather severity. Safety risks tend to be steady throughout the annual turnover cycle.

Safety Risk: Control and communication systems can have a direct influence on safety risk to the public and employees. The reliability and redundancy of modern control and communication designs are able to prevent loss of containment due to human error in a complex plant environment. Safety improvements can be realized by improved alarm and fatigue management practices and technologies. Control and communication systems are the first line of defense for public and worker safety and are designed to trigger fail safe shutdowns of process equipment when a failure occurs. Unmitigated obsolescence of these assets has minimal impact to public or personnel safety because obsolescence does not increase probability of failure.

Improvements to safety risk are possible as new process safety threats are identified (such as cyber security) and controls and communications systems are improved. One such example is the increased focus on site security where more security cameras are needed, but the SCADA system bandwidth is inadequate.

Financial Risk:

- Escalating cost of parts for obsolete equipment is a key financial risk driver.
- Unmitigated obsolescence of control and communication assets will result in substantially increased cost to maintain existing assets, due to parts price increases.

Customer Satisfaction Risk: Customer satisfaction risk is often considered in risk assessments because obsolete equipment can cause extended outage durations. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single control and communication device failure can influence the operability of a compressor station.

- Operational reliability risks affecting control and communication obsolescence include prolonged outages of individual units and prolonged outages of entire compressor stations. These outages would be a result of a long duration critical component failure stemming from extended lead times. Increasing operational risk is a direct result of increasingly long lead times to source parts. During prolonged outages, gas supply cost to regulated customers will increase.

5.4.8.4 Strategy

Targeted upgrades/replacement of control and communication assets is required to mitigate obsolescence, ensure adequate redundancy of critical systems and mitigation of emerging process safety risks:

- Upgrading and replacing obsolete radio communication devices
- Installing and upgrading server, software, and hardware components of the primary operating interfaces approaching end-of-life to maintain required operating performance
- Implementing a program to replace industrial data centres at SCOR and SSOM
- Upgrading the PLCs at SCOR and SSOM to maintain manufacturer supportability
- Expanding and updating the SCHT Control Room with climate controls, UPS redundancy, and security systems
- Installing individual fibre links from SCOR compressors to the core network to increase communication redundancy and minimize outage risk
- Developing training material, including simulated situations and expected scenarios, to provide a standard and comprehensive training program for operators in training
- Installing wireless service in the plant and obtaining field equipment able to securely access and update records in the necessary systems
- Upgrading SCADA to ensure electronic control systems are configured, updated and secured
- Upgrading communication links between Tecumseh, Mid/South Kimball, Sombra, and Wilkesport compressor/meter stations
- Upgrading instrumentation and electrical controls at SSOM and connecting them to the existing remote input/output devices to allow remote visibility and automation
- Installing a LAN room at SSOM with climate controls and security systems

5.4.9 Electrical Devices

Electrical assets are a broad grouping which includes:

- Auxiliary Power Units (APU)
- Transformers
- Motor Control Centres and Variable Frequency Drives (VFD)
- Phase inverters
- Lighting systems

Electrical assets do not include electric motors because motors are usually a core sub-component of other sub-assets – such as gas compressor aftercooler fan and JWC fan motors.

Electrical assets support many other sub-asset types – these assets are needed to operate air compressors, control and communication systems, heating systems, cooling systems, building systems, etc. As a result, electrical systems have a widespread scope of impact, such that the failure of a single electrical asset can have consequences throughout an entire compressor station. Risks related to electrical supply are partially managed through redundancy (UPS and APU equipment provide redundant electrical supply in the event of an electricity outage), which is a practical approach since electrical equipment is less expensive when compared to gas carrying sub-assets.

Electrical assets experience an increasing probability of failure over many years, but eventually experience an increasing repair cost per failure and outage duration when replacement parts for older systems are no longer produced by the manufacturer.

There is currently an expectation that the condition of electrical assets will necessitate replacements or repairs within the timeframe of the 10-year Asset Management Plan. Justification for replacements is based on increased consequence of failure due to obsolescence.

5.4.9.1 Condition Methodology

Condition of electrical assets, as defined for Storage, is primarily affected by planned obsolescence. As such, condition assessment for these assets is not practical. Instead, the methodology for establishing condition is to consider the expected production life cycle of typical electrical devices and systems, and proactively anticipating obsolescence.

5.4.9.2 Condition Findings

APUs: The existing transfer switch (used to control up to 600 VAC, three-phase circuits) requires that the entire plant be de-energized and de-pressurized to perform maintenance/repairs. It is also approaching its end-of-life. Currently, SMAs have not identified condition concerns related to other APUs assets.

Transformers: Currently, SMAs have not identified condition concerns related to transformer units.

Motor Control Centres and VFDs: Existing gas aftercoolers are On/Off fan drives. On/Off fan drives consume more electricity and create higher demand charges due to in-rush current when starting up. High torque created during start-up increases mechanical loads on the gas aftercooler structure, leading to increased maintenance.

Phase Inverters: The inverter at SCHT has been identified by SMAs as having poor reliability (frequent failures requiring repair) and is approaching end-of-life. SMAs have not identified condition or reliability concerns related to other phase inverters.

Lighting Systems: Light pole installation dates back as far as 1964. These older light poles have been identified to have corrosion, specifically at the base of the light pole. Corrosion at this location may jeopardize structural integrity.

5.4.9.3 Risk and Opportunity

The consequence of electrical device failures is dominated by the gas cost impact to customers. Customer satisfaction risk associated with electrical device failure is diminished by the time of year and weather severity when the failure occurs. Safety risks tend to be steady throughout the annual turnover cycle.

Safety Risk: Electrical systems have an indirect influence on safety risk to the public.

- Unmitigated obsolescence and/or reduced operational reliability of these assets have minimal impact on public safety because electrical system failures result in a shutdown of gas carrying mechanical equipment.
- Electrical systems can have a direct impact on employee safety related to maintenance activities where electrical assets must be de-energized and then re-energized.

Financial Risk:

- Escalating cost of parts for obsolete equipment is a key financial risk driver.
- Unmitigated obsolescence and/or reduced operational reliability of electrical assets can result in substantially increased cost to maintain existing assets, due to price escalation for parts.

Customer Satisfaction Risk: Customer satisfaction risk is often considered in risk assessments because obsolete equipment can cause extended outage durations. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single electrical device failure can shut down an entire compressor station.

Operational reliability risks affecting electrical obsolescence include prolonged outages of individual units and prolonged outages of entire compressor stations. These outages would be a result of a long duration critical component failure stemming from extended lead times. Increasing operational risk is a direct result of increasingly long lead times to source parts. During prolonged outages, gas supply cost to regulated customers will increase.

Opportunities

Upgrading of electrical devices, like replacement of motor starters to VFDs, is expected to reduce annual electrical cost and improve ability to monitor performance and troubleshoot abnormal motor behavior.

5.4.9.4 Strategy

Targeted upgrades/replacement of electrical devices includes the following:

- Replacing existing transfer switch with a new unit which employs a wrap-around bypass to reduce the risk of transfer switch failure.
- Replacing existing On/Off cooling fan motor starters with VFDs.
- Replacing light poles showing signs of corrosion.
- Replacing phase inverters experiencing reliability concerns.

5.4.10 Metering Systems, Flow Control Systems, Dehydrators, and Incinerators

Anticipated capital expenditure for the grouping of metering system, flow control valves, and dehydrators & incinerators is expected to be low within the timeframe of the Asset Management Plan. As such, these assets are grouped together because they have similar risks and life cycle management strategies and condition modelling for these assets is in its preliminary stages.

Metering Systems are used primarily to manage or support the storage inventory. These systems include assets such as process meter runs and gas chromatographs at SSOM. If unmitigated, risks related to obsolescence and operational reliability is generally expected to increase over time because of the increasing cost of parts.

Flow Control Valves are used extensively during early injection and withdrawal and are essential to control flow rate. Most flow control valves within compressor stations were installed in 1998 or later. Given their relatively low calendar age, these assets are expected to be in relatively good condition. Flow control valves are a repairable sub-asset type because they are always located above-grade, normally installed with sufficient isolation to allow removal without significant system upset, and are designed to be disassembled for easy replacement of wear items. Replacement of control valve assets is normally driven by obsolescence or a change in performance requirements.

Dehydrators and Incinerators are a repairable sub-asset type used primarily to manage moisture content during withdrawal. Most compressor stations use dehydration to remove moisture from storage gas late in the withdrawal season. Dehydration for SCOR is provided through a contracted service with UGL. SCHT, SCRW and SSOM all have dedicated dehydration systems within the compressor station.

5.4.10.1 Condition Methodology

The understanding of the current state and condition of the metering system, flow control valves, dehydrators, and incinerators is based on SMA input. Condition assessment methodologies are expected to be implemented for this grouping of assets in the future.

5.4.10.2 Condition Findings

The condition of the metering system, flow control valves, dehydrators, and incinerators are generally thought to be very good, due in large part to age, with the exception of the Black Creek Inventory Management meter located at SSOM.

Metering Systems: Existing meters at SSOM are still used for inventory management of the Black Creek reservoir. The Black Creek Inventory Management meter is obsolete and no longer supported by the manufacturer. Parts are expensive compared to the current UT Meters standard used at Storage. Diagnostics on new meters are also superior to old technology. Currently, SMAs have not identified condition concerns related to any other metering systems.

Flow Control Systems: Currently, SMAs have not identified condition concerns related to flow control systems.

Dehydrators and Incinerators: SMAs have not identified condition concerns related to existing automated dehydrators and incinerators at this time. Currently all dehydrators and incinerators are fully automated, with the exception of the unit at Chatham D, a manually operated dehydrator that could experience an undetected failure, resulting in a substantial spill of triethylene glycol to the environment. Automation would provide additional monitoring of the dehydration process during system operation.

5.4.10.3 Risk and Opportunity

Given the relatively low age of these assets, escalation of risk is not expected for many years.

Safety Risk: Failures within this asset grouping have a moderate influence on public safety risk, especially where the asset influences over-pressure protection.

- Loss of containment has the potential to injure the public and workers, causing leaks and creating flammable mixtures. Incinerators, in particular, are intended to remove elevated benzene constituents from dehydration off-gas. Benzene is a threat to public and personnel safety.

Financial Risk:

- Key financial risk drivers are the escalating cost of parts for obsolete equipment, the potential for third party and company damages, commodity loss, and environmental cleanup. These risks are expected to be more significant sometime after the 10-year plan.
- Failures have potential to damage non-company infrastructure, and can incur significant commodity loss. An asset grouping failure can cause a large event, affecting non-company property within the PIR of a compressor station and/or experience commodity loss. In this case, there could be damages to agricultural operations in close proximity to the compressor station; neighbouring residences and businesses; and/or, electrical transmission corridors.
- Failures within this asset grouping have the potential for moderate commodity loss. Fail Closed Emergency Shutdown valves mitigate this risk by ensuring that affected sections of pipe can be isolated during a loss of containment event.
- Failures within this asset grouping failures can cause significant damages to company facilities, including compression. Given the age of the compression equipment, repairs may not be possible.

Customer Satisfaction Risk: Customer satisfaction risk is often considered in risk assessments because obsolete equipment can cause extended outage durations. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single failure within this grouping of assets can shut down an entire compressor station.

- Failures within this asset grouping can produce moderate increases in methane emissions to the atmosphere. The extent of an uncontrolled release can be mitigated by initiating a plant-wide ESD which closes all plot edge valves and vents all process piping.
- Failures within this asset grouping can result in loss of Storage deliverability, hence reduced operational reliability. A loss of containment will require an immediate shutdown of Storage operations, evaluation of any

damage, and development and execution of a business resumption plan. Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost.

- Operational reliability and obsolescence risks affecting these grouped assets include prolonged outages of associated reservoirs and flow restrictions at custody transfer points. Outages would be a result of a critical component failure, stemming from extended lead times. Increasing operational risk is a direct result of increasingly long lead times to source parts. During prolonged outages, gas supply cost to regulated customers will increase.

5.4.10.4 Strategy

Targeted upgrades/replacement of this grouping of assets primarily focuses on the metering system and the dehydrator and incinerator, specifically:

- Upgrading the obsolete and unsupported Ultrasonic meters at SSOM with new units
- Upgrading the dehydrator and incinerator at SCHT to a fully automated unit

EGD continues to enhance its understanding of asset health and life cycle costs for metering system, flow control valves, dehydrators and incinerators, which will inform future capital investment requirements.

5.4.11 Filters, Separators, and Tanks

Filters, separators, and tanks (including pressure vessels and atmospheric tanks) are used extensively during withdrawal, to capture reservoir fluids and particulate. These devices are essential to the reliability of compression because particulate and fluids can damage moving parts.

5.4.11.1 Condition Methodology

The understanding of the current state and condition of the filters, separators, and tanks is based on SMA input and supported by the in-progress pressure vessel and tank inspection program that is under development. Condition assessment of filters, separators, and tanks are currently underway.

5.4.11.2 Condition Findings

Pressure vessels and tanks are exposed to several factors affecting condition. Direct (measureable) threats to containment include internal corrosion, external corrosion, thermal stresses caused by variability in gas temperatures, and vibration caused by compressors. Indirect threats to containment include effectiveness of pressure control systems, and over-pressure protection systems. The state and condition of filters, separators and tanks is as follows:

Filters and Separators: With older style filters and separator vessel closures, it is difficult to determine whether the filter and separator vessels have been completely depressurized before attempting to open the closure door, posing a hazard to maintenance personnel. New style filter and separator vessel closures, installed at most locations at Gas Storage, mitigate this risk by ensuring the opening of the closure is prevented while the vessel is under pressure.

Tanks: The current inspection program under development for pressure vessels and tanks has identified the following condition findings:

- Corrosion causing a breach of the liquids tank at SCHT
- Corrosion on the secondary containment of some of the tanks at all compressor stations

In addition, liquids can enter these tanks at a high velocity, causing spillage out of the tank's vent. Recent code changes (*CSA Z662*) now require demonstration that the design pressure of an atmospheric tank connected to a high pressure low point drain system is adequate for its intended service.

5.4.11.3 Risk and Opportunity

The consequence of filter, separator, and tank failures is dominated by the gas cost impact to customers. Customer satisfaction risk is diminished by the time of year and weather severity when the failure occurs. Safety risks tend to be steady throughout the annual turnover cycle.

Safety Risk: Filters, separators, and tanks have a moderate influence on public safety risk, especially where the asset influences over-pressure protection.

- Loss of containment has the potential to injure the public and workers, causing leaks and creating flammable mixtures. These assets have a moderate influence on worker health and safety from exposure to reservoir liquids during maintenance activities (cleaning).

Financial Risk: Key financial risk drivers are escalating cost of parts for obsolete equipment, potential for third party and company damages, commodity loss, and environmental cleanup. These risks are expected to be better understood after completion of the condition assessment program.

- Filter, separator, and tank failures have potential to damage non-company infrastructure, and can incur significant commodity loss. A filter, separator, or tank failure can cause a large event, affecting non-company property within the PIR of a compressor station and/or experience commodity loss, resulting in damages to agricultural operations, residences, and businesses in close proximity to the compressor station, and electrical transmission corridors.
- Filter, separator, and tank failures have the potential for moderate commodity loss. Fail Closed Emergency Shutdown valves mitigate this risk by ensuring that affected sections of pipe can be isolated during a loss of containment event.
- Filter, separator, and tank failures can cause significant damages to company facilities, including compression. Given the age of the compression equipment, repairs may not be possible and replacement may be recommended.
- Filter, separator, and tank failures could result in significant environmental cleanup cost related to reservoir fluids.

Customer Satisfaction Risk: A large component of customer satisfaction risk is related to asset integrity. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single process pipe failure can shut down an entire compressor station for a long duration.

- Filter, separator, and tank failures can produce moderate increases in methane emissions to the atmosphere. The extent of an uncontrolled release can be mitigated by initiating a plant-wide ESD which closes all plot edge valves and vents all process piping.
- Filter, separator, and tank failures can result in loss of Storage deliverability, hence reduced operational reliability. A loss of containment would require an immediate shutdown of Storage operations, evaluation of any damage, and development/ execution of a business resumption plan. Loss of deliverability would trigger the need to secure gas from alternate sources at additional gas supply cost.

5.4.11.4 Strategy

Targeted upgrades/replacement of filters, separators and tank assets is required in the 10-year Asset Management Plan to mitigate known condition concerns and to complete the development of the inspection program. Until condition assessment data is available, filter, separator, and tank replacements will be based on recent experience and understanding from SMAs. Specific strategies are as follows:

- Replace tanks and associated secondary containment in poor condition.
- Design and install platforms for worker safety when changing filter elements and working around separators. Replace older style filter and separator vessel closures that pose a potential hazard to maintenance personnel.
- Replace atmospheric tanks with pressure vessels designed to connect to high-pressure, low-point drain systems.
- Complete the development of the Pressure Vessel and Tanks Inspection Program to develop a more complete understanding of life cycle costs and develop forecasting tools.

5.4.12 Pipelines - Transmission, Pool, Gathering, and Laterals

Pipelines assets are a critical component of gas storage operations. Gas storage pipeline assets transport gas between custody transfer points and reservoirs. Four pipeline asset sub-classifications exist within the Storage asset class:

- **Transmission Pipelines** connect compressor stations to custody transfer points or other Transmission Pipelines. Transmission pipelines owned by EGD generally possess isolation valves at the custody transfer point.
- **Pool Pipelines** connect compressor stations to reservoirs. Multiple reservoirs can be connected to a single compressor station by individual pool pipelines. Inventory management meters are generally installed within the pool pipeline. In a few cases, inventory management meters are included as part of the gathering pipeline.
- **Gathering Pipelines** refers to the central collection/distribution lines that interconnect wells within a reservoir and includes one field isolation valve per reservoir. Gathering pipelines are generally larger diameter pipe - matching the size of the associated pool pipeline - to collect/distribute gas effectively to smaller well laterals.
- **Laterals** connect individual wells to a gathering pipeline. Laterals are generally NPS10 in size. In some cases, more than one well is connected to a single branch connection extending from the gathering pipeline. Laterals include a "well loop" that interconnects a line valve with a master valve.

The age of storage pipelines by type can be seen in **Figure 5.4-8**.

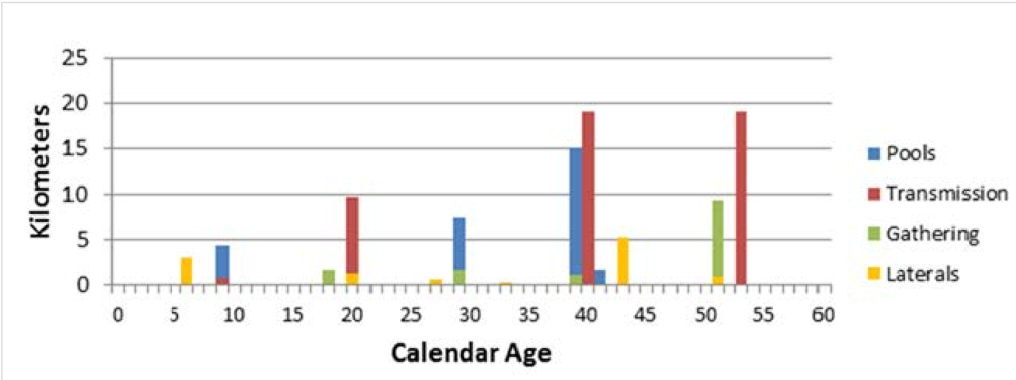


Figure 5.4-8: Age of Storage Pipelines

Pipeline condition is assessed through the TIMP using in-line inspection tools. Condition definitions used are similar to those used by the Asset Health Review.

EGD's Storage Operation began in 1964. Initially, pipelines were designed to manage inventory associated with four reservoirs (Mid Kimball-Colinville, South Kimball-Colinville, Corunna, and Seckerton). Managing this inventory required one NPS30 transmission line to the UGL Dawn system, four pool pipelines, four gathering pipelines, and dozens of laterals. Since 1964, new transmission lines and new reservoirs have been developed requiring new pool pipelines, gathering systems, and laterals.

All Storage pipeline assets are steel, with a SMYS at MOP ranging from 72% to 80%. MOPs vary depending on the reservoir's characteristics and approved pressure gradient. Some of the more recent pipelines were constructed with a MOP that matched a PN100 flange rating – 9928 kPa (1440 psig).

Pipeline assets are buried and located in an agricultural area. Very little of the piping system is installed in a Location Class 2 area, but much of the piping system is capable of operating in a Location Class 2, with the exception of the Ladysmith Pool Pipeline (2008) operating in a Location Class 1. Road crossings and watercourse crossings exist.

The largest operational threat to the pipeline system is internal corrosion/erosion due to entrained reservoir liquids and solids. Third party damage is also a significant threat due to annual installation of agricultural drain tile by landowners. Third party damage potential has diminished recently with Ontario One Call legislation.

Materials from pre-1977 pipelines typically have unknown notch toughness characteristics. This issue can lead to extensive pipeline damage, repair cost, and outage duration in the event of a line rupture. Provided that the pipelines are not exposed to third party damage threats, this issue does not affect the probability of failure, but dramatically increases consequence of failure. While this is not a condition-related threat, it should be noted as a vulnerability.

Pipelines are inspected regularly for leaks, depth of cover, and effectiveness of the cathodic protection system. Aerial inspections are also performed. The system is monitored for changes in area class location due to encroachment. Transmission, pool, and gathering pipelines and many laterals are now piggable. Laterals that are not piggable are inspected using guided wave inspection.

5.4.12.1 Condition Methodology

Refer to **Section 5.2.4.1** for the condition methodology of Storage pipeline assets**.**

5.4.12.2 Condition Findings

Asset Health Review results were calculated based on the latest Magnetic Flux Leakage inspection for each Storage pipeline as of the end of 2017.

The Storage Asset Class consists of 75 pipelines in the storage area near Sarnia. Of the 75 pipelines, 41 have metal loss features that may eventually require remediation. **Figure 5.4-9** shows the number of pipelines in each of the Health Index categories.

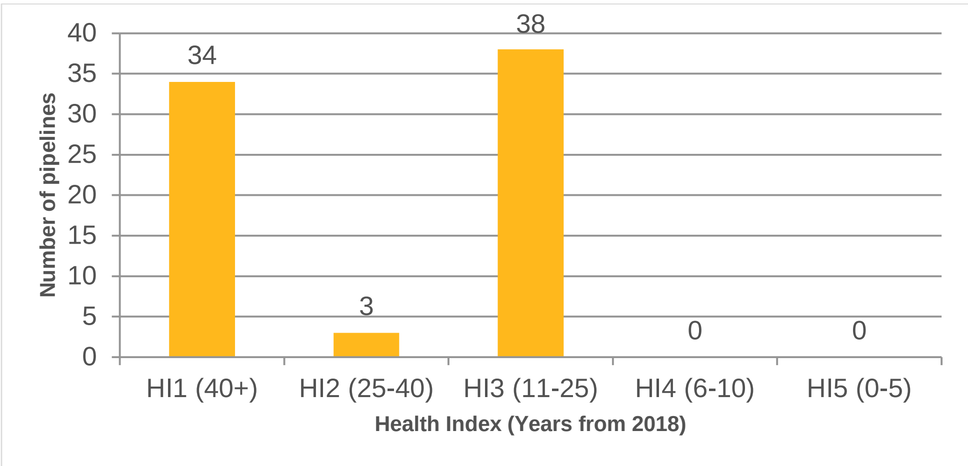


Figure 5.4-9: Storage Pipeline Health

A total of 658 digs would be required across the 41 pipelines to fully remediate all metal loss features, using a standard dig length of 10 meters. **Figure 5.4-10** shows the number of digs that would be required in each of the Health Index timeframes.

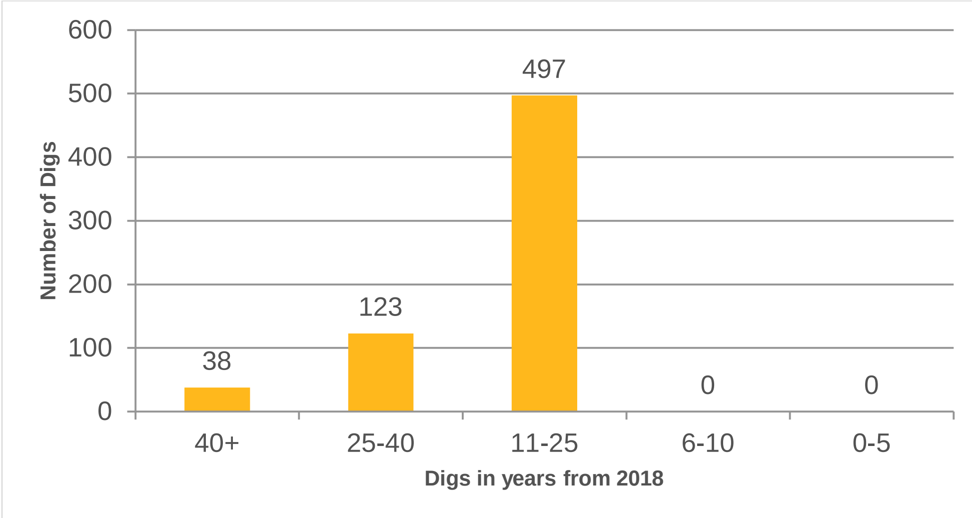


Figure 5.4-10: Storage Dig Forecast

Future integrity digs are not spread uniformly across the pipelines. The pipeline with the largest number of digs is the NPS 20 South Mid-Kimball gathering pipeline, which will require 175 digs (over a quarter of all of digs). The pipeline with the next highest number of digs is the NPS 16 South Mid-Kimball gathering pipeline, which has 86 digs. The top 10 pipelines account for 80% of the digs. **Figure 5.4-11** shows the dig distribution of the top 10 pipelines.

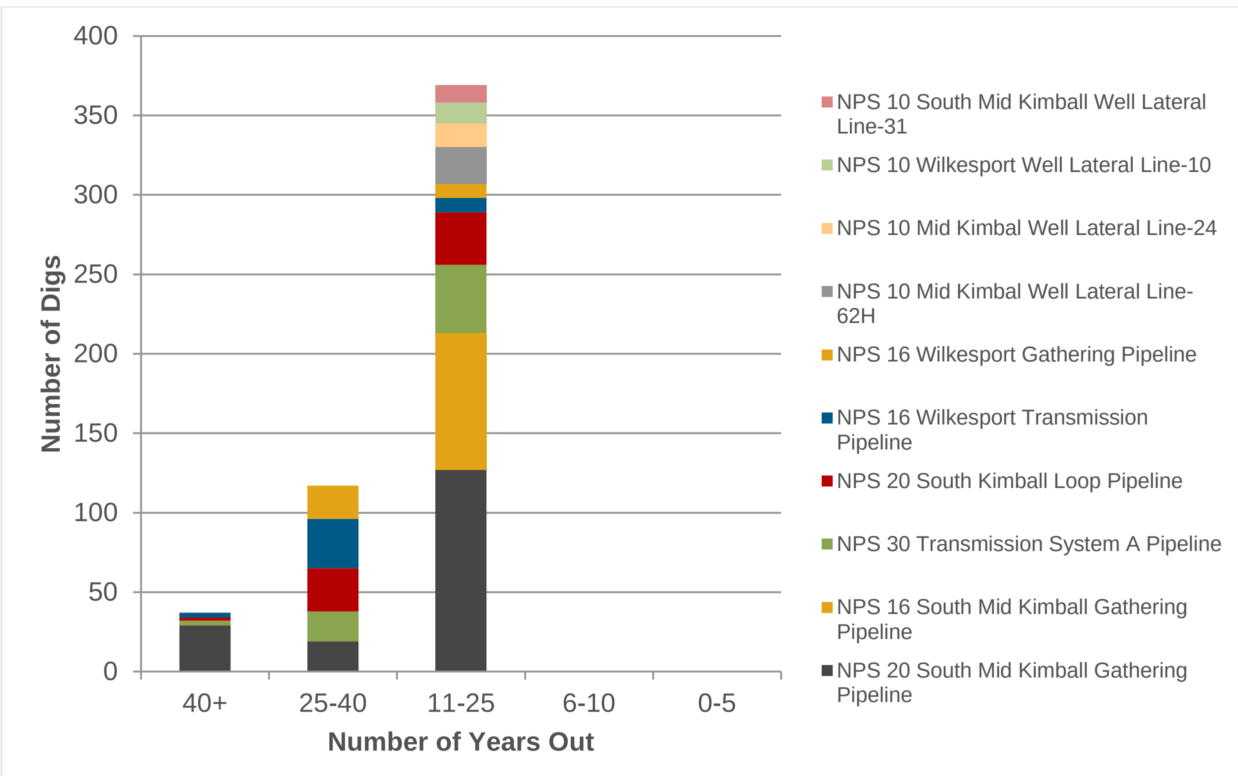


Figure 5.4-11: Storage Top 10 Pipelines for Digs

The two pipelines with the most digs in the 11-25 year category are the NPS 16 and NPS 20 South Mid-Kimball gathering pipelines, both scheduled for re-inspection in 2018. Features will be reset to actual sizes instead of estimates. The next analysis will give a more accurate forecast of digs required and a pipeline-specific corrosion growth rate.

Well Loops: The general condition of well loops are considered good, however after installation, the soil surrounding laterals has been found to compact and subside. In instances where compaction is severe, the soil no longer provides adequate support for the pipe. The weight of the pipe is instead supported by the well loop which attaches the lateral to the well. The well loop is not intended or designed to support this additional and significant strain, leading to a potential leak in the reservoir piping system. Normally, these situations are discovered during the annual vertilog program, when well loops are removed. Piping can settle for as long as ten years between vertilogs. Once discovered, the excess pipe strain will be mitigated and piping modifications are required.

5.4.12.3 Risk and Opportunity

Currently, the TIMP shows no condition issues requiring immediate remediation over the duration of the 10-year period. Some ongoing capital spend is required in the 10-year period, as needed to prepare pipelines for continued in-line inspection.

Safety Risk: Pipelines have a major influence on public and employee safety risk during a loss of containment event.

- Low notch toughness properties of some older pipe increases the probability that a localized pipeline failure can propagate and potentially increase the hazard to personnel and the public.

Financial Risk: Pipelines represent financial risk to EGD and customers in the event of a failure.

- Unexpected pipeline failures carry a large cost of replacement, which is magnified by the low notch toughness characteristics of pre-1977 pipe. In addition to replacement costs, loss of product can occur.

Customer Satisfaction Risk: Operational reliability consequences of an unexpected failure can be material for customers.

- Loss of deliverability would trigger the need to secure gas from alternate sources, at additional gas supply cost, the duration of which would depend on the magnitude of the failure. Transmission pipelines represent the greatest risk because they comprise the main artery for gas deliveries to the Dawn pipeline system. Pool and gathering pipelines and laterals represent a smaller risk, because an outage from a single reservoir would still allow remaining reservoirs to operate.

5.4.12.4 Strategy

Current indications show pipeline condition varies from very good to fair. Targeted upgrades and replacement may be required starting after the horizon of this Asset Management Plan.

Life cycle management involves the continued direct measurement of pipeline condition for signs of corrosion and possible pipe damage through the in-line inspection program.

EGD continues to assess the condition of pipelines, perform regular in-line inspections and employ the condition data to forecast the timing of proactive replacements, based on observed corrosion rates, which will inform future capital investment requirements. Specific pipeline strategies at this time include:

- Maintain adequate cathodic protection systems to protect the pipelines from corrosion.
- Reactively replace well loop piping under strain due to buried pipe settlement.
- Install pressure-indicating transmitters at the entry point of pipelines into compressor stations to validate the performance of the storage pipeline system.

5.4.13 Pipeline Valves

Pipeline valves direct the flow of gas through pipelines and pipeline interconnects. The scope of the pipeline valves sub-asset components is limited to NPS4 valves and larger, and is distinct from valve systems within compressor stations.

Available maintenance history information is centered on actuators, specifically the reliability with which valves swing to their fail position. This means that condition analysis is currently based on actuator operation reliability. More recently, pipeline valves have been viewed in the context of whether they seal when closed. If a valve does not seal when closed, then a loss of containment occurs within the pipeline network, which may not be controllable.

A bar chart distribution of pipeline valve quantity versus calendar age is shown in **Figure 5.4-12**. Age distribution is depicted as at the end of 2016. Valve inventory includes NPS4 and large pipeline valves. Pipeline valves at Crowland are not included as they are not tracked in Maximo.

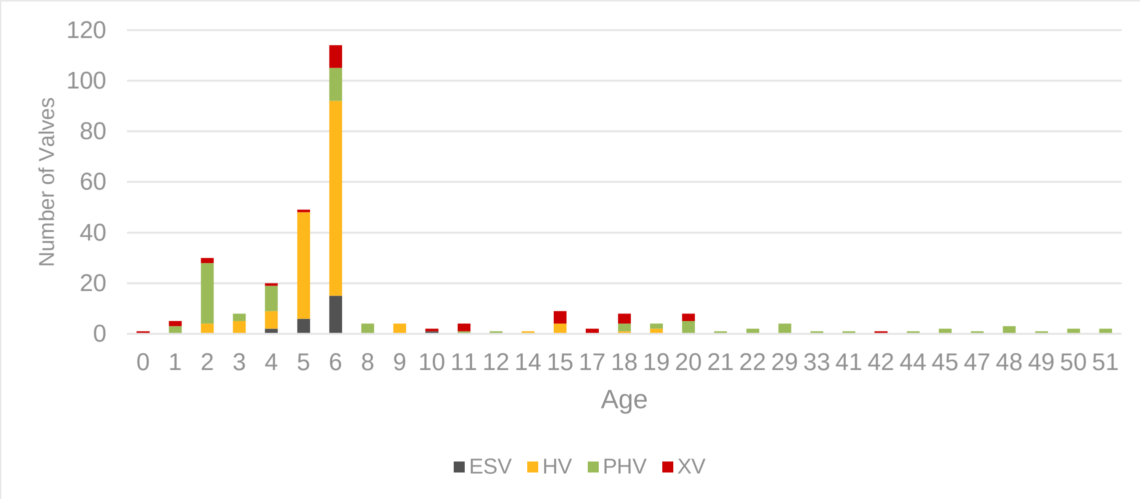


Figure 5.4-12: Pipeline Valves – Age

5.4.13.1 Condition Methodology

The condition of pipeline valves is determined by SMA input. SMAs have identified several failure factors that can potentially contribute to accelerated degradation of these assets. Some of these factors include size, pressure difference, and location (above-ground or underground).

Of the different failure types, the most significant is bypass failure. Storage Operations is investigating quantitative methods to assess valves for bypass failure.

5.4.13.2 Condition Findings

SMAs have indicated that many pipeline valves are known to have seal quality deterioration to such an extent that they cannot be relied upon during some maintenance activities.

There is currently a moderate expectation that pipeline valves and actuators need replacement within the timeframe of the 10-year Asset Management Plan. Many pipeline valves are manually operated, smaller, and easily replaceable. Buried actuated valves exist at meter stations and pipeline interconnects, used as field isolation valves. Meter station valves are all relatively new, although they have a high frequency of operation. High operating frequency creates accelerated wear of sealing elements and may require replacement.

Line valves are particularly problematic because they need to seal properly for all related reservoir work. Well work requires removal of the well loop in order to enter the well. If the line valve does not seal properly after removing the well loop, weeping gas from the gathering system can make the work area more hazardous until a blind flange is installed.

Valve seal quality cannot be compared with valves in other asset classes because the operating conditions are unique to Storage. Pipeline valves at Storage can experience high differential pressures, crude oil, brine and reservoir particulate, and run at a high operating frequency. These factors influence valve seal quality to varying degrees. Future modelling with the Asset Health Review tool will use these factors to gauge seal quality.

Based on SMA input, moderate investments are required to replace pipeline valves. The 10-year Asset Management Plan is reflective of this assessment. Ongoing work through the Asset Health Review is expected to provide additional analytical support related to valve health.

Valve Actuator ESD Bottles: Gas-powered valve actuators in meter stations use an ESD bottle which holds a charge of power gas sufficient to swing the valve closed under an upset condition. This ESD bottle is often equipped with a PSV that is threaded into a connection point in the bottle wall. Annual testing of PSV set points requires removal of the PSV from the ESD bottle. Each time the PSV is removed and re-installed, the threads in the wall of the ESD bottle experience wear, so that the PSV thread engagement becomes deeper. Further removal of the PSV for testing will soon result in insufficient thread engagement to provide a gas seal.

5.4.13.3 Risk and Opportunity

Condition-related risks are determined to be moderate by SMAs. The consequence of pipeline valve failures is dominated by the gas cost impact to customers. Customer satisfaction risk associated with pipeline valve failure is diminished by the time of year and weather severity. Safety risks tend to be steady throughout the annual turnover cycle.

Regular inspection and testing helps to reduce risk of unexpected failure of assets significantly. For example, pipeline valves can be tested at regular intervals to ensure they are operational. This will reduce the chance of failure on demand in an emergency situation. Pipeline valve seals can be indirectly tested using the valve body bleed. Regular inspection will allow for proactively identifying and replacing valves that are not sealing properly before a significant safety hazard arises.

Safety Risk: Safety risks, including process safety, are expected to be better defined after completion of bypass failure inspections. Process safety risks are generally related to the effectiveness of a valve's ability to isolate during an emergency shutdown. In some cases, over-pressure protection may need enhancement. Generally, these risks are expected to increase over time, as valves experience wear. Replacement of fail closed valves is expected to be driven by regulatory compliance related to the ESD system, combined within an internal measure to define unacceptable leakage rates.

- Pipeline valve and actuator condition has a direct influence on safety risk to the public and employees. Inadequate gas containment by valves during an emergency situation has the potential to injure the public and workers if actuators fail to operate or if valve seals fail to fully isolate.
- Leaking pipeline valves can also compromise worker safety during maintenance operations by unintentionally exposing workers to the risks of asphyxiation, fire, and mechanical energy release.
- Process Safety risks affecting pipeline valves and actuators include over-pressure protection of pipe due to leaking valves, and reduced reliability resulting from valves being out of position.

Financial Risk: Where appropriate, damages to neighbouring businesses, residences, agricultural operations and company property have been considered in risk assessments. Consequences are evaluated using proximity of affected assets to a loss of containment event, and applying accepted probabilities. Where appropriate, risk of commodity loss may be considered using expected response time to isolate and expected pipe pressure.

- Failure of pipeline valves to operate as designed during an ESD has the potential to exacerbate damage to non-company infrastructure, and commodity loss. A pipeline valve failure can affect non-company property within the PIR and/or experience commodity loss. In this case, damages can worsen for agricultural operations, residences, and businesses in close proximity to the pipeline, and electrical transmission corridors.
- Pipeline valve failures have the potential for significant commodity loss. Fail closed emergency shutdown valves are meant to mitigate risk by ensuring that sections of pipe can be isolated during a loss of containment event.
- Pipeline valve failures can cause significant damages to company facilities – including meter stations.

Customer Satisfaction Risk: A large component of customer satisfaction risk is related to the integrity of pipeline valves. Failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single pipeline valve failure can shut down an entire pipeline and even a reservoir.

- Pipeline valve failures can produce significant increases in methane emissions to the atmosphere.
- Failure of pipeline valves can result in loss of Storage deliverability and performance and incremental loss of product during a loss of containment event from other sub-assets. Loss of deliverability could trigger the need to secure gas from alternate sources, at additional gas supply cost.

5.4.13.4 Strategy

The general replacement strategy is the targeted replacement of pipeline valves and actuators to mitigate process safety risks. Valve replacements will be based on recent experience and understanding of SMAs, and include the following:

- Replace pipeline valves in transmission and gathering pipelines and laterals to address poor seal quality.
- Upgrade ESD bottles to ensure that PSVs can be removed and inspected annually as required by *CSA Z662.*
- Increase the number of remotely controlled valves in the pipeline system.

EGD continues to enhance its understanding of asset health and life cycle cost for valves and valve actuators, which will inform future capital investment requirements.

5.4.14 Meter Stations

Metering systems are used primarily to manage storage inventory, or support the storage inventory. These systems include assets such as process meter runs and gas chromatographs along pool pipelines to each reservoir. If unmitigated, risks related to obsolescence and operational reliability is generally expected to increase over time because the cost of parts will increase as their availability declines.

Age distributions are not available at this time. All inventory meters were installed between 2011 and 2013, making them five to seven years old.

5.4.14.1 Condition Methodology

Condition of meter station assets is primarily affected by planned obsolescence. As such, condition assessment for these assets is not practical. Instead, the methodology for establishing condition is to consider the expected production life cycle of typical electrical devices and systems, and proactively anticipating obsolescence.

5.4.14.2 Condition Findings

Current findings indicate that the condition of meter station assets is generally very good, and will require minimal replacement over the course of the 10-year plan. Replacement of metering assets is driven predominantly by obsolescence and is normally an economic decision. Quantity and calendar age of metering assets is low.

Crude Carryover: The Seckerton reservoir produces liquids from gas storage wells which enters the pipeline system, a combination of brine and oil that has consistently resulted in fouling of straightening vanes and ultrasonic meter components - compromising inventory management objectives and increasing maintenance costs. While disassembling the meters for cleaning, there is potential for contact with crude oil, a healthy and safety risk. Personal Protective Equipment (PPE) is used, as required by procedures, but there is still the potential for exposure. Operational mitigation of the issue/concern has been attempted by shutting in the problem wells. The consequences of shutting in the problem wells is that there is a three week period, when Seckerton is almost empty and an estimated 1.5 BCF of gas becomes temporarily trapped and unavailable.

5.4.14.3 Risk and Opportunity

Condition-related risks are determined to be small by SMAs. The consequence of meter station failures is dominated by the gas cost impact to customers. Customer satisfaction risk associated with meter station failure is diminished by the time of year and weather severity. Safety risks tend to be steady throughout the annual turnover cycle.

Safety Risk: Metering systems have a moderate influence on public safety risk. Metering systems also have a moderate influence on worker health and safety from exposure to reservoir liquids during maintenance activities (cleaning).

Financial Risk: Unmitigated obsolescence or reduction in operational reliability of metering assets will result in substantially increased cost to maintain existing assets, due to price escalation for parts.

Customer Satisfaction Risk: Operational reliability and obsolescence risks affecting meter systems include prolonged outages of associated reservoirs. Outages would be a result of a critical component failure, stemming from extended lead times. Increasing operational risk is a direct result of increasingly long lead times to source parts. During prolonged outages, gas supply cost to regulated customers will increase.

5.4.14.4 Strategy

Life cycle management involves the continued condition assessment of meter station assets for signs of corrosion and possible pipe damage. Replacement of metering assets, based on condition, is not anticipated in the 10-year period, though upgrades or replacement of targeted metering assets may be required to mitigate currently unknown process safety risks.

Specific meter station strategies at this time are to reduce the quantity of or capture crude oil carryover at the Seckerton reservoir. EGD continues to enhance its understanding of asset health and life cycle cost for meter stations, which will inform future capital investment requirements.

5.4.15 Wells

Wells refers to the asset grouping of Observation, Vertical Injection/Withdrawal (IW), and Horizontal I/W wells.

EGD's storage wells are located in agricultural areas. Initially, wells were designed to manage inventory associated with four reservoirs – Mid Kimball-Colinville (MKC), South Kimball-Colinville (SKC), Corunna (COR) and Seckerton (SEC).

Since 1964, new reservoirs have been developed at Wilkesport (WLK), Dow Moore (DOW), Coventry (COV), Black Creek (BCK), and Ladysmith (LAD). Additional reservoirs have been added to the Gas Storage Operation either by acquisition (Chatham D – CHT) or operating agreement (Crowland – CRW).

Figure 5.4-13 shows the distribution of well quantity versus calendar age. Data depicts calendar age as at the end of 2016.

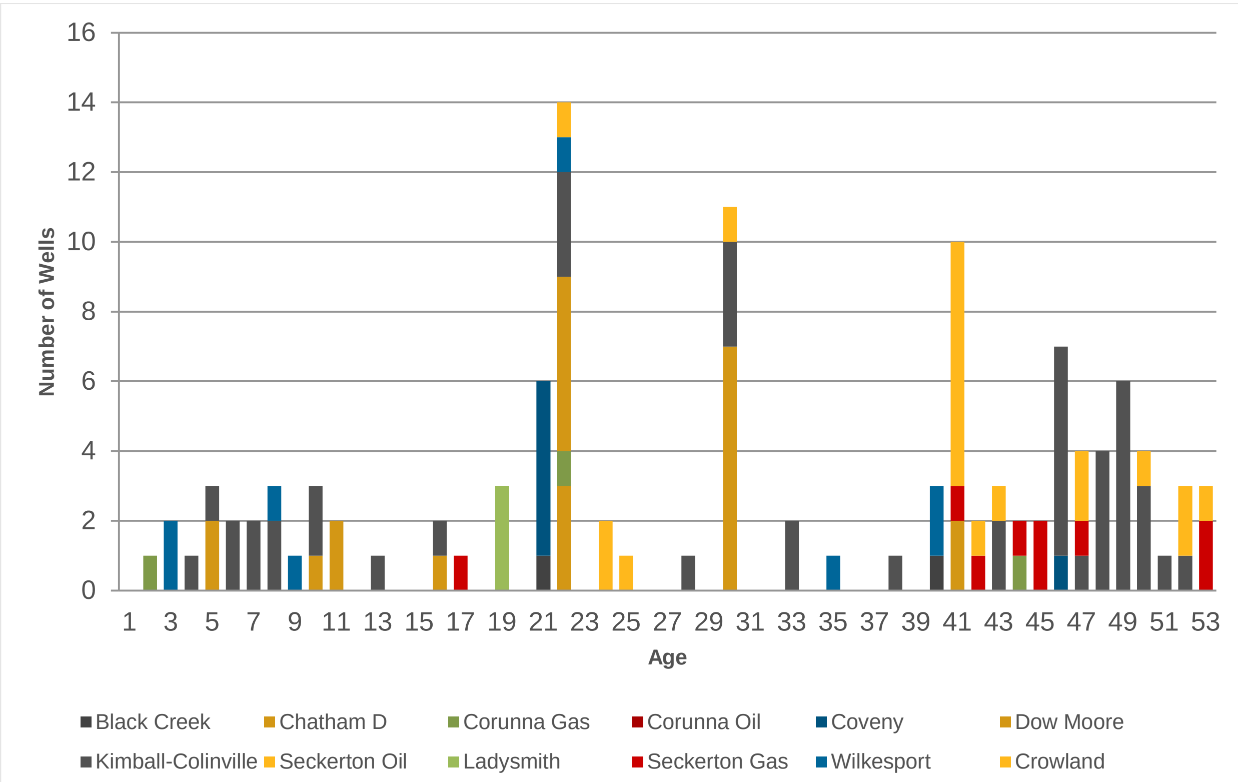


Figure 5.4-13: Storage Well Population and Age

Well assets in the 40 to 55 year age range were installed as part of the initial Tecumseh Gas storage development – MKC, SKC, COR and SEC. Well assets around 40 years of age are predominantly at CRW and WLK. Well assets in the 15 to 30 year range are newer storage reservoir developments at BCK, CHT, COV, DOW, and LAD. Installation of new well assets within the last 15 years is dominated by the A1 Observation Wells, needed to demonstrate reservoir integrity.

Repair of corroded well casing below the first 20 meters from the surface is no longer considered economically effective. Repair of these corroded well casings used to be performed by a technique known as're-lining' the production casing, performed by inserting a new smaller diameter casing inside the corroded casing and filling the annular space with cement. Recently, re-lined wells have been discovered to be leaking through the cemented annular space (i.e., micro annulus leaks). The practice of relining wells has also been terminated because the resulting well exhibits greatly reduced flow performance and is viewed as uneconomical when compared to drilling a new well.

The top two joints of corroded well casing (approximately the top 20 meters from the surface) are still being repaired. These repairs are known as 'back-offs'. Back-offs result in the removal of a short section of old casing and replacement with new casing, and restoration of life expectancy.

Wells at Dow Moore were originally equipped with a rectified cathodic protection system. The system was eventually removed because it seemed to be accelerating casing corrosion. As a result of this problem (and possibly some casing material issues), many of the Dow Moore wells appear to have an advanced magnitude of corrosion although corrosion rate has diminished.

5.4.15.1 Condition Methodology

Failures of well assets are generally caused by corrosion of the well casings, resulting in loss of containment. Corrosion can also be external, caused by highly corrosive geological layers which exist above the storage reservoir formation through which the casing(s) must penetrate. As corrosion progresses, there is widespread wall loss over time and previously insignificant defects become more pronounced. Back-off repairs are sometimes possible but eventually, casing corrosion below the first 20 meters becomes so extensive that abandonment is prescribed by code. For newer wells, the number of well casing defects requiring action is expected to be low.

Well condition is assessed directly by the Storage Downhole Integrity Management Program (SDIMP) using vertilogs (similar to in-line inspection tools used for pipelines). Condition assessments for wells are based on abandonment criteria prescribed by *CSA Z341* and the *Oil, Gas, and Salt Resources (OGSR) Act*.

A simple condition model was developed for Storage wells that employs the assessed condition of wells and applies the following influencing factors:

- Relined wells have experienced intolerable corrosion and have been repaired by installing a new, smaller diameter casing concentrically inside the old casing. The annular space between the original production casing and the new relined casing is filled with cement. These relined casings have demonstrated a high failure rate (loss of containment, albeit with very low flow rate) due to cracking of the cement in the annular space. All relined wells are expected to experience an elevated probability of failure.
- The number of well casings has been deemed by SMAs to have an increased PoF. Modern well designs use three casings with cement in each annular space. Several wells in the Sarnia area and all wells at Crowland were constructed to an older design standard using two casings. Fewer casings are expected to result in a greater PoF.
- Cement between casings provides a seal to prevent gas migration through the annulus between casings. Without cement, flow from the reservoir would be able to migrate through the annular space in the event of a failure. Cement also provides corrosion resistance to affected casing surfaces. Lack of cement between casings is expected to increase PoF. All well designs at Crowland are constructed without cement between the casings.
- Casing material appears to be correlated to probability of failure. Specifically, the casing material used at Dow Moore (DOW casing employs N80 material specification) is correlated with an increased corrosion rate. Higher corrosion rates are expected to yield increased PoF.

Condition assessment is based on directly measured vertilog data. This approach is limited in that condition does not consider factors beyond corrosion, such as microannulus leaks. Instead, the condition assessment of each individual well considers:

- Previous condition from the most recent vertilog inspection
- Rate of corrosion growth over multiple vertilog inspections
- Accuracy of vertilog inspection technology used during previous inspections.

A preliminary attempt to estimate well corrosion growth rate was undertaken, with the intention of extrapolating the growth rate and predicting the point in time where a well is expected to exceed prescribed corrosion tolerances. This attempt to forecast well abandonment timelines did not include the wells at Crowland.

Condition is described using the Asset Health Index shown below.

HEALTH INDEX	PROBABLE TIME TO REPLACEMENT
HI1	Greater than 40 years
HI2	Within 40 years
HI3	Within 25 years
HI4	Within 10 years
HI5	Within 5 years

5.4.15.2 Condition Findings

Typical corrosion growth rates can be used to extrapolate expected end-of-life for each individual well. The preliminary evaluation of condition is presented in **Figure 5.4-14**.

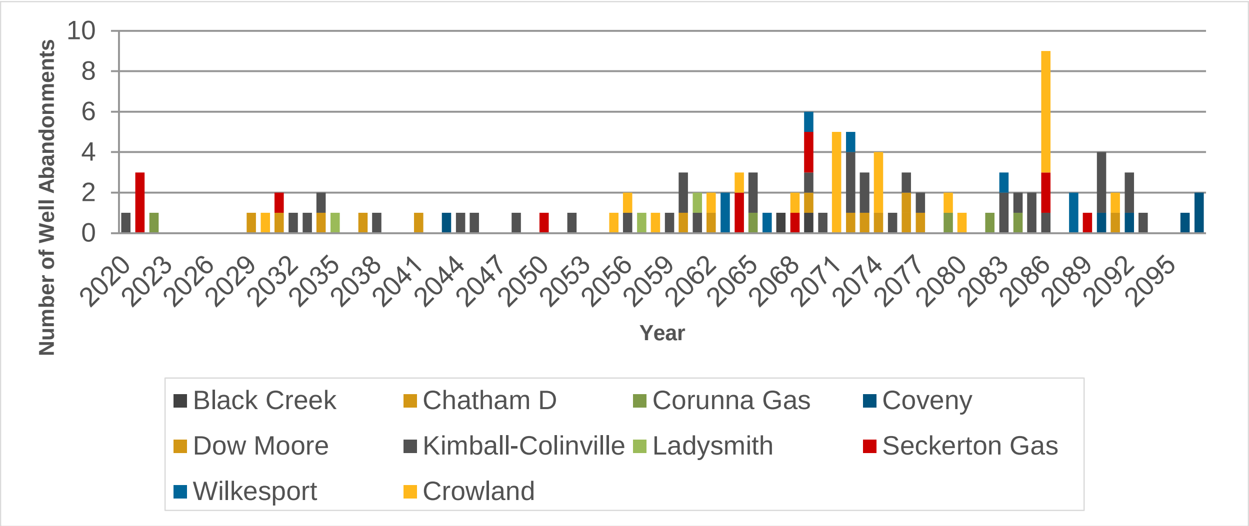


Figure 5.4-14: Estimated Well Abandonments by Year

This assessment, based only on corrosion threats, is transformed into the Health Index categorization established by the Asset Health Review program. Resulting well condition is shown in **Figure 5.4-15**.

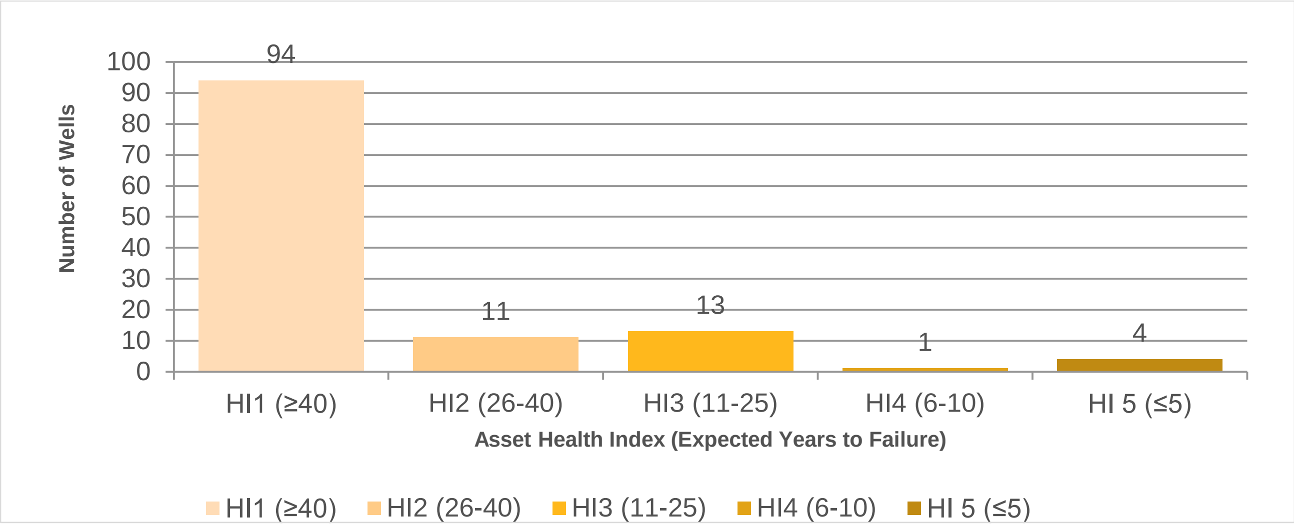


Figure 5.4-15: Asset Health Index - Year 2017 Storage Wells

Using the forecasted abandonment year, the condition of existing storage well assets is generally adequate (HI3) or better. Note that three of the HI5 wells shown above are scheduled for abandonment because they are expected to develop microannulus leaks.

A full Asset Health Review condition model of wells is expected to show that Crowland wells are the exception. Crowland is described by SMAs to have a condition of HI4 when considering factors beyond corrosion. The two casing design, creates a situation where a single cement layer separates the inner casing from surrounding rock, and the cement employed is unsuitable for sulphur-rich environments. Most wells at Crowland do not possess a suitable master valve and wellhead and have only two casings. Many Crowland wells are re-lined, further justifying replacement. Replacement of well assets, especially at Crowland, is expected to be a significant capital request within the scope of the 10-year Asset Management Plan.

Fines and Precipitation of Scale: Migration of fines and precipitation of scale in the reservoir rock near the wellbore occurs each year. As the gas moves in and out of the storage formation, fine rock particles migrate through the formation and plug the pathways from the storage reef to the well. This reduces the permeability and porosity at the wellbore face and thereby reduces the deliverability capability of the well. Analysis suggests reservoir performance declines by about 0.75% per year on average, due to wellbore damage from fines and scale.

Lost and Unaccounted for Gas (LUF): Most of the storage reservoirs are surrounded by a very low-porosity crystalline structure, referred to as the A-1 region. These A-1 zones are considered a potential means by which gas may become trapped, artificially increasing the perceived amount of LUF. Interpretations of the latest reservoir simulations indicate that the A-1 region may extend beyond the geographical edge of some Designated Storage Areas.

Well Accessibility: Many wells are located in areas where personnel access is limited. Often the subject wells are located in the middle of an agricultural field and laneways were not installed at the request of the landowner. During normal maintenance activities, personnel are required to access these wells. During the winter, maintenance activities expose personnel to very difficult physical conditions.

Observation Wells: Observation wells at PDOW and PCOR have been recently abandoned due to corrosion concerns and require replacement. These wells are critical for reservoir inventory management.

5.4.15.3 Risk and Opportunity

Currently, measured condition data is obtained through the SDIMP. The SDIMP is managed by Storage stakeholders, is well established and shows a moderate expectation that well abandonments will be required over the duration of the 10-year period.

Safety Risk: If unmitigated, risks related to safety are generally expected to increase slowly due to continued corrosion influences. Wells exceeding corrosion tolerances will be abandoned as prescribed by code, such that significant safety risks are proactively reduced. Risk modelling considers the possibility of injury to the public and personnel. Wells have a major influence on public and employee safety risk.

- Wells have the potential to cause injury during a loss of containment event.

Financial Risk: If unmitigated, loss of containment risks are generally expected to increase slowly due to continued corrosion influences. Risk modelling considers loss of containment and damage to infrastructure. However, PoF is generally very low due to the low risk tolerance built into the governing technical code.

- Wells represent significant financial risk to EGD and regulated customers. Unexpected well failures carry a large cost of replacement and lost product.

Customer Satisfaction Risk: Well abandonment is a safety and financial risk mitigation of the existing wells. However, once an existing well is abandoned the flow capacity of the associated reservoir is reduced. Reduced reservoir performance creates a customer satisfaction risk - reduced system performance may reduce storage deliverability, which could require that gas supply be obtained from other potentially more expensive sources. Risk reduction is achieved by drilling new wells to replace those that have been abandoned. A large component of customer satisfaction risk is related to reservoir performance. Well failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply, requiring gas to be obtained from other potentially more expensive sources. A single well failure can shut down an entire reservoir for a long duration.

- Operational reliability consequences of an unexpected well failure can be significant for regulated customers. Such a failure could cause an increase in gas supply, requiring gas to be obtained from other potentially more expensive sources to regulated customers, as a portion of required gas would need to be sourced from other suppliers for the entire duration of the event. Consequences can be moderate because an outage from a single reservoir would still allow remaining reservoirs to operate.

Well-related activities are targeted to reduce or explain LUF. LUF is a contributor to gas supply costs to regulated customers. Activities intended to reduce LUF would provide a positive benefit to regulated customers.

5.4.15.4 Strategy

Current indications are that Well asset condition is HI1 to HI3, with the exception of wells experiencing actual microannulus leaks or an increased risk of microannulus. Life cycle management strategy involves the continued direct measurement of well condition for signs of corrosion. Direct measurement is the most effective way to determine well condition.

The strategies for wells are as follows:

- Install A-1 observation wells help to validate reservoir simulation models to verify the integrity of the reservoir boundaries and demonstrate the relationship of low permeability zones to LUF.
- Implement a program to periodically inject an acid solution to break down fines and precipitation of scale at the wellbore face (acidization).
- Implement a program to install new and replace existing laneways and roads to provide adequate access to wells.
- Implement a Well Casings program to address corrosion in the top two joints of the production casing.
- Install net new wells, complete with associated gathering piping and temporary filtration to restore reservoir deliverability.
- Reduce number of Crowland wells that were constructed with cement unsuitable for a sulphur-rich environment and replace with new wells.
- Install new reservoir observation wells to comply with *CSA Z341* requirements.
- Implement a program to purchase specialized wells tools required for continued maintenance of the wells.

EGD continues to enhance its understanding of asset health and life cycle cost for wells, which will inform future capital investment requirements.

5.4.16 Master Valves, Wellheads, and Emergency Shutoff Valves (ESV)

Master valves are the last isolation point of a well that separates the geological formation from the environment. A wellhead is a component that interconnects the master valve with the well casing. Master valves have been viewed in the context of whether they seal when closed. If not, a possible uncontrollable loss of containment at the well may occur. Master valves are a repairable sub-asset type because they are always located above grade (i.e., easily removable) and are designed to be disassembled for easy replacement of wear items.

Replacement of master valve assets is normally driven by repair costs, obsolescence, or a change in performance requirements. In many cases, repair can be as expensive as replacement. Removal of the master valve for any reason is an expensive undertaking because the well must be temporarily plugged. Many master valves have been replaced since 2005, so the relative age of these replaced assets is low. Master valves are inspected monthly for gas leakage to atmosphere.

Master valve age distributions are shown in **Figure 5.4-16**. Age distribution is depicted as at the end of 2016 and excludes 24 master valves at Crowland.

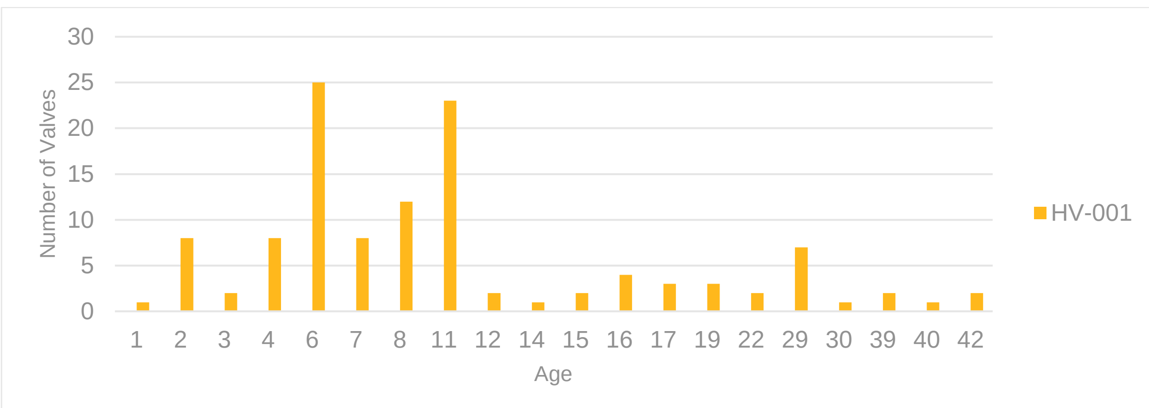


Figure 5.4-16: Master Valves – Age and Population

Emergency Shutoff Valves (ESV) are installed above the master valve on high flow wells. High flow wells are typically Horizontal wells, but can also include wells with high enough flow to create sufficient failure risk. ESVs are Fail Closed valves that are manually opened, but will close automatically in the event of a well fire. ESVs are very new and there is no failure history. ESVs will eventually be viewed in the context of whether they seal when closed once there is sufficient service history. Age distributions are shown in **Figure 5.4-17**. Age distribution is depicted as at the end of 2016.

Figure 5.4-17: ESVs – Age and Population

5.4.16.1 Condition Methodology

Master Valves and Wellheads

The assessment of master valves and wellheads have yet to progress to the point where a condition model can been implemented. SMA input is the primary means by which master valve and wellhead condition is estimated.

The focus of master valve condition is the quality of the seal when the valve is in the closed position. A poor quality seal results in gas leakage that could affect health and safety during maintenance activities and effectiveness of isolation during an emergency event. Master valves are manually actuated, and are not activated remotely. A master valve that does not seal properly can create a safety risk of workers operating the valve, or workers relying on the valve to fully seal.

ESVs

The condition of ESVs are determined by SMA input. ESV valves are a repairable sub-asset type because they are always located above grade (i.e., easily removable), normally installed with sufficient isolation to allow removal without significant system upset, and are designed to be disassembled for easy replacement of wear items. Replacement of ESV valve assets is normally driven by repair costs, obsolescence, or a change in performance requirements. In many cases, repair can be as expensive as replacement. Installation of ESV valves began in 2014, meaning that the relative age of these assets is very low.

5.4.16.2 Condition Findings

Master Valves and Wellheads

The condition of master valve actuators was determined by SMAs to generally be very good. Condition of master valve seal condition was also estimated with SMA input to be fair to good. SMA input indicates that the condition of ESV assets is generally very good, and will require minimal attention over the course of the 10-year Asset Management Plan.

It is recognized by SMAs that Crowland represents significant master valve and wellhead containment risk. Master valves at Crowland are ball valves of a type normally used in pipelines. Ball valves are connected to the well casings with a flange assembly. This configuration was installed prior to establishment of the *CSA ZA341* code which now governs reservoirs. Casing vents are not available to determine if there is any pressure build-up between casings. Inspection of casing vents is normally used to infer leakage. The physical condition of these assets appears stable, but represents a larger than normal probability of failure (i.e., loss of containment).

With the exception of Crowland, the calendar age of master valves is relatively low. Wellhead and master valve replacements for 16 PCRW wells are expected within the timeframe of the 10-year Asset Management Plan. Abandonment of eight additional PCRW wells is also expected in the 10-year period of the Asset Management Plan.

ESVs

SMA input indicates that the condition of ESV assets is generally very good, and will require minimal attention over the course of the 10-year plan.

5.4.16.3 Risk and Opportunity

Master Valves and Wellheads

The consequence of master valve or wellhead failures is dominated by the gas cost impact to customers and safety. Customer satisfaction risk associated with a repairable failure of a master valve is diminished by the time of year and weather severity. Safety risks tend to be steady throughout the annual turnover cycle. If unmitigated, master valve risks are generally expected to increase over time because valve seal quality will continue to deteriorate over time.

Safety Risk: Master valves and wellheads have a moderate impact on public and worker safety. Regular inspection of the wellhead and master valve seals, coupled with proactive replacement when needed, will reduce the risk of unplanned failure resulting in a significant outage. Master valve and wellhead condition has a direct influence on safety risk to the public and employees. Master valves are the only separation of the reservoir from surface facilities, and their failure carries significant consequences. Typically, master valves are equipped with soft seals that are vulnerable to wear.

- Inadequate gas containment by valves during an emergency situation has the potential to injure workers and the public if valve seals fail to fully isolate.
- Leaking master valves can also compromise worker safety during maintenance operations by unintentionally exposing workers to the risks of asphyxiation, fire, and mechanical energy release.

Financial Risk:

- Master valves are the only separation of the reservoir from surface facilities, and their failure carries significant consequences. Failure of master valves and wellheads can result in loss of Storage deliverability and performance, and incremental loss of product during a loss of containment event from other sub-assets.

Customer Satisfaction Risk: A large component of customer satisfaction risk is related to the operational reliability of the master valves and wellheads.

- Unplanned failures, especially during late season withdrawal, can have a highly disproportionate impact on gas supply costs. A single master valve or wellhead failure can shut down an entire reservoir – depending on failure severity.
- Master valve wellhead process safety risks focus on the ability of a master valve to seal in an emergency situation. Master valves are the only separation of the reservoir from surface facilities, and their failure carries significant consequences. Master valve or wellhead failure could result in shutting in an entire reservoir, thereby increasing gas supply costs to secure alternate supplies.

ESVs

Safety Risk: ESV condition has a direct influence on safety risk to the public and employees. ESVs provide fail safe isolation of the reservoir from surface facilities, hence can limit injury to employees and the public during a well failure. Typically, ESVs are equipped with soft seals that are vulnerable to wear.

- Inadequate gas containment by ESVs during an emergency situation has the potential to injure the public and workers if the valve seals fail to fully isolate.
- From a process safety perspective, installation of new ESVs is a regulatory compliance issue, meaning that risk reduction may be low, but is still required to satisfy code requirements.

Financial Risk: ESVs provide fail safe isolation of the reservoir from surface facilities, hence can limit secondary damage, repair cost, and lost product related to a well failure.

Customer Satisfaction Risk: ESV process safety risks focus on the ability of the valve to seal in an emergency situation. ESVs provide fail safe isolation of the reservoir from surface facilities, hence can limit secondary damage and outage durations related to a well failure. Reduced outage durations reduce the risk of increased gas supply costs related to securing alternative gas supplies. In addition to operational reliability and process safety risks, customer satisfaction for Storage is strongly linked to financial risk because financial risks can affect gas supply costs, and therefore costs to regulated customers.

5.4.16.4 Strategy

Master Valves and Wellheads

Based on SMA input, replacement of master valves and wellheads, mainly at Crowland, is proposed. Ongoing work through the Asset Health Review is expected to provide additional analytical support related to valve health.

ESVs

Replacement of ESV assets, based on condition, is not anticipated at this time. The strategy for ESVs is to:

- Purchase a portable Methanol injection system to mitigate freeze-ups
- Install electrical supply to existing ESVs that employ solar panels
- Continue the installation of ESVs for remaining horizontal wells

5.4.17 Methane Emission Reductions

"*As part of the Pan-Canadian Framework on Clean Growth and Climate Change, the Government of Canada reaffirmed its commitment to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025. Methane is a potent greenhouse gas (GHG) that is 25 times more powerful than carbon dioxide and methane emissions make up about 15 percent of Canada's total GHG emissions. The oil and gas sector is the largest contributor to methane emissions in Canada. In April 2018, Environment and Climate Change Canada (ECCC) published federal methane regulations to deliver on this commitment. ECCC has consulted extensively with provinces, territories, industry, environmental organizations and Indigenous peoples to develop robust and cost-effective regulations. These outcome-focused regulations apply to upstream oil and gas facilities, which are responsible for extraction, production, processing and transportation of crude oil and natural gas. The requirements target two key methane sources: fugitive emissions, which are unintentional leaks from equipment leaks, and venting emissions, which are intentional releases of methane into the air.*" [Environmental and Climate Change Canada, Government of Canada]

The applicable regulations for EGD are outlined below:

- **Facility Venting (by 2023)**: Facility venting limit of 15,000 m^3/year (excluding: emissions from liquids unloading, blowdowns, glycol dehydrators, pneumatic devices, start-up and shutdown of equipment, and well completions, as well as those arising due to emergency situations)
- **Compressor Seals / Rod Packing (by 2020-existing, 2023-new)**: Large (>5MW) centrifugal compressors will have a limit of 0.68 m^3/minute/compressor, small (<5MW) centrifugal compressor will have a limit of 0.34 m^3/minute/compressor, reciprocating compressors will have a limit of 0.023 m^3/minute/compressor cylinder; new compressors will no longer be required to conserve emissions, but to meet a limit of 0.14 m^3/minute/seal for centrifugal compressors and 0.001 m^3/minute/rod packing for reciprocating compressors. There are exemptions for very small and low use compressors.
- **Leak Detection and Repair – LDAR (by 2020)**: Facility must be inspected three times a year with at least 60 days between inspections. Any leaks found should be repaired with 30 days unless an extension is granted. An alternative LDAR program can be proposed with at least one inspection per year, if equal effectiveness can be shown.

5.4.17.1 Risk and Opportunity

New methane emissions reduction infrastructure will become integral assets required for Gas Storage operations. Approximately 25% of annual gas volume and 55% of peak flow rate delivered into the EGD gas distribution system is sourced from EGD's Storage facility. Finalized scope of methane emissions reduction regulations became available in April 2018. Currently, the scope of methane emission reduction asset upgrades is not yet well understood - evaluation of solution options is expected by the end of 2018. A significant expenditure is anticipated over the duration of the next 10-year period.

Safety Risk: Methane emission reduction assets are not expected to have a major influence on public and employee safety. Solution options being considered generally involve gas compressor instrumentation and/or new auxiliary piping to the maintenance flare.

Financial Risk: Failure to comply with the new methane emissions reduction regulations could result in fines for EGD.

Customer Satisfaction Risk: Failure to comply with the new methane emissions reduction regulations could result in regulatory orders for EGD, potentially limiting the use of compression equipment until compliance is achieved. Restricted use of compression equipment could reduce deliverability and rigger the need to secure gas from alternate sources, at additional gas supply cost. Compliance with environmental regulations is also considered a reduction in customer satisfaction risk.

5.4.17.2 Strategy

EGD's current strategy to address recent regulations is as follows:

- Develop a leak detection program for gas storage facilities to review new regulations, determine infrastructure inspection and frequency requirements, analyze technologies that can be used for detection, analyze costs associated with contracting out inspection services or purchasing/installing equipment and training staff, and field testing as required. Once the system is established, subsequent annual costs will be allocated to Operations & Maintenance.
- Continue to investigate rod packing emissions to determine appropriate mitigation measures to comply with new regulations.
- Continue to investigate and remediate other potential sources of methane emissions to minimize facility venting, which could include activities such as installing metering at maintenance flares, installing new yard auxiliary pipelines to collect currently emitted gas, etc.
- Continue to understand the operational and asset requirements needed to adhere to the federal methane regulations.
- Understand and follow regulatory developments as the effective date for new requirements approaches.

5.4.18 Storage Capital Expenditure Summary

The summary of projects and programs under the Storage asset class accounts to $180M from 2019 to 2028, as summarized in **Table 5.4-8**. The Storage capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.4-8: Storage Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Compressor Equipment	24,066	27,870	27,589	10,513	10,999	5,953	4,934	3,299	2,489	2,660	120,370
SCOR Sustainment	17,184	24,808	27,298	9,466	7,387	5,166	4,472	2,811	1,914	1,815	102,321
SCOR Renewal Study	2,500	-	-	-	-	-	-	-	-	-	2,500
Carbon Capture	1,701	2,505	-	-	-	-	-	-	-	-	4,205
Compressor Equipment <$2M	1,441	558	291	1,047	3,612	787	462	488	575	845	10,104
Integrity Initiatives	577	771	1,040	735	728	851	1,075	744	1,113	1,134	8,767
ILI Retrofit	477	671	940	635	628	751	975	644	1,013	1,034	7,767
FIMP	50	50	50	50	50	50	50	50	50	50	500
Records Integrity	50	50	50	50	50	50	50	50	50	50	500
Field Lines	2,079	1,343	498	1,006	1,496	930	398	3,509	1,225	225	12,709
Well Loops-Adjust	71	71	71	71	71	71	71	71	71	71	710
Leaking Valves	462	462	307	307	307	154	154	154	154	154	2,615

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Field Lines <$2M	1,546	810	120	628	1,118	705	173	3,284	1,000	-	9,383
Wells and Well Equipment	7,246	3,976	3,298	2,143	1,167	3,749	1,927	11,098	739	1,403	36,746
Horizontal Wells	3,976	2,395	-	-	605	2,395	-	-	-	-	9,371
Observations Wells	2,254	688	2,724	1,190	-	-	-	-	-	-	6,856
Wells Upgrade	-	-	-	-	-	443	1,290	9,914	-	-	11,648
Well Casing Replacement	400	400	400	400	400	400	400	400	400	400	4,000
Wells Acidize	326	391	-	391	-	391	-	391	-	391	2,280
Wells and Well Equipment <$2M	290	102	174	162	162	120	237	393	339	612	2,591
Measurement and Regulating Equipment	14	14	14	729	209	14	14	14	79	14	1,118
Storage Total	**33,981**	**33,974**	**32,440**	**15,126**	**14,599**	**11,497**	**8,349**	**18,664**	**5,646**	**5,435**	**179,710**

Refer to **Section 6.3** for projects with expected spend that are not included in the capital summary.

5.5 CUSTOMER ASSETS

Customer Assets are the components of the distribution system that regulate system pressure, ensure low pressure delivery to the customer, and measure gas consumption. Safety is the paramount role of these assets, as the regulation system within it is the last line of defense for over-pressure to the customer.

5.5.1 Customer Assets Objectives

The Customer Assets asset class includes: Measurement Systems, Regulation, Safety, Device and Piping Systems, Below-ground and Internal Piping Systems, and Customer-owned Systems. The asset class is accountable for the installation, maintenance and remediation of assets downstream of the winglock and upstream of and including the meter. For Customer-owned Systems that are downstream of the meter, the asset class is accountable for inspection at the time of initial installation and after re-introduction of gas. Maintenance and remediation of these assets are the responsibility of the customer. The asset class breakdown is summarized in **Figure 5.5-1**.

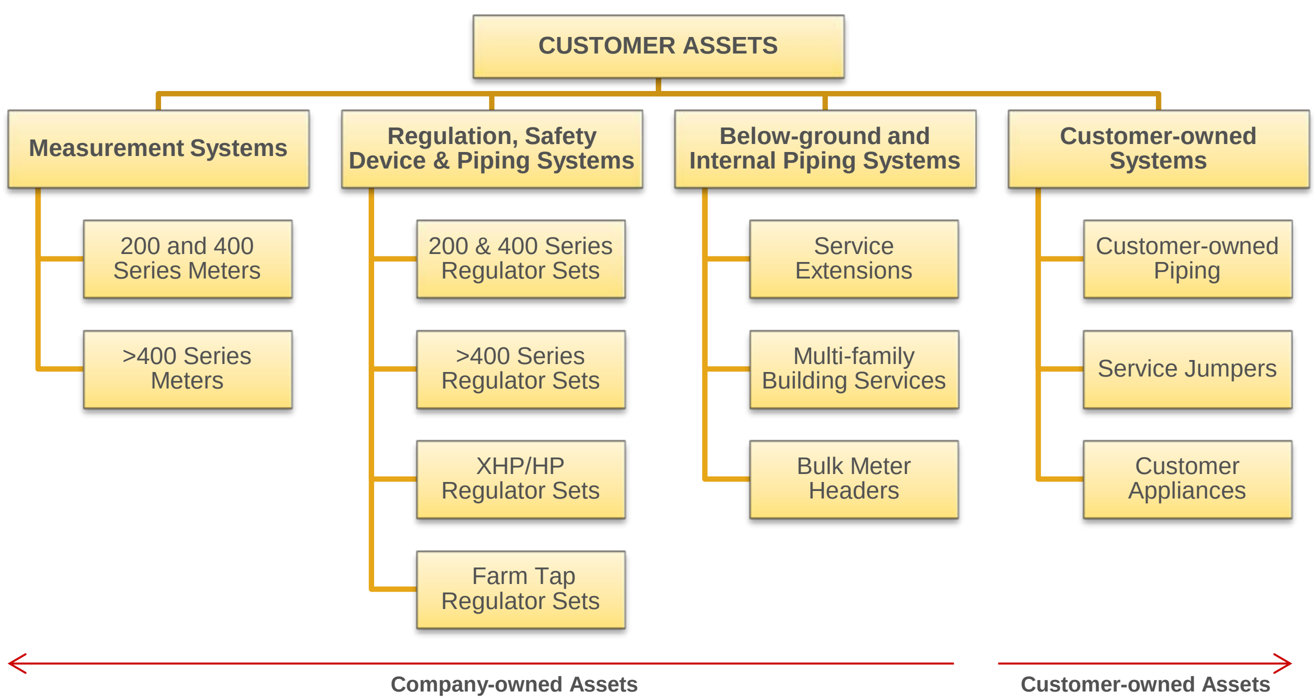


Figure 5.5-1: Customer Asset Classification

The objectives for the Customer Assets asset class are listed in **Table 5.5-1**.

Table 5.5-1: Customer Assets Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
System Integrity and Reliability	Install and maintain assets to meet or exceed standards for customer safety, compliance and operational effectiveness.	• QA/QC closeout rate • Number of TSSA regulatory non-conformances • % completion of compliance work
	Ensure the safe and reliable delivery of natural gas to end users.	• Customer Safety and Compliance o % of on-time emergency response • Customer Satisfaction Survey o Field Service Index o Appointments Met metric
	Utilize cost, risk and performance information to drive asset-related decisions.	• Risk mitigated and LRROI • QRA completion %
	Continuously evolve the understanding of condition and risk associated with customer assets.	• Material Fault Management o On-time Fault Classification o On-time completion of corrective actions • Regulator Data Capture metric • Failure Classification Usage metric
	Ensure accurate metering of customer gas consumption.	• Completion of MXGI replacements

To achieve these objectives, asset investment decisions are governed by the Life Cycle Management policies as outlined in **Table 5.5-2**.

Table 5.5-2: Life Cycle Management for Customer Assets

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Design the installation of customer assets to: - Ensure worker and public safety - Ensure regulatory compliance - Meet current and future demand requirements - Reduce risk to the lowest practicable level - Ensure critical components and systems have multiple layers of failure protection - Minimize environmental impact - Ensure components can be made safe in a reasonable period of time. - Minimize future maintenance needs • Procure materials to meet or exceed codes, standards and policies • Install customer assets to meet or exceed codes, standards, designs, and procedures for safe and reliable operations • Create asset records to meet or exceed standards, policies and procedures that are traceable, verifiable, complete, and correct.
Utilize	• Operate the distribution system to: - Ensure worker and public safety - Meet or exceed compliance standards and established procedures - Meet current demand - Ensure reliable gas delivery - Minimize end user disruption

LIFE CYCLE STAGE	ACTIVITIES
	- Utilize the assets in the most cost effective manner - Extend asset life • Monitor the performance and use of customer assets to inform future life cycle decisions and to ensure correct measurement of customer usage • Inspect downstream piping and appliances to ensure safe operations by the customer
Maintain	• Maintain integrity of assets to minimize loss of containment, extend asset life and ensure compliance with codes, standards and established procedures • Maintain assets and safety controls to avoid over pressure or delivery outage • Maintain asset information to meet the standards set out by EGD • Determine probability and consequence of failure to inform maintenance and repair programs • Maintain competency levels to ensure work is performed by qualified and competent workers • Evaluate effectiveness of maintenance and inspection programs to ensure effective risk reduction to the lowest practicable level
Renew/Retire	• Determine probability and consequence of failure to inform renewal decisions • Develop proactive renewal programs for assets that are nearing end-of-life (informed by data and tacit knowledge) • Retire assets using a process that meets or exceeds codes and standards

5.5.2 Customer Assets Inventory

Customer Assets include all assets downstream of the winglock valve and upstream of the meter outlet. These customers can be grouped into the following categories based on similar characteristics:

- Apartment
- Commercial
- Industrial
- Residential (low density)

Over 90% of customers are residential, with the remaining being mostly commercial.

CUSTOMER TYPE	COUNT
Apartment	7,445
Commercial	153,007
Industrial	6,181
Residential	1,990,032
Total	2,156,665

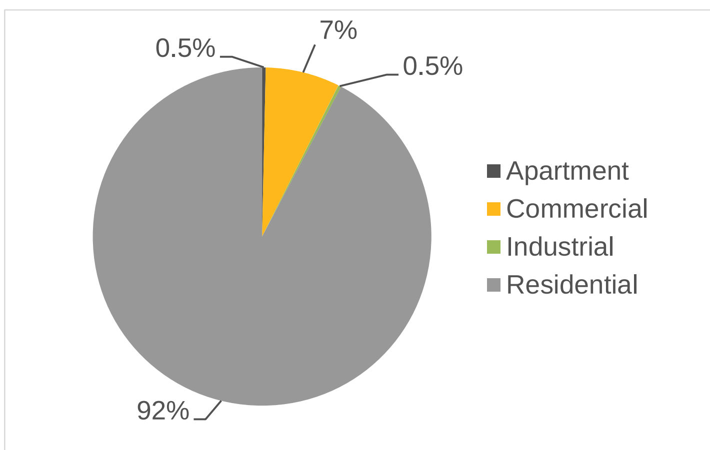


Figure 5.5-2: Customer Type Statistics (Dec 2017)

With 2.1 million customers requiring low pressure delivery, understanding and maintaining the health of these assets is a critical part of providing safe and reliable gas delivery. These assets are EGD-owned. All assets downstream of the meter outlet are customer-owned.

Customer Assets are comprised of four asset subclasses:

- Measurement Systems
- Regulation, Safety Device, and Piping Systems
- Below-ground and Internal Piping Systems
- Customer-owned Systems

Each Customer Assets asset subclass has unique characteristics and the management of each is tailored to ensure the safe and reliable delivery of natural gas.

Measurement Systems: Measurement systems track customers' consumption of gas. As these systems directly link to customer billing, they are subject to a stringent replacement program overseen by Measurement Canada.

Regulation, Safety Devices, and Piping Systems: These systems regulate the delivery of gas at a pressure appropriate for customer-owned gas-firing appliances and are the last line of defense for over-pressure protection. There are three typical safety devices used in Customer Assets - internal relief valves, external relief valves, and over-pressure cut-offs.

With the exception of customers off low pressure mains, each customer location has at least one regulator and one over-pressure safety device installed to prevent unsafe pressures from entering the premises in the event of a malfunction. These systems include above-ground piping between the winglock and meter and components required for regulation.

This asset subclass is comprised of the following components:

- **Regulators** reduce natural gas pressure to safe operating limits and control its flow based on customer demand. Regulators typically have an internal relief valve designed to be closed but will open if the primary regulation function is malfunctioning. Customer Assets are regulated to deliver low pressure, typically at 7" wc.

- **Safety Devices** prevent downstream over-pressure and are the last line of defense to prevent potentially hazardous conditions.

- **Piping** on regulator sets refers to any of the above-ground piping between the winglock and the meter outlet.

Below-ground and Internal Piping Systems: These systems are located upstream of inside meters and refer to piping running below grade or piping running inside a building.

EGD owns a type of below-ground asset called a Service Extension. Service extensions are below-ground pipe between the regulator outlet and the meter inlet (not to be confused with jumpers owned by the customer since they are downstream of the meter set). Within this asset class, EGD takes all reasonable efforts to avoid below-ground piping since it provides new hazards and requires costly maintenance. Internal piping is typically found in multi-family buildings. This piping runs between the regulation and piping system located outside to meters inside the garage or in individual units.

Customer-owned Systems: Piping and assets downstream of the meter are customer-owned. Although EGD does not own these assets, *O. Reg. 212/01* requires an inspection of all installations upon initial connection to the gas supply or during the reintroduction of gas. In addition, EGD continues to inspect customer assets as part of a quality management program. By meeting these requirements, EGD helps to ensure the safe delivery of natural gas. As a last resort, EGD can terminate the natural gas supply if the customer fails to remediate any identified critical safety issues.

A typical arrangement of these assets is illustrated in **Figure 5.5-3**.

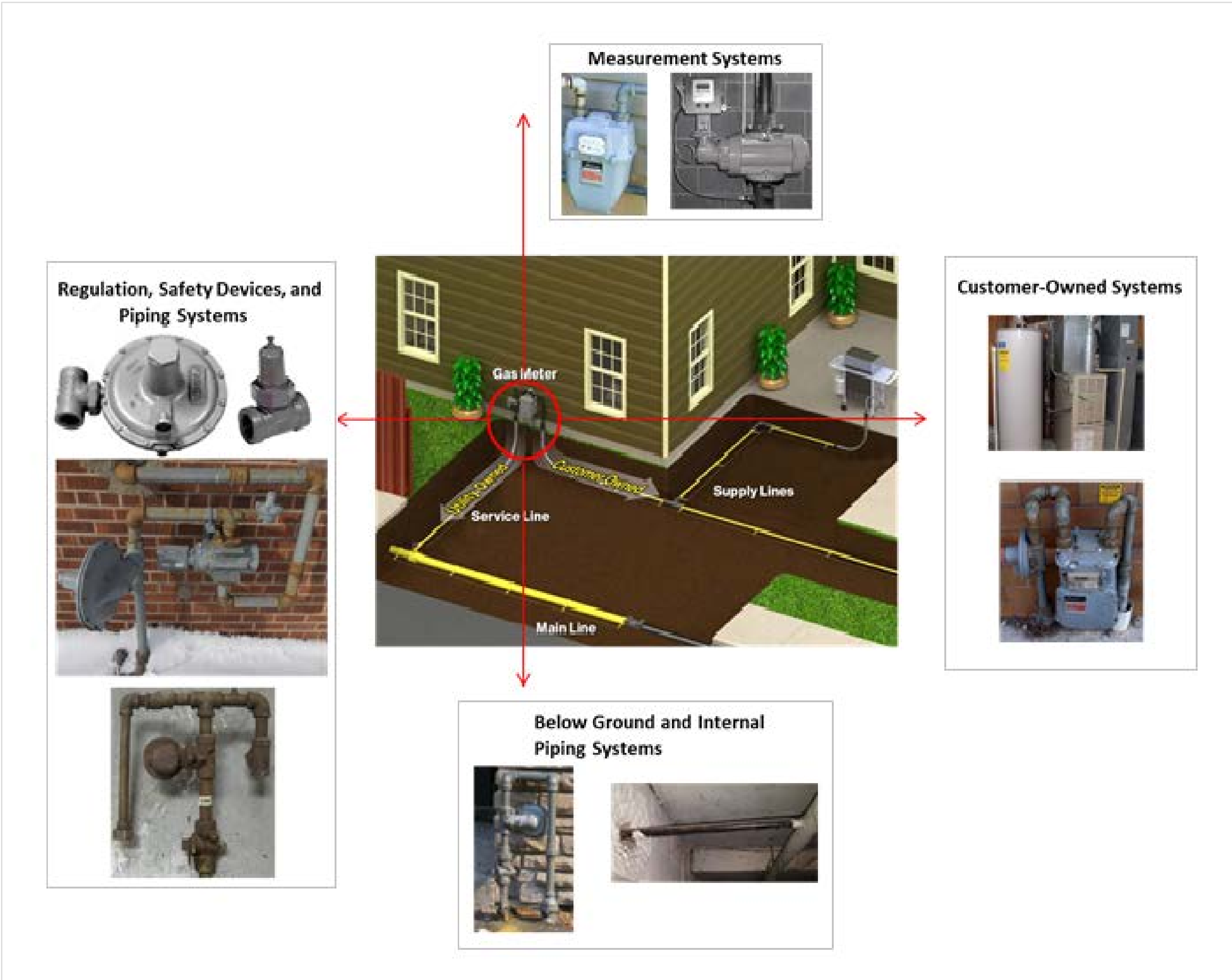


Figure 5.5-3: Customer Assets Illustration

Table 5.5-3 lists the inventory details for the Customer Assets subclass.

Table 5.5-3: Customer Asset Class Inventory

ASSET SUBCLASS	QUANTITY
Measurement Systems[*]	**2.20M**
200 And 400 Series Meters	2.14M
>400 Series Meters	63,622
Regulation, Safety Devices, And Piping Systems	**2.08M**
200 And 400 Series Regulator Sets	2.03M
>400 Series Regulator Sets	47,192
XHP/HP Regulator Sets	27,114
Farm Tap Regulator Sets	10,259
Below-ground And Internal Piping Systems	**17,222**
Service Extensions	14,240
Multi-Family Building Services	2,900
Bulk Meter Headers	82
Customer Owned Systems	N/A

[*]*Inclusive of meters used on Sales Stations.*

5.5.3 Customer Assets Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Measurement Systems • 200 and 400 Series Meters • >400 Series Meters	Dependent on meter type. Between: • 18-24 years old • 10-20 years old	**Meter Exchange Government Inspection (MXGI) Program:** This program is designed to replace meters before they fail. Meter seal life (and extensions) is based on sampling and testing to ensure Measurement Canada specifications are maintained. **Non-program:** Non-program meters that fail before the prescribed maximum service life are discovered during emergency calls or customer-initiated work. In most years, the number of meters exchanged outside of the program represents less than 1% of the population.	Failing to remove failed meters from service carries penalties under the *Electricity and Gas Inspection Act*, leading to: *Financial Risk:* Monetary penalty for non-compliance to government mandated programs. Monetary loss due to shortened life cycle of meters, related to accreditation loss. In addition, there is a financial opportunity to remove groups of meters that have been sampled multiple times with the availability of short extensions remaining.	The maintenance strategy for measurement systems are: • Meters are maintained and replaced per the Measurement Canada-prescribed regulatory program. • Meters are in scope for indoor and above-ground header leak surveys.	EGD's replacement/renewal strategy for measurement systems is through: **MXGI Program:** Continue with the MXGI program to meet or exceed regulatory compliance. Proactively replace meters as per Measurement Canada's performance testing standards. **Non-program:** Reactively respond to customer leak or other service interruption calls for non-program related meter exchanges. In addition, EGD continues to use data to project MXGI replacement volumes with a focus on leveling volumes over future years. Meters have a complete set of data that includes: quantity, age, make, size, location, and historical performance. The completeness of this data enhances the optimization of the life cycle strategy.
Regulation, Safety, and Piping Systems • 200 and 400 Series Regulator Sets	Dependent on meter and regulator type: between 20-30 years old. (~15% of the population is over 20 years old.)	Failure history and trending indicates that the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. Failure rate is 0.14% of total population.	Majority of customers are connected to the distribution system through 200 and 400 series regulator sets. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impact Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for 200 and 400 series regulator sets is to proactively maintain and replace units in conjunction with EGD's MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's proactive replacement/renewal strategy for replacing 200 and 400 series regulator sets is through: **Regulator Exchange Program:** Exchanging regulators during MXGI inspections prevents the population from reaching the wear-out phase. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Other compliance issues are corrected as part of MXGI work. Regulators are opportunistically replaced if found to be 20 years or older.
Regulation, Safety, and Piping Systems: • >400 Series Regulator Sets	Dependent on meter and regulator type: between 20-30 years old. (>50% of the population is over 20 years old.)	>400 series regulator sets have an older population compared to 200 and 400 series regulator sets. More than half of these regulator sets have regulators older than 20 years. In addition, a sample survey identified sites not adhering to current installation specifications.	>400 series regulator sets account for 2% of all EGD regulator sets and are predominantly used in commercial, industrial, or higher density residential premises. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for >400 series regulator sets is to adhere to a proactive and targeted inspection and remediation program, ensuring installation meets current code requirements. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's proactive replacement/renewal strategy for replacing >400 series regulator sets is through: **Targeted Inspection and Remediation Program**: Continuation of a targeted inspection program (commenced in 2017) to identify site-specific issues and remediate as necessary to ensure regulator sets are brought up to current installation standards. Similar to 200 and 400 series regulators, >400 regulators are opportunistically replaced if found to be 20 years or older.
Regulation, Safety, and Piping Systems: • XHP/HP to LP Delivery Regulator Sets	Dependent on meter and regulator type: between 20-30 years old.	78% of sites have some degree of corrosion. Failure history and trending indicate the wear-out phase for regulators associated with 200 and 400 series meters is unlikely to occur before 30 years of age. First cut regulators were not historically replaced at the same time as second cut regulators, as per current installation standards. Approximately 65% of sites not compliant to installation specifications have been remediated.	Approximately 1% of the total regulator set population is XHP/HP. These regulator sets present a higher consequence due to higher pressures managed by two pressure cuts. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for XHP/HP to LP delivery regulator sets is to proactively maintain and replace units in conjunction with EGD's MXGI program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's proactive replacement/renewal strategy for replacing regulators is through: **Inspection and Remediation Program**: Continuation of the targeted regulator remediation program to address the remaining 35% of sites with identified compliance issues within three years. **Regulator Exchange Program:** Proactively exchanging regulators as part of the MXGI program. The first cut regulator must be exchanged if the second cut is exchanged. Exchanging regulators through the MXGI program prevents the population from reaching the wear-out phase. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. XHP/HP and LP delivery regulator sets are opportunistically replaced if found to be 20 years or older.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Regulation, Safety, and Piping Systems: • Farm Tap Regulator Sets	Dependent on meter and regulator type: between 20-30 years old.	Farm tap sites older than 15 years were determined to have more significant condition issues. First cut regulators are installed away from premises and near the property line, making them more susceptible to corrosion and third party damage. First cut regulators were not historically replaced at the same time as second cut regulators. Due to their offset location and changes in procedures, farm tap regulator sets have historically been excluded as part of inspection and maintenance work.	Less than 0.5% of the total regulator set population is a farm tap. These regulator sets present a higher consequence due to the high pressures managed by the two pressure cuts. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for farm tap regulator sets is to reactively maintain units on an as-needed basis to address customer leaks and/or emergency calls. A 1-in-10 year maintenance inspection program for farm taps is currently in place.	EGD's proactive replacement/renewal strategy for replacing farm tap regulator sets is through: **Inspection and Remediation Program:** Continuation of comprehensive farm tap inspection program and remediating identified issues where required. **Regulator Exchange Program:** Proactively exchange regulators as part of the MXGI program. The first cut regulator must be exchanged if the second cut is exchanged. Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense for over-pressure to the customer. Outside of MXGI work, regulators are replaced if found to be 20 years or older.
Underground/Below-ground/Internal Piping Systems: • Service Extensions	N/A	A sample survey of service extensions shows that most subsets have a population with less than 50% cathodically protected. Further data collection is in progress to improve EGD's understanding of service extension condition.	Service extensions operate at lower pressures and enter the building below grade. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk* : Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts	The maintenance strategy for service extensions is to continue its inclusion in the Leak Survey Program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's replacement/renewal strategy for replacing service extensions is through: **Opportunistic Replacement:** Replace service extensions when the gas service is replaced. **Continuation of Data Collection**: Sampling will be used to reassess risks and validate the feasibility of an above-ground inspection tool.
Underground/Below-ground/Internal Piping Systems: • Multi-Family Building Services	N/A	A records search performed in the system to identify leaks associated with headers and header stations shows ~250-related calls between 2007 and 2015. An Integrity Survey will be initiated to validate population, collect data, and assess condition. Data collection is proposed to understand asset condition further.	Multi-family building services are comprised of buried piping systems from outdoor regulators to indoor meters located inside high-occupancy buildings. Not maintaining these assets can lead to: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts EGD will obtain further information on multi-family building services to better understand and manage asset risk.	The maintenance strategy for multi-family building services is to continue its inclusion in the Leak Survey Program. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's replacement/renewal strategy for multi-family building services is through: **Replacement/Renewal:** Remediate high-priority condition issues identified through Integrity Surveys.
Underground/ Below-ground/ Internal Piping Systems: • Bulk Meter Headers	N/A	EGD inspected bulk meter header sites to understand condition and site factors. Common issues identified: • No clear demarcation point between EGD and customer assets • Obsolete regulators 20 years and older • Non-adherence to current installation and maintenance specifications • Vent clearances and configurations not met, not all fittings located above-ground, and obsolete components	Not maintaining bulk meter headers can lead to the following risks: *Safety Risk:* Loss of containment *Financial Risk*: Repair, commodity loss, relights, potential property damage costs *CSAT Risk:* Reputational impacts Failure of these assets primarily exposes EGD to financial risk.	The maintenance strategy for bulk meter headers is to continue its inclusion in the Leak Survey and Corrosion Survey Programs. Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's replacement/renewal strategy for bulk meter headers is through: **Delineation Definition**: Identification of a definitive delineation point between EGD and customer assets and communicating it to the customer. All company-owned plant to be included in existing maintenance, replacement, and renewal programs. **Inspection and remediation program**. Continuation of the targeted inspection and remediation program (commenced in 2017) focusing on multi-residential premises with bulk meters. Outside of MXGI work, regulators are replaced if found to be 20 years or older.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Customer Owned Systems: • Customer-owned Piping and Appliances	N/A	EGD inspects customer-owned assets at the time of initial installation and after conducting relights. 3% of customers are issued A-tags per year (identifying unacceptable conditions that present an immediate hazard).	Improperly identifying customer-owned assets for maintenance can lead to the following risks: *Safety Risk:* Loss of containment *Financial Risk:* Emergency response *CSAT Risk:* Reputational impacts	The maintenance strategy for customer-owned assets is to continue the issuance of tags that drive the customer to address compliance issues (through the Appliance inspection Program). Reactive maintenance is on an as-needed basis to address customer leaks and/or emergency calls.	EGD's strategy for customer-owned systems includes: • Plan-Do-Check-Act process on data/programs to drive policy changes, communication updates, and targeted inspection programs. • Collection of data to refine risk assessment. • Timely communication to customers about the need to repair/replace assets, as applicable.

5.5.4 Measurement Systems

Meters represent the largest group of assets within Customer Assets. Meters measure the gas flow to the customer premises. The way gas is measured differs depending on the type of meter:

200 and 400 Series Meters have a capacity 17.0 m^3/h or less. All meters in this subclass are diaphragm meters.

>400 series Meters have a capacity 17.0 m^3/h or greater and can be comprised of the following meter types:

- Diaphragm meters
- Rotary meters
- Ultrasonic meters
- Turbine meters

Certain meters have instruments that perform compensation to accurately measure gas flow. Instruments are components of 800 series rotary meters and 800 series ultrasonic meters, used for environmental temperature and/or pressure compensation.

Meters are managed through a well-established program detailing the performance testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate identifying the meter as compliant with *Electricity and Gas Specification S-EG-02*. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada, which specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria to be accredited by Measurement Canada as an Authorized Service Provider and to adhere to *Measurement Canada Accreditation Standard S-A-01*.

5.5.4.1 Condition Methodology

The replacement of the meter population is prescribed by Measurement Canada requirements and fulfilled by System Measurement programs. Government Inspection Meter Exchange (MXGI) volumes are driven by a sampling program. Based on the failure rate of sampled meter groups, groups are either given in-service extensions or are fully replaced, ensuring the health and accuracy of the asset. Groups of meters that have short seal life extensions available to them are also replaced. This approach optimizes sampling and meter group replacement costs. Sample results and corresponding extension durations are indicative of meter group health.

The methodology for determining meter replacement is developed by Measurement Canada and varies by meter type:

200 and 400 Series Meters*:* The pace and methodology of diaphragm meter replacements is set by Measurement Canada's *S-S-06 Standard Sampling Plans*. Annual sampling is carried out on meter groups due for resealing/replacements within one year. Groups with only short extensions (<3 years) available to them are planned for replacement without sampling.

>400 Series Meters: Rotary meters, turbine meters, and instruments (electronic volume correctors) do not qualify for sample inspection. The life cycle management for these meters is to renew and replace prior to seal expiry - 100% of these assets are exchanged a year before their seal expires. Rotary meters expire after 16 to 20 years, ultrasonic meters at 10 years, turbine meters at six years, and instruments at 7 to 12 years.

Exchanged meters are processed at the meter shop on EGD premises, and its onsite facility is accredited by Measurement Canada. Processing includes labelling, cleaning, and (for most meters) performance testing. To keep up with the meter exchange program, machinery at the meter shop must also be maintained and replaced before failure.

In addition to the MXGI program, meters are also exchanged when they malfunction, when customer load changes, or if involved in billing investigations.

5.5.4.2 Condition Findings

The MXGI program is designed to keep the in-service meter population healthy. The length of extensions is dependent on sample group performance. In addition, the maximum achievable extension decreases as sampling of a group increases. For 200 and 400 series meters, the typical in-service life for meter groups is 18-24 years. As manufacturing and handling processes have evolved over time, meter groups frequently reach 24 years and beyond. The historical quantity of program-exchanged meters and non-program exchanged meters is shown in **Table 5.5-4**.

Table 5.5-4: Meter Replacements (Historical)

YEAR	MXGI PROGRAM METER EXCHANGES	NON-PROGRAM METER EXCHANGES
2014	81,897	16,332
2015	83,905	16,961
2016	63,425	17,222
2017	26,965	15,729
2018	46,651	17,796

Non-program meter exchanges are attributed to top three reasons:

- **Damaged Meter**: due to external factors and third party damage
- **Building Demolished**: Meter no longer needed
- **Size**: Meter upgrade or downgrade due to change in customer load

Meters exchanged due to leaks are low, as shown in **Figure 5.5-4**.

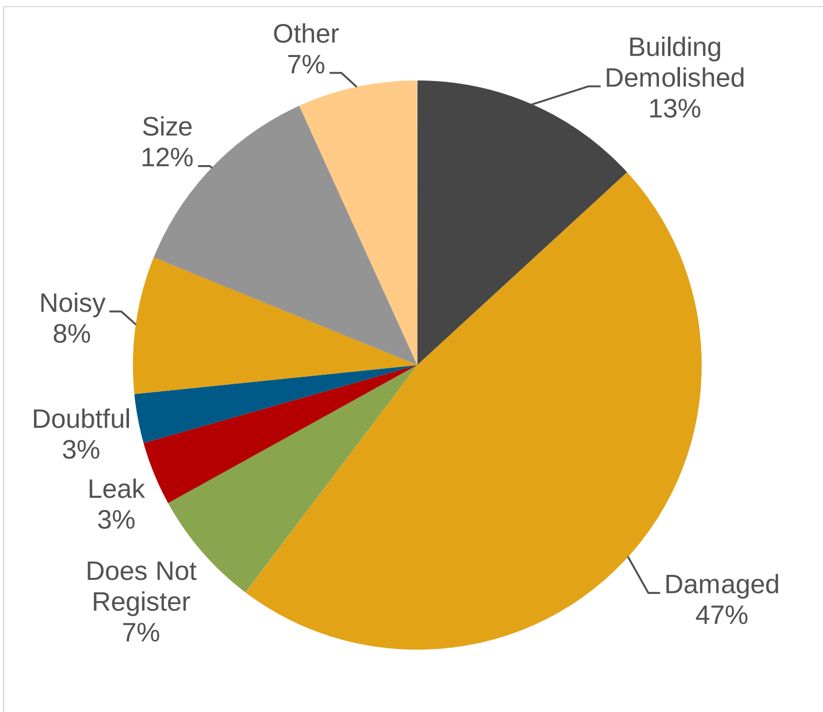


Figure 5.5-4: Causes of Non-Program Meter Exchanges (2017)

5.5.4.3 Risk and Opportunity

MXGI Risk

Failing to remove failed meters from service carries penalties under the *Electricity and Gas Inspection Act*. Penalties could eventually lead to EGD's loss of accreditation, leading to higher meter replacement program costs. The top risk for meter assets is the potential loss of accreditation through Measurement Canada to reseal meters, since this allows EGD to extend the life of meter assets that would otherwise need replacement. The financial risk would be a monetary penalty to EGD for not removing failed and overdue meters if the MXGI program was not executed, as well as the financial impacts of a reduced asset life cycle. EGD also incorporates the financial opportunity of proactively removing groups of meters that have been sampled multiple times. There is a cost benefit of removing these groups, as the cost of sampling and testing exceeds the benefits of a maximum two-year seal extension.

Non-MXGI Program Meter Exchange Risk

Non-MXGI program meter exchanges target leaking meters, damaged meters, and meters that do not flow gas. Hazards associated with leaks could result in migration and gas accumulation. However, the health and safety risk associated with meters is minimal, as the majority of meters are located outside. Historically, leaks are pinhole in size and overall leak frequency is low. Very few meters are returned due to leaks (approximately 0.007% of the population annually).

Meter exchanges for non-program work were evaluated including their regulation, safety, and piping systems, as total health and safety risk must be calculated per location. The risk analyses of non-program measurement systems are included in **Section 5.5.5**. The financial risk of meters leaking may lead to financial loss due to repair costs, relighting customer gas appliances, and any property damages.

Customer satisfaction risk may involve billing disputes due to faulty meter readings and malfunction due to meter damage, which could result in reputational damage. Low meter gas flow leads to low flow to the appliance. If appliance safeguards fail, and the appliance venting and heat exchanger are leaking, there could be a potential carbon monoxide release inside the premises, indicating a safety risk. If the appliance safeguards do not fail, EGD is potentially exposed to financial risk, involving meter replacement and appliance relight.

5.5.4.4 Strategy

The replacement program for these assets is mandated by Measurement Canada. The program maximizes the life cycle of these meters by sampling and testing to ensure the required level of metering accuracy is demonstrated. The effectiveness of this program is a result of complete asset data, appropriate systems to manage data, and statistically sound testing methodologies representative of larger population groups. This program is a model that EGD aims to use in managing other Customer Asset life cycles. EGD currently forecasts future budgets based on the historical results. The projections for 2019-2028 are shown in **Table 5.5-5**.

Table 5.5-5: Meter Replacements (Projected)

YEAR	MXGI METER EXCHANGES	NON-PROGRAM METER EXCHANGES
2019	61,895	16,561
2020	61,895	16,561
2021	61,895	16,561
2022	61,895	16,561
2023	61,895	16,561
2024	61,895	16,561
2025	61,895	16,561
2026	61,895	16,561

YEAR	MXGI METER EXCHANGES	NON-PROGRAM METER EXCHANGES
2027	61,895	16,561
2028	61,895	16,561

MXGI quantities are influenced by historical customer addition patterns and group performance of sampled meters. Previous year sampling results inform a given year's budget. An average of the meter exchanges over the past 10 years were used to project the averages for the next 10 years. To further refine longer term forecasting of MXGI quantities, a predictive failure model is being built based on historical extension and failure results of meter groups.

5.5.5 Regulation, Safety Devices, and Piping Systems

EGD is accountable for managing 2.1 million regulator sets delivering low pressure to customers. These critical assets act as the last line of defense of over-pressure to customers. A regulator set is comprised of the following components: a regulator that reduces distribution gas pressure to delivery pressure, piping, and over-pressure protection devices. The proper performance of these assets is vital for the health and safety of customers, the public, and employees.

The Regulation, Safety Devices, and Piping Systems subclass is divided into four subsets (**Table 5.5-6**):

Table 5.5-6: Regulator Set Descriptions

REGULATOR SETS	DESCRIPTION
200 and 400 Series Regulator Sets	Provides Low Pressure (LP) delivery (typically 7" wc) to primarily residential customers. They are associated to meters with capacities of 17.0 m^3/h or less.
>400 Series Regulator Sets	Provides 7" to 10" wc to high-volume regulator sets. They are associated to meters with capacities greater than 17.0 m^3/h.
XHP/HP to LP Delivery Regulator Sets	Have first and second cut regulators located together at the premises. These regulator sets are found on services off of XHP and HP mains. The first cut regulator cuts pressure from XHP/HP to IP, and the service cut regulator cuts pressure from IP to LP.
Farm Tap Regulator Sets	Used for services off of XHP and HP mains. They typically feed residential or small commercial customers in rural areas. They contain a first cut regulator remotely located from the service regulator, which cuts gas pressure down to a pressure typical of a residential area (IP). The first cut regulator is close to the property line with a buried service installed, leading to the service regulator at the premise.

5.5.5.1 200 and 400 Series Regulator Sets

200 and 400 series regulator sets account for approximately 96% of all regulator sets. Currently, regulators with single meters are replaced at the same time as meters exchanged through the MXGI program. Based on MXGI schedule requirements, replacements can happen as soon as after 10 years of service. Despite limited regulator data available, EGD has begun to collect regulator data as part of program work. A surveyed sample set of 6,785 regulator sets confirm that most have the same age as the meter. Based on these results, meter age is used as a proxy for regulator age.

Using the meter age as a proxy for the age of the regulator, **Figure 5.5-5** shows that 0.002% of 200 and 400 series regulator sets are older than 40 years and 16% are older than 20 years:

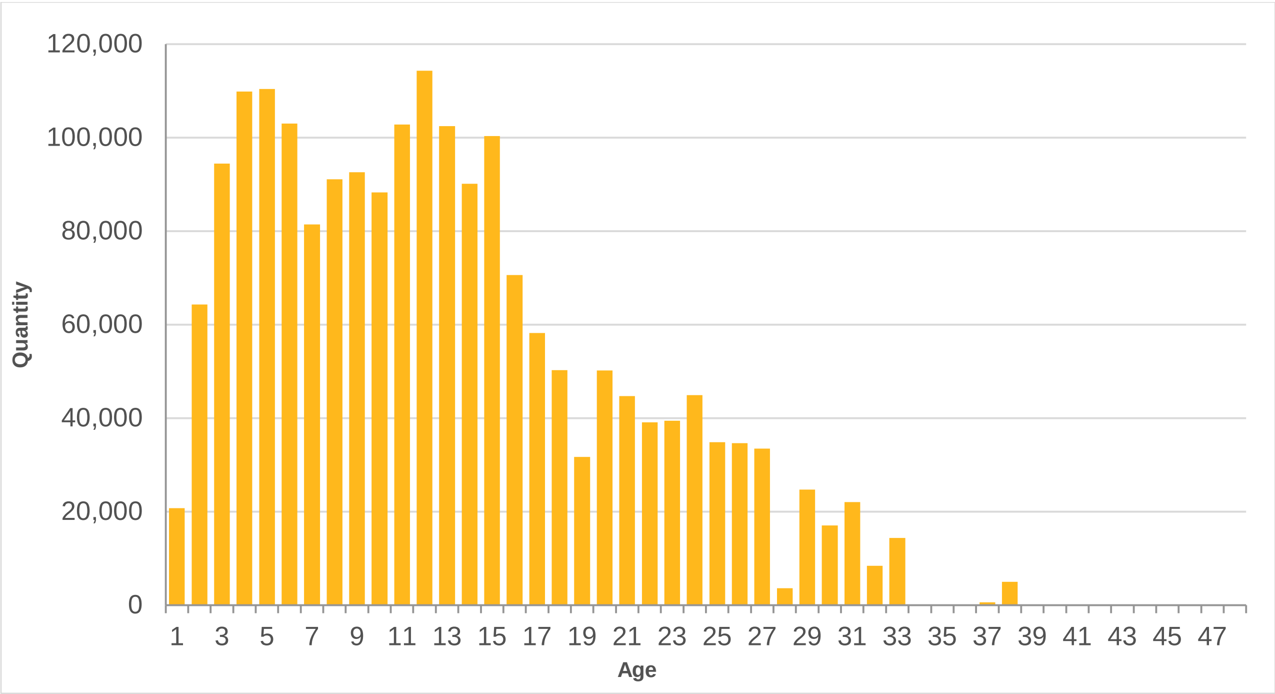


Figure 5.5-5: Age Distribution of Meter Sets

5.5.5.1.1 CONDITION METHODOLOGY

Regulator set condition is determined by performance, corrosion of piping and regulators, and adherence to installation specifications. Specific factors related to the condition of regulation sets were identified:

- Regulator performance is influenced by the age of the asset (mechanical wear and tear) and its physical environment, potentially affecting its ability to lock up in abnormal conditions (to prevent over-pressure), and its ability to contain gas (absence of leaks). The assessment is determined through failure data, laboratory testing, and age of the asset.
- Corrosion of piping and regulators can lead to loss of containment and faulty regulator performance. This is determined through an on-site visual assessment.
- Adherence to installation specifications is affected by a number of external factors which can affect failure rates and consequences. These include physical changes in site condition made by the customer after the initial installation of the set, such as new building openings/vents, increased grade and unreported damage, as well as regulatory specifications and codes that have changed since installation. This is determined by an on-site visual assessment.

Issues and outcomes affecting regulator sets, safety devices, and piping systems are summarized in **Table 5.5-7**:

Table 5.5-7: Component Issues & Outcomes Summary

COMPONENT	ISSUE	OUTCOME
Regulator	Incorrect delivery pressure	Undesirable downstream effects causing an emergency response and potentially higher severity consequences.
External reliefs	External relief missing on downstream regulator	Absence of this component removes a required line of defense to over-pressure protection and can lead to an over-pressure event.
Regulator cap	Damaged or missing	A damaged or missing regulator cap can allow water or debris to enter the regulator housing, resulting in faulty performance and compromised pressure control.
Vent	Orientation not downwards	The vent must point downwards to reduce the probability of water or debris entering regulator control components.
	Missing or incorrectly sized vent screen	Missing or incorrectly sized regulator vent screens can allow insects and/or debris to block vent openings, impeding regulator diaphragm movement and compromising pressure control.
	Presence of vent shields	Vent shields are legacy components that cover vents. Debris or ice can build up on the vent shield, causing vent blockage and affecting regulator performance.
	Vent too close to grade	Vents that are too close to grade can cause splashing and freeze-up of the opening, or can be covered with snow/ice, compromising pressure control.
	Insufficient vent clearance to building openings	Vents must comply with minimum distances to building openings to prevent gas migration.
Regulator	Regulator touching customer supply lines	Regulators touching customer supply lines can cause electrical continuity of below-ground and above-ground systems. This can promote migration of corrosion between below- and above-ground piping.
	Regulator too close to ground	Regulators that touch the ground are more susceptible to corrosion.
Fittings	Buried fittings	Fittings, typically winglocks, must be above-ground for accessibility to shut off gas in emergencies and to avoid corrosion.
Regulator, Piping, Fitting, External Reliefs	Corrosion	Severe corrosion and pitting can lead to a loss of containment or abnormal operating condition.
All	Damaged by third party or environmental factors	Damages can lead to a loss of containment or abnormal operating condition.

These are some of the factors can contribute to failure of the regulation system and can cause pressured gas to enter the customer's supply piping, resulting in the failure of gas equipment, loss of containment, gas accumulation, and potential incidents.

5.5.5.1.2 CONDITION FINDINGS

Three main condition categories were evaluated for 200 and 400 series regulator sets:

Regulator Performance: Regulator performance is affected by wear-out due to a combination of internal mechanical cycling and field operating conditions such as the presence of debris in the gas or atmosphere, ice or snow load, and regulator set location. There are additional layers of protection that are part of the EGD's installation standard that can mitigate regulator failure incidents. EGD uses actual regulator failure and exchange data where possible to establish failure modes and frequencies.

Data extraction and analysis has shown that 28,000 regulators have been exchanged independent of meter exchanges, between 2005 and 2014. This historical data did not indicate the reasons for regulator exchanges - a conservative approach for the reliability study assumed that all of the exchanges were due to failures. Failures may be due to a relieving regulator, regulator creeping, under-pressure, over-pressure, or gas escapes. Non-failure replacements may be due to handling issues, customer load changes, changes to building openings, obsolete regulators, corrosion, and damages. As shown in **Figure 5.5-6,** there have been approximately 2,800 regulator exchanges independent of meter exchanges per year, equivalent to 0.14% of the total population of 2.0 million.

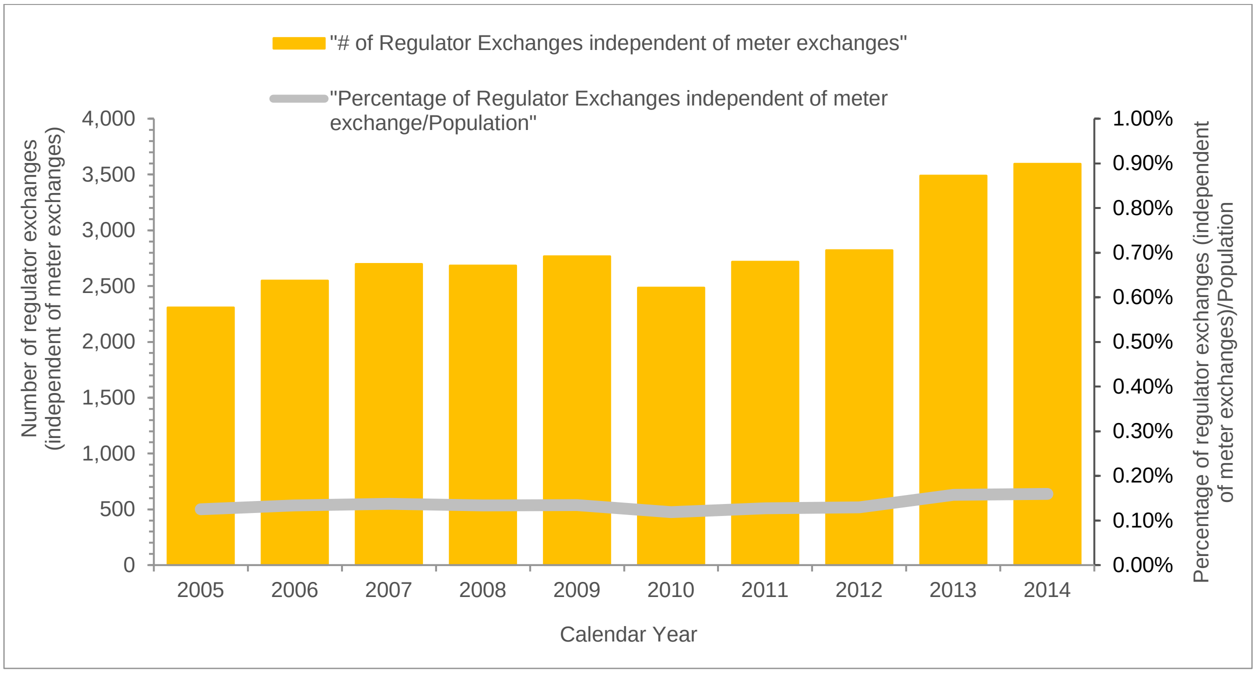


Figure 5.5-6: Non-MXGI Regulator Exchanges by Calendar Year

Figure 5.5-6 indicates that the quantity of regulator exchanges independent of meter exchanges is relatively low. Further analysis will be done to distinguish failure and non-failure exchanges within this data set. Going forward, failure classifications in the system by field personnel will improve the identification of the root causes of regulator replacements.

Corrosion: A survey to investigate regulator corrosion on regulator sets was carried out across a population of 20,700. Corrosion distribution by age is shown in **Figure 5.5-7**.

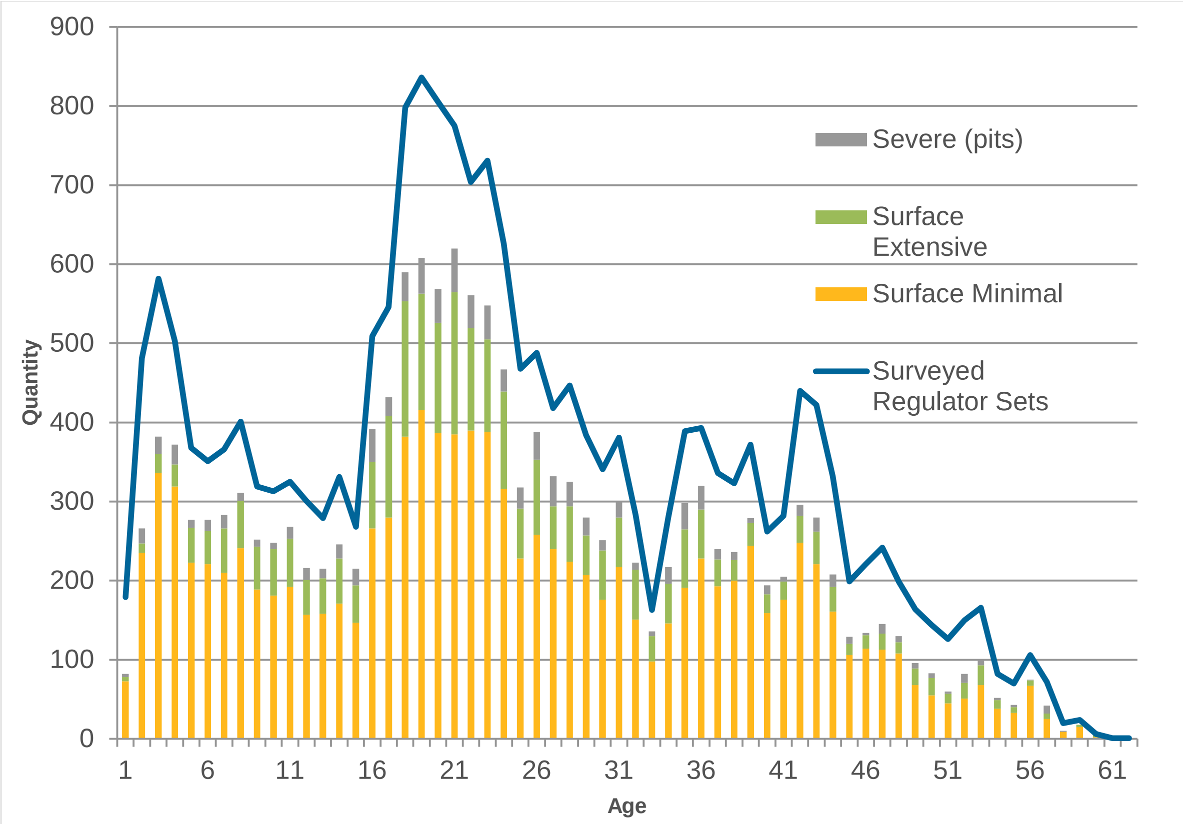


Figure 5.5-7: Regulator Sets - Corrosion Distribution by Age

Results show that 73% of the surveyed regulator sets have varying degrees of corrosion. Each vintage has at least 50% of the population of regulator sets with signs of corrosion. However, **Figure 5.5-7** shows that the majority of regulator sets have minimal surface corrosion and only 5% was categorized as severe.

Adherence to Installation Specifications: In addition, it has been observed that regulator sets can have deviations from current installation specifications. This can occur when site conditions change over time, such as: buildup of grade level, addition of new vents/building openings, and building structures, as well as broken/missing components. In addition, installation specifications have changed over time and legacy specifications and components may still exist in some of these sets. These issues are rectified as part of MXGI program work.

5.5.5.1.3 RISK AND OPPORTUNITY

The majority of customers are connected to the distribution system through 200 and 400 series regulator sets. Poor condition of these assets can result in a loss of containment due to the regulator not reducing gas pressure to the premises within designed limits. This could result in a loss of containment within the building, potentially allowing gas migration. Delivery pressures outside of normal operating conditions (under- or over-pressure) can also negatively affect appliance performance. If appliance safeguards fail, building occupants may be potentially exposed to carbon monoxide.

Failure of these assets exposes EGD to financial risk – a loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances, property damage, and personal injury due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may result in reputational impact to EGD.

The safety risk is evaluated to be broadly tolerable (low) partially due to EGD Engineering policies surrounding these assets. Regulator exchanges through the MXGI program and the policy to remove regulators older than 20 years help ensure the safety risk remains broadly tolerable in the future.

5.5.5.1.4 STRATEGY

200 and 400 series regulator sets serve the majority of customers and are critical assets for the safe and reliable delivery of natural gas. The strategy is to continue exchanging regulators and correct other compliance issues as part of the MXGI program.

Run-to-failure is not an acceptable policy for this asset, as regulators are the last line of defense to protect customers from over-pressure events. Exchanging the regulators as part of the MXGI program mitigates the population from reaching the wear-out phase and ensures optimum regulator performance and safety.

As part of the continuous improvement process on asset life cycle strategies, additional data will be collected and analyzed to understand asset health and condition, so that the strategies can be fine-tuned to more efficiently manage the associated risks in the future.

By exchanging the regulator proactively as part of the MXGI program, the health and safety risk is managed and remains broadly tolerable because compliance issues are resolved before regulator failure. Financial and customer satisfaction risk is managed by replacing regulators during MXGI program exchanges. By proactively replacing regulators nearing end-of-life, the financial impact of responding to emergency calls is minimized. A proactive strategy ensures that failures are minimized, reducing customer outages and maintaining a reputable standing as a gas provider.

This strategy manages risk to the lowest practicable level. In addition, it applies a planned and controlled spend of capital dollars, while maintaining the current level of operational reliability. A Plan-Do-Check-Act strategy is used to promote continuous improvement of the life cycle strategy. The continuous collection of failure data will help support improvements.

5.5.5.2 >400 Series Regulator Sets

>400 series regulator sets account for approximately 2% of all regulator sets. These are primarily used by commercial, industrial, and high density residential customers. Failure of the regulator has the potential to cause over-pressure to the customer's supply line and appliances. Over-pressure can result in a loss of containment within the building, potentially allowing gas migration. Currently, these commercial regulators are exchanged if found to be 20 years or older. As shown in **Figure 5.5-8**, 20% of the population are 40 years and older, and 58% are 20 years and older.

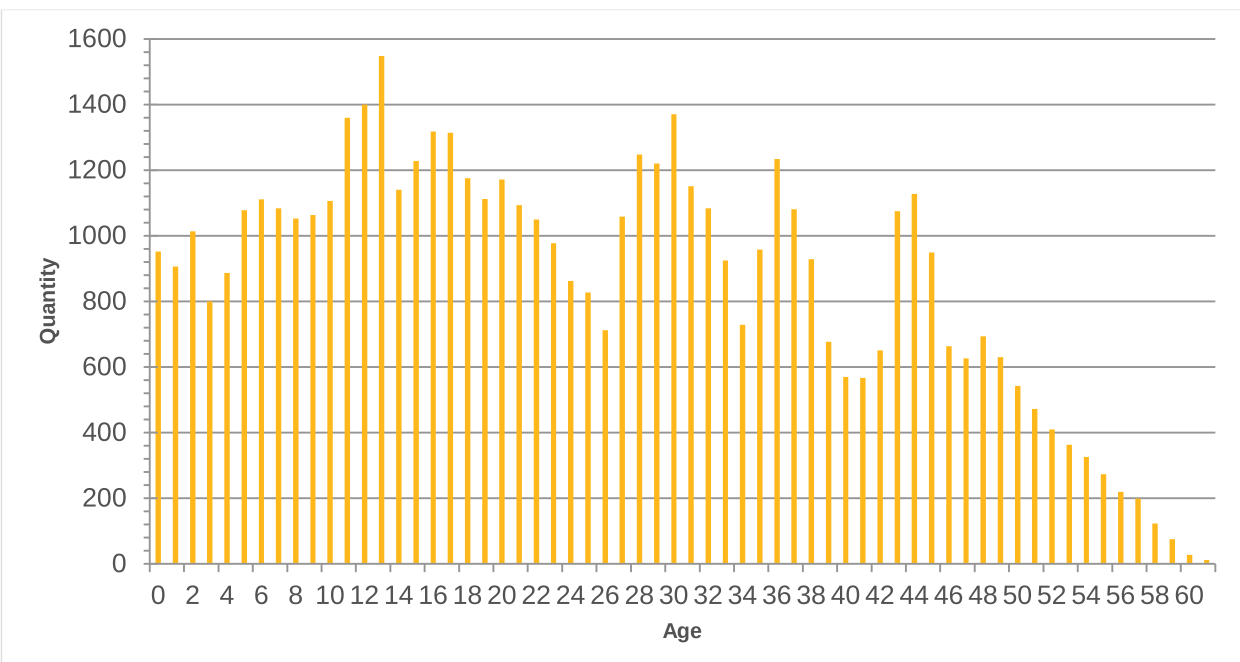


Figure 5.5-8: Age Distribution of >400 Series Regulator Sets

Commercial Meter Manifolds are a sub-set of >400 Series regulator sets. These installations of multiple banked meters are typically located in commercial plazas. Adding multiple meters for new customers can eventually compromise the safety and design of the original manifold. For example, brackets may no longer adequately support piping, meters, and regulators. Piping may make contact with other regulator set components, barriers may no longer protect the set, and venting clearances may no longer be adequate. This type of >400 Series regulator set is particularly susceptible to condition issues and non-adherence to installation specifications, as EGD has not historically provided specifications on the addition of new meters to existing manifolds and criteria required for regulator set rebuilds.

5.5.5.2.1 CONDITION METHODOLOGY

Refer to **Section 5.5.5.1.1**.

5.5.5.2.2 CONDITION FINDINGS

Three main condition categories were evaluated for >400 series regulator sets:

Regulator performance*:* **Figure 5.5-8** shows that more than half of these regulators are older than 20 years. Without failure data for these assets, EGD has used station regulator failure data as a proxy to determine the probability of failure due to external leaks and ability to lock up. While a regulator used in a station may be the same as a Farm Tap or >400 series regulator, there are two main differences in the handling and assessment of station regulators:

- Stations have periodic inspections, likely resulting in more frequent reporting of failures as a result of proactive maintenance. >400 series regulators do not currently have an inspection program.
- Station regulators are exchanged more frequently due to lock-up testing results from these inspections. >400 series regulators have historically been left in service for over 20 years.

Using SMA input, a multiplier was developed and applied to the probability of failure to adjust for these differences.

Corrosion*:* A preliminary visual Integrity Survey on a sample population identified issues related to corrosion and adherence to installation specifications. Sixteen percent of sites had severe corrosion or non-adherence to installation specifications. 37% of regulator sets had corrosion of some extent. **Figure 5.5-9** shows that light corrosion was most frequently found on these regulator sets across all ages. Heavy corrosion was only found on regulator sets 29 years and older, showing a variation in corrosion across the age population.

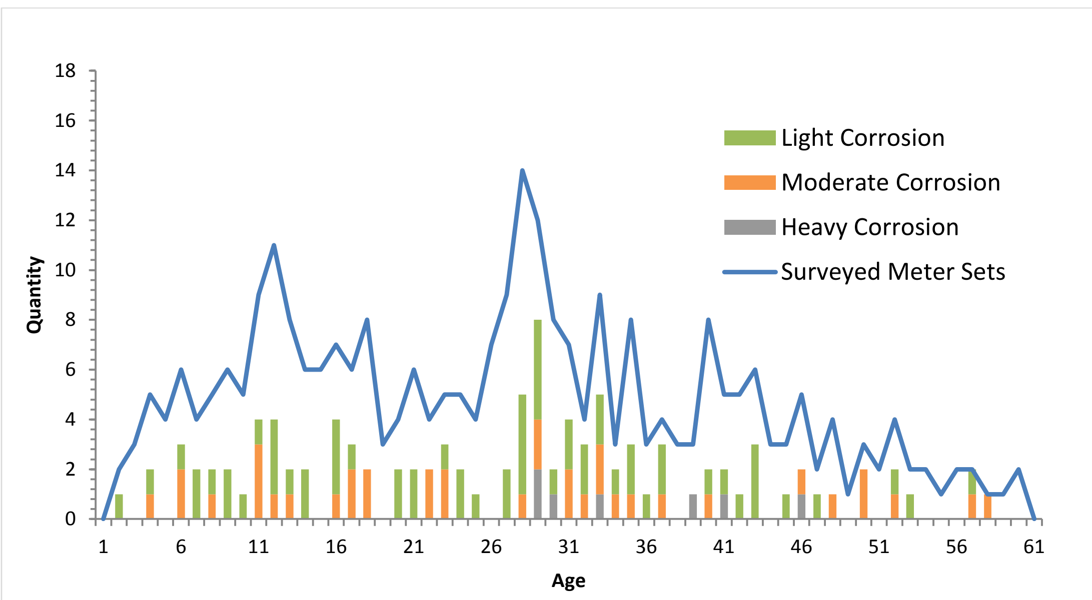


Figure 5.5-9: Corrosion Distribution of >400 Series Sets

Adherence to Installation Specifications*:* The sample survey also identified sites not adhering to current installation specifications. Results show that non-adherence to installation specifications is not specific to a certain age of >400 Series Regulator. The most prevalent issues found include:

- Issues with vent clearances and other components
- Regulator touching pipe
- Vent not pointing downward
- Missing vent screen
- Improper valve distance from ground

5.5.5.2.3 RISK AND OPPORTUNITY

Based on historical failure data, the probability of failure is low. In addition, >400 series regulator sets account for just 2% of all regulator sets and are predominantly used in commercial, industrial, or higher density residential premises. Commercial and industrial premises typically have higher populations at risk than single-family residential premises, as well as higher delivery flow rates. This results in potentially more severe consequences for safety, financial, and customer satisfaction when compared to smaller flow regulator sets.

EGD may be exposed to a safety risk due a loss of containment if the regulator cannot control the gas pressure to the premises, leading to an over-pressure event that may damage downstream equipment and property and migrate gas into the customers' premises, resulting in gas accumulation and a potential incident.

Failure of these assets exposes EGD to financial risk – a loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances, property damage, and personal injury due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may result in negative reputational impacts to EGD.

The main driver of risk for these assets is financial, followed by customer satisfaction and safety, due to the likely outcome of a failure only requiring remediation. Compliance with existing EGD policies keeps the safety risk for these assets broadly tolerable (low) into the future.

5.5.5.2.4 STRATEGY

>400 Series regulator sets typically serve higher-usage and higher-density customers. The safety and reliability impacts of an incident could be high. The strategy is to inspect the total population and remediate issues within 10 years. By proactively inspecting and remediating issues on a priority basis, the risk of an in-service failure will be reduced. If these regulator sets are allowed to run to failure, there will be inconvenience to the customer, a financial impact due to emergency call responses, and the possibility of a health and safety incident.

This strategy manages safety risk by remediating all discovered compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees, and the public. Remediation may entail a full replacement of the regulator, meter, and riser, and adjustments to bring the regulator set to current installation specifications. The planned and controlled spend of capital dollars minimizes the financial impact of responding to emergency calls. The strategy improves on the current level of operational reliability by ensuring that failures are prevented, minimizing customer outages and maintaining a reputable standing as a gas provider.

The first four years (starting from 2017) will be used to inspect and remediate targeted populations that are more likely to have non-adherence to installation specifications and corrosion. An annual inspection program will continue for the remainder of the population. Remediation work resulting from these inspections will continue to reduce risk to the lowest practicable level. Additionally, some >400 series regulator sets are inspected and maintained through the MXGI program, as current EGD policy is to replace assets 20 years and older when discovered in the field. Further analysis is underway to evaluate replacement policies and frequencies for these regulator sets. The associated services are surveyed for leaks every five years and surveyed for corrosion every year.

Similar to the assets in Measurement Systems, the continuous improvement strategy for this program is made possible through data collection. Data will be used to optimize the renewal schedule and potentially the change program pace. Data will continue to be collected on regulator sets that become part of the MXGI program. Data such as condition, adherence to installation specifications, regulator attributes, and failure classifications will be collected to iterate data models. Refinements include validating criteria that assist in prioritizing high risk locations and analyze asset life cycle and risk assessments.

5.5.5.3 XHP/HP to LP Delivery Regulator Sets

XHP/HP to LP Delivery regulator sets account for 1% of all regulator sets. These sets have two regulator cuts in series: one reducing the pressure from XHP/HP to IP, and a second cut reducing pressure from IP to LP. External relief valves are a component required on some XHP/HP regulator sets, based on the inlet pressure and the types of regulators on the set. These components provide a second line of defense against over-pressure by allowing gas exceeding its set pressure to relieve out of the set.

The entire XHP/HP regulator set population was surveyed in 2015 and 2016 to identify and remediate any immediate concerns (e.g., missing first cuts, leaks, improper relief vents, etc.) and to assess the health of the asset population. The age distribution of these regulator sets are shown in **Figure 5.5-10**.

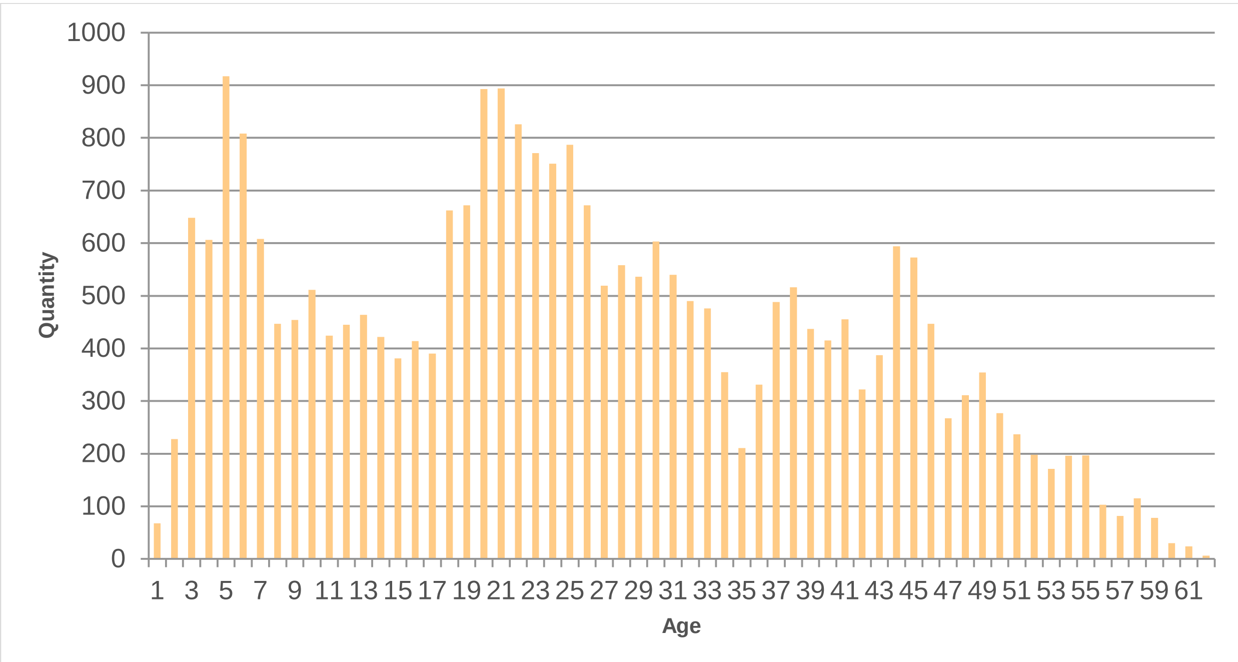


Figure 5.5-10: Age Distribution of XHP/HP to LP Delivery Regulator Sets

The age distribution of XHP/HP regulator sets shows that 22% are 40 years and older, and 65% are 20 years and older.

5.5.5.3.1 CONDITION METHODOLOGY

Refer to **Section 5.5.5.1.1**.

5.5.5.3.2 CONDITION FINDINGS

Three main condition categories were evaluated for XHP/HP to LP Delivery regulator sets:

Regulator Performance: Failure data specific to first cut XHP/HP regulators has not historically been categorized. Station regulator data was used as a proxy in determining the probability of failure due to external leaks and the ability to lock up.

Corrosion of piping and regulators: A survey was conducted to identify corrosion and issues with adherence to installation specifications. 78% of the total population was found to have some degree of corrosion. **Figure 5.5-11** shows that most sites with signs of corrosion have minimal surface corrosion. All sites with severe corrosion have been remediated.

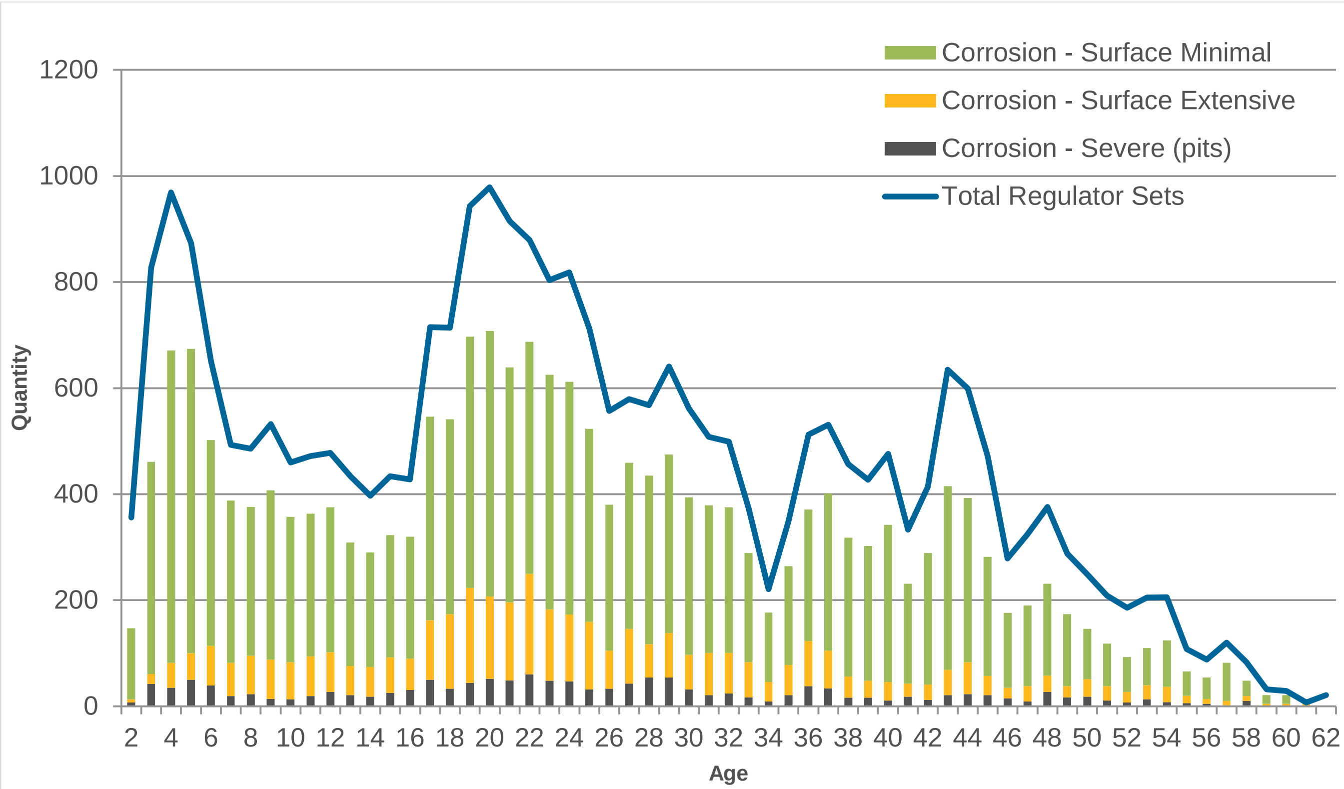


Figure 5.5-11: Corrosion of XHP/HP to LP Delivery Regulator Sets

Adherence to Installation Specifications: Non-adherence to installation specifications were found on these regulator sets, prioritized on the likelihood to lead to an incident:

- Improper vent orientation
- Damage to the regulator cap
- Missing vent screens
- Presence of vent shields
- Missing external reliefs

All of the sites with these issues have been remediated. Older regulator sets were more likely to exhibit these issues. Increased regulator set age can result in more changes to site conditions and installation policies over the lifetime of the asset.

In addition, sites found to have old/obsolete regulators were remediated. Approximately 65% of sites with identified condition issues have been remediated to date. The following condition issues are still outstanding:

- ¾" screen
- Vent height from ground
- Buried fitting
- Vent proximity compliance
- Regulator touching pipe
- Regulator within ½" of piping
- Regulator height from ground

These issues are less likely to contribute to an incident and will also be remediated.

5.5.5.3.3 RISK AND OPPORTUNITY

Regulators are the last line of defense protecting the customer from over-pressure. Over-pressure can result in a loss of containment within the building, making gas accumulation and an incident possible. The XHP/HP regulator sets present a higher consequence due to the higher pressures managed by two pressure cuts. The probability of failure is evaluated to be the same for all service regulators of any flow capacity delivering low pressure. However, the evaluated frequency of HP/XHP regulators failing is relatively low due to the small population – roughly 1% of the total regulator set population.

EGD may be exposed to a safety risk due a loss of containment if the regulator cannot control the gas pressure to the premises, leading to a gas over-pressure event that may damage downstream equipment and property and migrate into the customer's premises, resulting in gas accumulation and a potential incident.

Failure of these assets exposes EGD to financial risk – a loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances, and property damage due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may result in negative reputational impacts to EGD.

The main driver of risk for these assets is financial, followed by customer satisfaction and safety, due to the likely outcome of a failure only requiring remediation. Compliance with the existing EGD policies keeps the safety risk for these assets broadly tolerable (low) into the future.

5.5.5.3.4 STRATEGY

Immediate safety concerns were remediated as part of the 2015-2016 survey on the entire population. The strategy is to proactively remediate the remaining 35% of sites with identified compliance issues within three years. Remediation of compliance issues started in 2017 and continues until 2020. Remediation may entail a full replacement of the regulator, meter, and riser, and adjustments to bring the regulator set to current installation specifications.

Units with high-risk issues have already been remediated, reducing the likelihood of their failure in service. Two more years are required to complete the remaining remediation work. By prioritizing the remediation of high-risk issues, lower-risk issues can be addressed towards the end of the program, allowing EGD to manage risk and resources effectively. Safety risk is reduced to the lowest practicable level by remediating all discovered compliance and integrity issues before a failure occurs.

Remediation measures are site-dependent. Sites with multiple or extensive condition issues are fully replaced. Financial risk is managed through a planned and controlled spend of capital dollars. By proactively managing failures, the financial impact of responding to emergency calls is minimized. Customer satisfaction risk is managed by ensuring failures and corresponding customer outages are minimized. This strategy supports an improvement on existing operational reliability.

Beyond this remediation strategy, there is an existing policy of not running these regulators to failure. XHP/HP regulator sets with 200 and 400 series meters have regulators proactively replaced in conjunction with the MXGI program. In addition, current EGD policy requires the first cut regulator and external relief valves to also be replaced when the second cut regulator is replaced. Regulators on commercial XHP/HP regulator sets are replaced if found to be 20 years or older. The associated services are surveyed for leaks every five years and surveyed for corrosion every year.

This proactive strategy mitigates risk to the lowest practicable level by remediating all compliance and integrity issues identified on these assets. This work maintains the integrity of assets to minimize loss of containment, extend asset life, and ensure compliance with codes and standards.

Similar to the assets in Measurement Systems, the continuous improvement strategy for this program is made possible through data collection. Data will continue to be collected on regulator sets that become part of the MXGI program. Data such as condition, adherence to installation specifications, regulator attributes, and failure classifications will be collected to iterate data models. Refinements include validating criteria that assist in prioritizing high risk locations and analyze asset life cycle and risk assessments.

5.5.5.4 Farm Tap Regulator Sets

Farm taps make up less than 0.5% of all regulator sets. The majority of these assets are found in rural areas. A farm tap is the first cut regulator reducing pressure from XHP/HP to IP. Its purpose is to reduce the pressure to meet the design criteria for the downstream regulator. A malfunctioning farm tap regulator has the potential to create downstream hazards. A failure of the regulator set could potentially cause a higher than acceptable pressure entering the customer's premises. This over-pressure can result in downstream customer appliances failing, loss of containment inside the premises, gas accumulation, and a potential incident.

As most farm tap regulators are installed away from the premises and near the property line, they are exposed to more elements originating from the roadway. Their placement can also make them susceptible to third-party damage from maintenance equipment and vehicles.

The majority of farm taps are 20 years old or younger (see **Figure 5.5-12**). An inspection and remediation program in 2017 targeted the farm tap population 20 years and older, which were designed with two elbows (current farm taps have four elbows). The older design made farm taps more susceptible to condition issues associated with ground movement. The four-elbow swing was designed to address settlement issues.

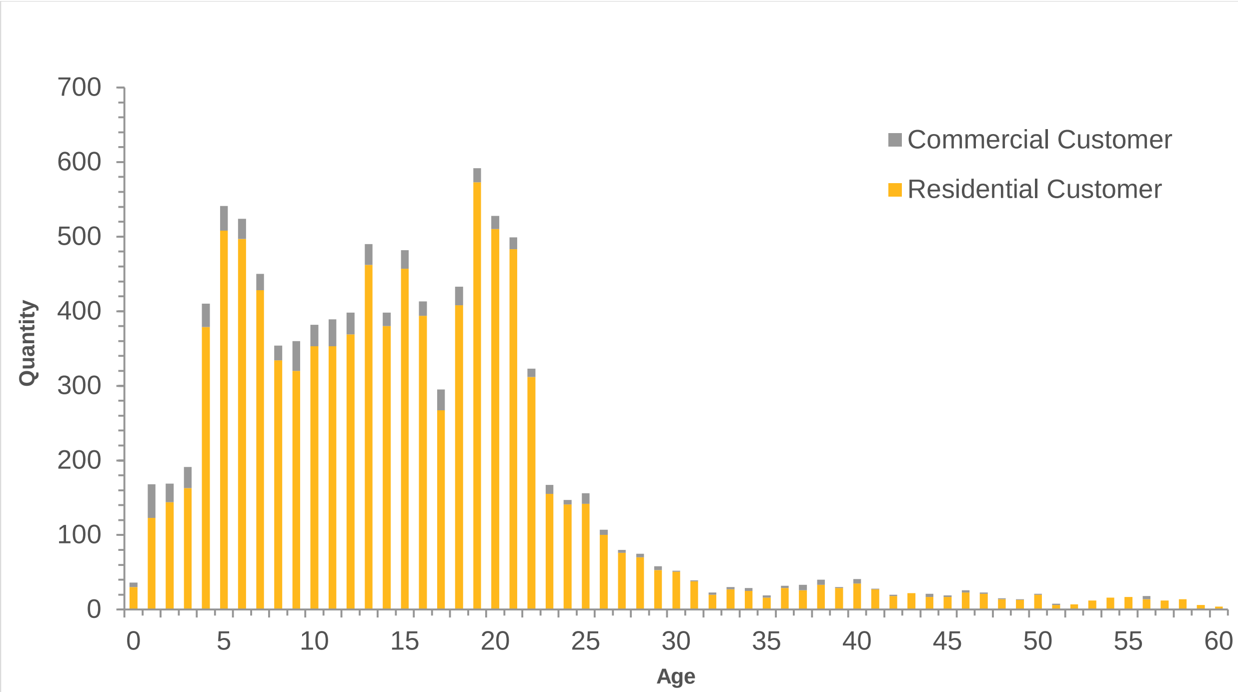


Figure 5.5-12: Farm Tap Regulator Set Age Distribution

5.5.5.4.1 CONDITION METHODOLOGY

Refer to **Section 5.5.5.1.1**.

A component-based Failure Mode and Effect Analysis (FMEA) was performed through SMA reviews to identify the critical components of the farm tap assembly, their failure modes, causes and effects, required safeguards, and potential consequences if safeguards fail. Failures were prioritized according to severity, frequency of occurrence, and ease of detection.

5.5.5.4.2 CONDITION FINDINGS

Three main condition categories were evaluated for farm tap regulator sets:

Regulator performance*:* Regulators are required to be replaced if found to be 20 years or older. The current exchange policy also includes exchanging the regulator if the second cut regulator is being exchanged as part of the MXGI program. A program currently in place is inspecting and remediating farm taps older than 20 years with a view to reducing the likelihood of age-related failures.

Failure data specific to farm tap regulators has not historically been categorized. However, in 2015 a visual Integrity Survey was conducted on a sample population of farm tap regulator sets. Remediating the issues identified in this survey was the basis for future remediation work and benefits were quantified in the risk assessment. Reliability modeling analysis will be performed on farm taps through the Asset Health Review program using station regulators data as a proxy to determine the probability of failure due to external leaks and ability to lock up. Over time, more farm tap data will be collected and used for reliability modeling.

Corrosion of piping and regulators: Data from the 2015 sample survey provides insight into the asset condition of farm taps. The extent of corrosion versus age is displayed in **Figure 5.5-13**.

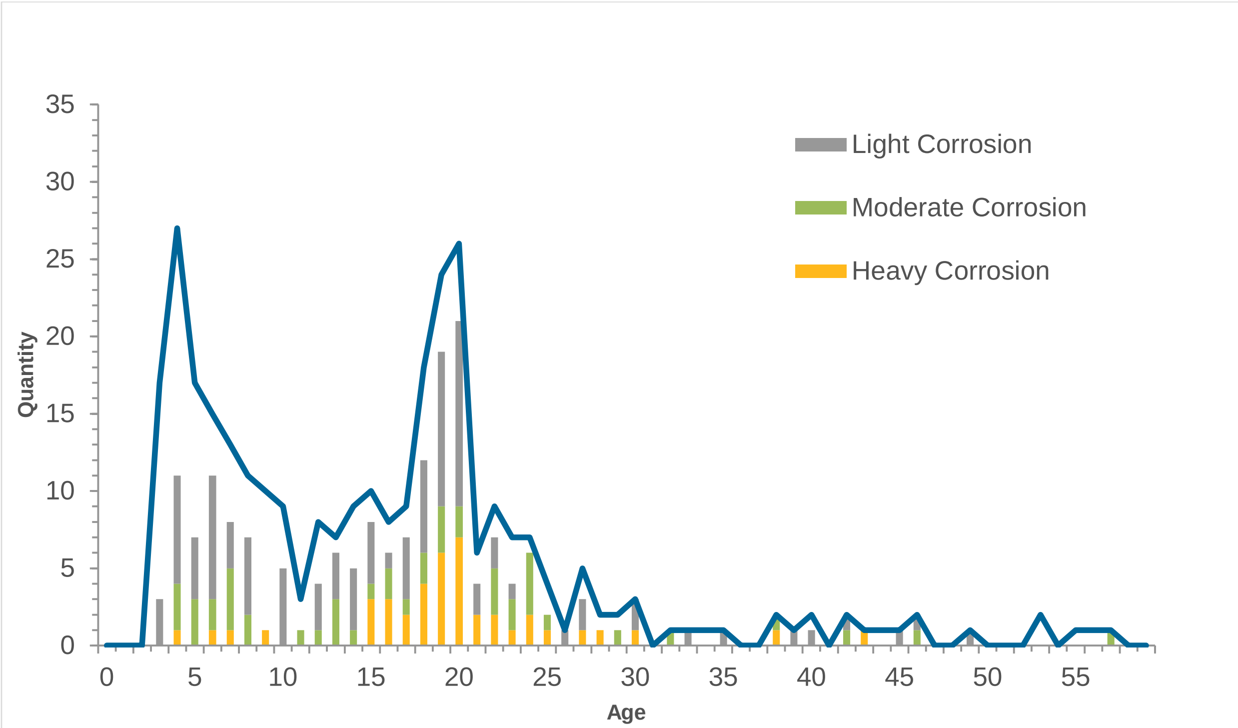


Figure 5.5-13: Corrosion of Farm Tap Regulators

Figure 5.5-13 indicates that a higher count of corrosion impact is observed on farm tap regulator sets 15 years and older. This is attributed to their typical location (in rural areas above-ground and near roadways).

Adherence to installation specifications: The sample survey indicated that some farm tap installations had issues related to adherence to installation specifications. The most frequent issues are as follows:

- Vent clearance issues
- Improper vent orientation
- Broken caps
- Missing vent screens
- Obsolete regulators

Most vintages had some level of non-adherence to installation specifications with an increasing trend as farm taps approached 20 years of age. This is due to site conditions and installation specifications changing over time.

Based on the survey, farm tap sites older than 20 years were determined to have more significant condition issues and were prioritized for remediation. A proactive strategy to inspect and remediate will prevent a potential peak in future failures. This approach also distributes future workload while reducing risk.

Based on the FMEA, the main critical components for farm taps are regulators, inlet and outlet shut-off valves, inlet and outlet risers, external relief valve, and piping and fittings. A review of the potential consequences of these component failures reveals potential health and safety risks. The FMEA identifies the lack of maintenance as one of the main causes of failures on these critical components.

5.5.5.4.3 RISK AND OPPORTUNITY

Farm tap regulator sets present higher risks due to the higher pressures managed by the dual configuration regulator set. The probability of failure is evaluated to be the same for all service regulators of any flow capacity delivering low pressure. However, the evaluated frequency of farm tap regulators failing is relatively low due to the small population – less than 0.5% of the total regulator set population.

EGD may be exposed to a safety risk due a loss of containment if the regulator cannot control the gas pressure to the premises, leading to a gas over-pressure event that may damage downstream equipment and property and migrate into the customer's premises, resulting in gas accumulation and a potential incident.

Failure of these assets exposes EGD to financial risk – a loss of containment triggers emergency calls which may result in repair costs, commodity loss, relighting customers' gas appliances, and property damage due to a gas leak. Regulator failure and customer service disruptions resulting from these failures may result in negative reputational impacts to EGD.

The main driver of risk for these assets is financial, followed by customer satisfaction and safety, due to the likely outcome of a failure only requiring remediation. Compliance with the existing EGD policies keeps the safety risk for these assets broadly tolerable (low) into the future.

5.5.5.4.4 STRATEGY

Due to their offset location and changes in procedures over time, farm tap regulator sets have largely been excluded as part of inspection and maintenance work. The strategy is to inspect the total population and remediate issues within 10 years. Remediation may entail a full replacement of the regulator, meter, and riser, and adjustments to bring the regulator set to current installation specifications.

The FMEA results on farm taps showed that a routine inspection and maintenance program over the lifetime of the asset would reduce in-service failures through the proactive identification of assets that have failed or are nearing end-of-life. Program activities will be scheduled to ensure that all farm taps are inspected once every 10 years. The first three years (starting from 2017) will be used to inspect and remediate target populations more likely to have installation specification and corrosion issues. The remaining seven years will be used to pace out remaining inspection and remediation work, allowing EGD to effectively manage risk. Additionally, farm taps associated to 200 and 400 series meters are exchanged through the MXGI program. Current EGD policy requires the first cut regulator and external relief valves to also be replaced when the second cut regulator is replaced. Associated services are surveyed for leaks every five years and surveyed for corrosion every year.

This strategy manages safety risk by remediating all discovered compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees, and the public. The planned spend of capital dollars minimizes the financial impact of responding to emergency calls.

From a customer satisfaction risk perspective, this proactive strategy ensures that the risk of failure is mitigated, minimizing customer outages and maintaining a reputable standing as a gas provider.

5.5.6 Below-ground and Internal Piping Systems

Below-ground and inside piping systems refers to piping running below grade, and/or piping running inside a building, typically located upstream of inside meters. The below-ground and internal piping systems subclass is categorized into:

Service Extensions: Refers to service piping installed between the regulator (outside of the building) and the meter (inside the building) where the pipe enters the building below ground.

Multi-Family Building services: gas distribution networks within multi-unit buildings. Each may consist of a garage header, vertical headers, off-garage service pipes, and/or vertical headers supplying meters for individual units. There are two main metering configurations:

- **Ensuite Metering**: internal piping leading to meters inside individual units.
- **Banked Metering**: internal piping leading to meters grouped together in the garage or basement on each individual level of the building.

Bulk Meter Headers: gas distribution networks consisting of underground piping downstream of a meter feeding multiple individual customer buildings. Regulation occurs downstream of the meter. These networks are installed by EGD.

5.5.6.1 Service Extensions

Service extensions refer to EGD-owned steel piping from the regulator (outside the building) to the meter (inside the building). Its entry through the building wall is below grade. Service extensions are commonly found at urban wall-to-wall premises. Due to lack of space at the frontage of these locations, the riser, regulator, and service extension are outside the building, and the meter is located inside the basement. EGD currently has 14,240 service extensions that are found on 0.7% of services in the network.

Figure 5.5-14 shows the age distribution for service extensions. The majority of the population is younger than 25 years. Some factors contributing to installations within this timeframe include the renewal of cast iron systems in downtown Toronto, and a program moving regulators from inside to outside customer premises.

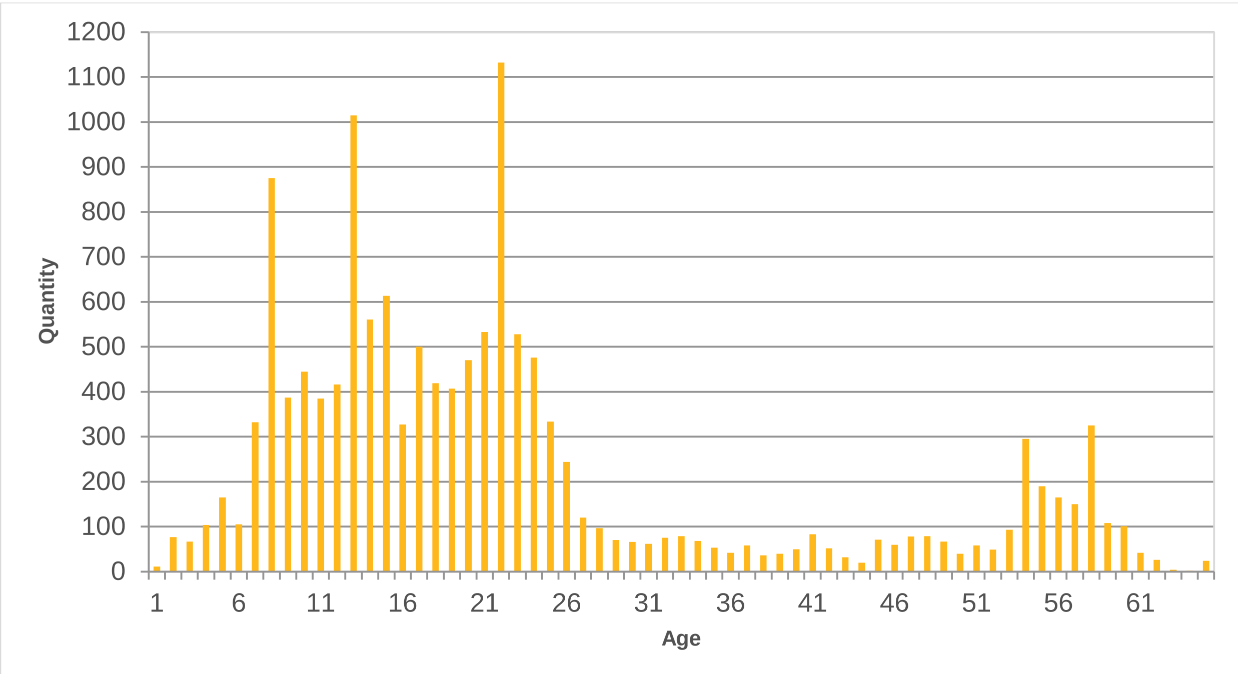


Figure 5.5-14: Age Distribution of Service Extensions

5.5.6.1.1 CONDITION METHODOLOGY

All service extensions are isolated from cathodically protected steel services. Service extensions with depleted anodes are unprotected and more susceptible to corrosion, ultimately resulting in a loss of containment. Cathodic protection and coating types are two parameters influencing corrosion rate. The application of cathodic protection on service extensions was estimated by conducting pipe-to-soil inspections on a statistically representative sample. In addition, samples of unprotected service extensions were removed to determine wall loss. The sample sites were also inspected prior to removal with non-destructive guided wave testing. Guided wave testing is designed to detect the magnitude and location of wall loss on buried pipe. Removed samples will also be inspected at the EMEC laboratory for condition and to validate the effectiveness of this technology. All removed samples were replaced with new service extensions with anodes. The condition of removed samples will be used to understand if there are correlations with factors such as age and type of ground cover.

5.5.6.1.2 CONDITION FINDINGS

The cathodic protection survey determined that there was some correlation between age and cathodic protection status (see **Figure 5.5-15**). Newer installations were more likely to be cathodically protected.

The results of the sample survey will be used to refine a mechanical model that will determine the degradation rate of unprotected service extensions. The sampling will also validate the functionality of non-destructive guided wave technology for use in future inspections.

Material fault reports show instances where the pipe entering buildings has coating damage, as it becomes damaged when inserted through the building foundation. Cathodic protection depletes faster on pipe with coating damage, exposing it to higher corrosion rates. Older service extensions are more likely to have “T-tape” field-applied coatings, which are more likely to fail than modern manufacturer-applied coatings.

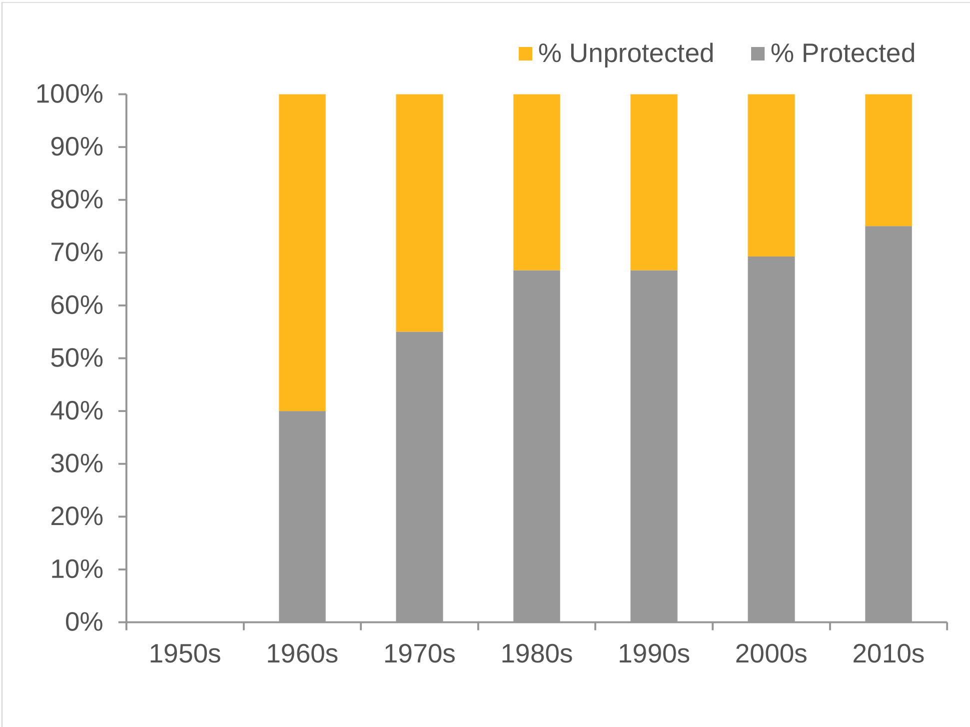


Figure 5.5-15: Percentage of Cathodic Protection on Service Extension Samples

5.5.6.1.3 RISK AND OPPORTUNITY

If service extensions are not cathodically protected and properly coated, they can corrode at a higher rate than expected, eventually leading to a loss of containment if not remediated. Since this piping enters the building below grade, gas leaks may have a higher chance of migration into the building, resulting in gas accumulation and a potential incident. The sample survey shows that the proportion of service extensions without cathodic protection increases with age. This may be due to old installation requirements and depleted anodes over time.

Historical frequencies of failures for service extensions are low relative to the total population. Failure consequences can be high as underground gas can possibly migrate into a building. However, since service extensions operate at low pressure, corrosion leaks start out as pinholes. As natural gas is odourized, leaks are likely to be detected and remediated before a hazardous indoor gas concentration is reached.

The safety risks identified for service extensions are gas leaks and gas migration. Identified financial risks include unplanned repair and relight costs, commodity loss, and property damage caused by gas leaks. Customer satisfaction risks are largely related to service interruptions and reputational damages.

The overall risk of service extensions is in a broadly tolerable range based on conservative and best available data for the total population.

5.5.6.1.4 STRATEGY

Section 3.2 of *CSA Z662 - Oil and Gas Pipeline Systems* requires an integrity management program for pipeline systems. This includes knowing the condition of these assets, assessing the risk of failure, and reducing risk to an acceptable level. Meter readers have conducted comprehensive surveys to verify the location of these assets. In addition, leak surveys include inspections for leaks up to the meter. Based on risk being in a broadly tolerable range, the strategy is to opportunistically replace service extension assets in conjunction with planned and unplanned service replacements and planned city sidewalk/road replacements.

In parallel, these assets will be added to the Corrosion Monitoring program. Condition data will be collected over time, refining the failure model to more accurately predict the end-of-life of these assets. In addition, current EGD policy requires adequate cathodic protection to be installed at the time of service extension installation.

Should the risk profile increase beyond the broadly tolerable range based on modeling updates, a proactive approach of inspection and remediation will be considered. The collection of installation, condition, failure, and maintenance data on the majority of the service extension population can be used to validate high-risk location criteria, reduce risk in a priority that is supported by data, and refine the remediation/inspection program pace.

This strategy will minimize safety risk by remediating integrity issues before they turn into failures. This will minimize the financial impact of responding to related emergency calls. The opportunistic approach minimizes costs associated with proactively renewing these assets. From a customer satisfaction perspective, this approach will improve on the current level of operational reliability.

5.5.6.2 Multi-Family Building Services

Multi-family building installations differ from typical installations significantly by having company-owned pipe within a building. The buildings are typically multiple-storied and contain many independent premises, each with their own meter installed either ensuite or in a rack of meters within the building. These buildings can also be multi-family occupied town housing or row housing.

This piping can contain pressure regulated by a sales station or a low pressure delivery regulation set. With ensuite configurations, the network of EGD-owned piping is extensive, as it includes all of the piping leading to each meter on different floors of the building. With racked metering configurations, company-owned piping typically terminates in a common area such as the garage level where individual customer meters are grouped together.

Multi-family building installations have a number of challenges:

- Code allows for these buildings to have higher pressure gas than a single family residential unit.
- Piping location creates challenges for leak surveys and cathodic protection surveys.
- Some units may have isolated steel pipe upstream of the meter.
- Density of the units means potential incidents can have a greater impact.

The Leak Survey and Cathodic Protection Survey program currently includes 888 of these multi-family buildings for survey once every three years. Their inclusion is based on records identifying them as vertical subdivisions (multi-family buildings four stories and greater). As of 2018, the design standard scope has been broadened to include multi-family buildings with no limitation on the number of storeys. A system extract based on residential customers and two or more inside meters indicates that there may be as many as 2900 locations. The intent of this broad extract is to identify additional in-scope sites (such as row-housing with internal headers) that were previously out of scope and not included in the integrity management programs.

Figure 5.5-16 shows the distribution of vintages, as well as the distribution of inside meters per building at these potential locations.

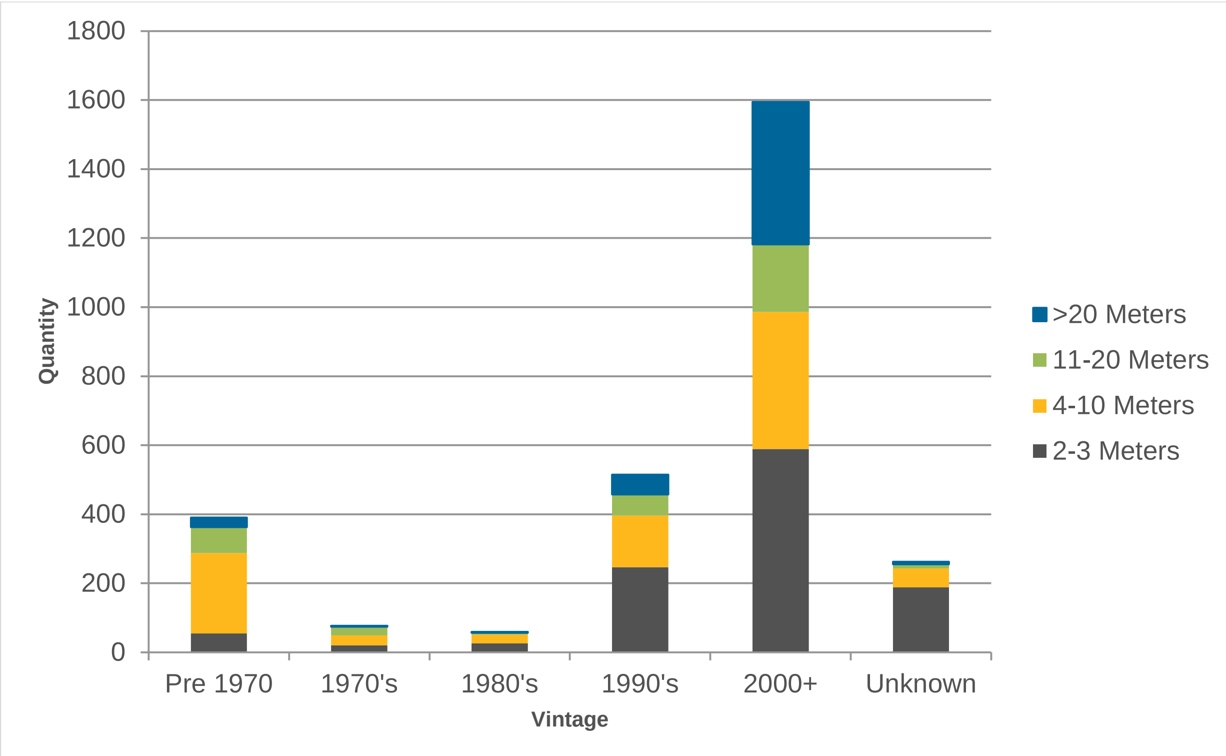


Figure 5.5-16: Multi-family Installations Vintage Distribution

The scope expansion of the multi-family buildings design standard also affects the scope and locations included in the leak survey program. Any buildings with internal distribution piping and not on the leak survey list most likely have not been inspected for leaks and condition issues since installation. If this internal piping is in poor condition, not physically supported properly, or damaged, there could be a loss of containment and gas accumulation within the building, making an incident possible.

5.5.6.2.1 CONDITION METHODOLOGY

Two main condition categories were evaluated for multi-family building services:

Adherence to Installation Specifications

- Proper support for piping by approved bracketing and minimum spacing
- Proper support and spacing of meters
- Meter location: fit for purpose, vulnerability to damage, ventilation grille if enclosed
- Identification markings per code
- Pipe penetration through walls and floors and the provision of insulating fittings
- Valve location and accessibility
- Physical barriers: existence, location, and condition

Corrosion

- Presence of corrosion on piping
- Presence of corrosion on joints
- Pipe penetration through walls, floors, and into the building
- Presence of corrosion on valves
- Adequate corrosion protection

An Integrity Assessment will evaluate failure modes and historical failures of multi-family building service components. Two surveys are required – one survey will determine which premises from the data extract are in scope. Any in-scope premises identified will be added to the leak survey program. Another sample survey will provide a collection of condition data that can statistically represent the greater population.

5.5.6.2.2 CONDITION FINDINGS

A multi-family building can consist of a garage and/or vertical headers. A system search for leak incidents with headers and header stations shows 250 related calls between 2007 and 2015. This number potentially includes headers that are out of scope. Ongoing improvements of system records and failure classifications will better refine this data specific to internal piping.

5.5.6.2.3 RISK AND OPPORTUNITY

If internal piping is in poor condition, not physically supported properly, or damaged, there could be a loss of containment and gas accumulation within the building, making an incident possible. Buried piping from outdoor regulators to indoor meters is also at risk of leaking and migrating gas indoors. Since this piping system category is located inside high occupancy buildings, the consequence of failure is high. Loss of containment will impact more people, resulting in a greater probability of personal injury. The historical frequency of incidents related to multi-family building services is low relative to the total population. However, the safely risk increases without identifying and including these assets in programs that monitor condition, prevent failure, and minimize impact of failures.

The safety risks for multi-family building services are gas leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and potential incidents. The financial risks identified are losses due to repair costs, commodity loss, relighting customer gas appliances, and any property damages caused by a gas leak. Customer satisfaction risks identified are GHG emissions, environmental impacts, service interruptions, and reputational damages.

Tacit knowledge suggests that there could be potential integrity issues that could develop into potential indoor loss of containment risks in the future. EGD is taking steps to gather necessary information to better manage these assets and their risks.

5.5.6.2.4 STRATEGY

The strategy consists of refining the total population for inclusion in existing Corrosion and Leak Survey programs, as well as understanding the condition of these assets. Adequate corrosion protection and adherence to installation specifications are required to maintain good condition. Surveys to refine population data and understand asset condition will be prioritized based on asset vintage and number of inside meters on-site. Trends between condition issues and factors such as service vintage and number of inside meters (based on building size and configuration type) will be drawn where applicable.

By validating that these premises meet the requirements for inclusion in integrity management programs, premises that have not previously been inspected will be added. The sample condition assessment will determine the extent of condition issues for these premises. Data will be used to quantify risk, and to determine if existing programs can effectively mitigate these risks. If the risks cannot be managed within the scope and timing of existing programs, a targeted remediation program will be created to address issues identified.

For all sites already identified and confirmed as multi-family buildings, the assets will continue to be monitored through integrity management programs.

This strategy manages safety risk by remediating all discovered compliance and integrity issues before they turn into failures, minimizing the risk to the safety of customers, employees, and the public. Data collected from the surveys will be used to address financial risk by proactively getting ahead of failures, minimizing the financial impact of responding to emergency calls. This proactive strategy ensures that failures are prevented, minimizing customer outages and maintaining a reputable standing as a gas provider. This strategy aims to improve on the current level of operational reliability.

This strategy also provides condition data over time that will be used to produce a failure model and more accurately predict the end-of-life of these assets. Tacit knowledge will be used to determine condition criteria. The collection of installation, condition, failure, and maintenance data on the population will then be used to validate high-risk location criteria, reduce and prioritize risk supported by data, and refine the remediation/inspection program pace.

5.5.6.3 Bulk Meter Headers

Some premises that have multiple buildings or suites are served natural gas through a common meter set, where the meter measures the consumption of all buildings or suites collectively (“bulk meter”). Gas pressure may be reduced at either the same location as the bulk meter, or it may be regulated elsewhere downstream in the system, possibly even at each suite or building.

Examples include:

- Multi-family buildings/townhouses
- Farms equipped with multiple fans for crop drying
- Academic/Assembly/Industrial/Military campuses
- Shopping malls or plazas

An example of this type of configuration is shown in **Figure 5.5-17**. In this example, note that the piping downstream of the bulk meter operates at intermediate pressure, the same pressure as the gas main serving the bulk meter.

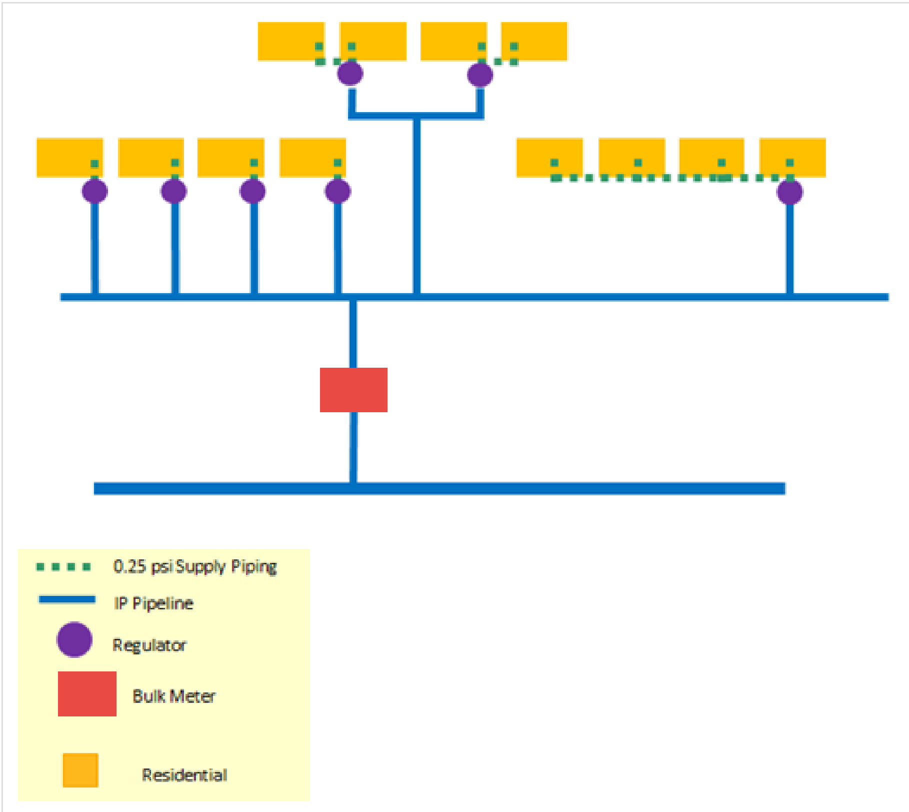


Figure 5.5-17: Bulk Meter Header Sample Configuration

5.5.6.3.1 CONDITION METHODOLOGY

Eighteen multi-residential locations with bulk meters were inspected to determine the existence of the following condition factors:

- Obsolete regulators 20 years and older
- Inside regulation
- Riser corrosion
- Lack of maintenance and plant oversight for more than 15 years, as per records
- Evidence of unreported third-party damage
- Above ground copper loops
- Compression fittings
- AMP fittings
- Header and service location unknown due to damaged tracer wire
- Materials and pressures not in compliance with *CSA B149.1* (downstream of the meter)
- Adherence to current installation specifications (vent clearances and configurations, all fittings above-ground, no obsolete components)

These findings, along with site factors such as the number of units and location, will be used to prioritize remediation activities for all sites.

5.5.6.3.2 CONDITION FINDINGS

The most common condition issues found on bulk meter headers are:

- No clear demarcation point between company and customer assets
- Obsolete regulators 20 years and older
- Non-adherence to current installation and maintenance specifications (records, leak and corrosion surveys)
- Vent clearances and configurations not met, not all fittings above-ground, and obsolete components

5.5.6.3.3 RISK AND OPPORTUNITY

Historically, the probability of failure is low. However, bulk meter headers have a higher consequence of failure since the buildings serviced are higher occupancy residential units. Safety risks are related to gas leaks and migration through underground infrastructure into buildings, resulting in gas accumulation and potential incidents. The financial risks identified are losses due to repair costs, commodity loss, relighting customer gas appliances, property damages, and personal injury caused by a gas leak. Customer satisfaction risks identified are service interruptions and reputational damages.

The main driver of risk for these assets is financial, followed by customer satisfaction and safety, due to the likely outcome of a failure only requiring remediation. Compliance with the existing company policies regarding regulators keeps safety risk for these assets broadly tolerable (low) into the future.

5.5.6.3.4 STRATEGY

Bulk meter header configurations create uncertainty about the responsibility for asset maintenance. As a result, many of these sites may not have been maintained since installation. Exclusion from maintenance/replacement programs may also have resulted in the lack of appliance inspections. The strategy for this asset is to clarify the delineation point between EGD- and customer-owned assets.

Operations will review each site, proposing changes in delineation and any necessary retrofitting of the piping system as required. Engineering will review the changes, provide final approval, and document the changes in the system. These data improvements will also ensure EGD-owned assets are included in the relevant integrity management programs. This also allows EGD to communicate and follow up with the customer on the required maintenance of the systems they own.

The majority of remediation work required includes regulator replacements, riser repair and replacements, with some sites requiring full header relays.

The program will first focus on multi-residential premises with bulk meters. Based on the residential customer type, these sites are least likely to have been maintained since installation. Beyond five years, remaining sites will be remediated (if required) with corresponding customer communication.

5.5.7 Customer-owned Systems

Customer-owned systems are assets that are owned and maintained by the customer and located downstream of EGD-owned assets. Despite not owning these assets, EGD strives to obtain condition information to ensure public and employee safety, as well as to minimize the risk of consequential damage and impacts to connected EGD assets.

These systems may consist of:

- **Customer-owned Piping**: refers to the gas piping or tubing downstream of the meter outlet tailpiece. This piping or tubing extends from the meter outlet tailpiece to customer appliances.
- **Service Jumpers**: refers to a specific type of customer-owned pipe installed from an outside meter to inside the building. Its entry through the building is below-ground.
- **Customer Appliances**: refers to gas appliances using gas delivered by EGD. Typical appliances include furnaces, water heaters, gas ranges, and fireplaces.

Customer-owned piping and appliances are designed to carry and operate on pressures ranging from pounds delivery to low pressure gas. Failure of these components can cause loss of containment and appliance malfunction, resulting in safety risk to customers and the public.

EGD must comply with *Ontario Regulation 212/01*, *clause 16 b) Supply of Gas*, which states:

> *"No distributor shall supply gas to premises unless the distributor is satisfied that the installation and use of the appliance or work comply with this Regulation and the distributor has inspected the appliance or work in accordance with a Quality Assurance inspection program."*

EGD inspects customer-owned assets at the time of initial installation and after conducting relights. This includes inspection of appliances, supply piping, venting, and combustion air systems from the customer's transfer point (typically the end of the outlet tailpiece of the meter).

Warning tags and reject tags are issued to ensure that no gas-fired appliance, accessory, or equipment is left in an unsafe operating condition. There are two types of warning tags: A-tags and B-tags. A-tags are issued to identify unacceptable conditions that present immediate hazards on existing installations. A-tags are also issued when an existing B-tag has expired. B-tags are issued to identify unacceptable conditions that are not immediate hazards during both initial installation inspections and installation re-inspections. Reject tags are issued to identify unacceptable conditions that present immediate hazards on initial installation inspections.

5.5.7.1 Risk and Opportunity

Similar to EGD-owned assets, risk assessments on customer-owned assets are being refined as part of the Plan-Do-Check-Act life cycle improvement strategy on existing programs. The outcomes of future risk assessments will be used to potentially modify policies and practices such as design specifications of the gas system, the inspection frequencies of customer-owned assets, and the parameters on allowable delivery pressures to customers. Data improvements will be made possible through ongoing data collection during inspections and analysis of warning tags.

5.5.7.2 Strategy

EGD has established a Customer Safety and Compliance Quality Management Program with a series of activities and processes framed to follow the Plan-Do-Check-Act approach. This program was implemented to monitor, maintain, and continuously improve customer safety. Top warning tag code clauses are reviewed annually and corresponding action plans are used to decrease the quantity of these tags. No capital investment is required at this time for customer-owned systems.

5.5.8 Customer Assets Capital Expenditure Summary

The summary of projects and programs under the Customer Assets asset class accounts to $450M from 2019 to 2028, as summarized in **Table 5.5-8**. The Customer Assets capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.5-8: Customer Assets Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Measurement Systems	38,126	40,749	39,328	41,973	43,558	51,512	44,097	43,694	51,527	44,500	439,065
Meter Purchases	20,621	22,828	21,353	23,592	24,688	32,408	24,948	24,245	31,454	24,432	250,570
Meter Shop Upgrades	215	225	90	110	245	20	20	20	20	20	985
MXGI Program	17,290	17,696	17,885	18,270	18,625	19,084	19,129	19,429	20,053	20,048	187,510
Regulation, Safety, and Piping	2,411	2,427	754	461	463	465	466	468	470	-	8,385
Low Pressure Delivery Meter Sets (LPDMS)	653	653	653	358	358	358	358	358	358	-	4,105
Farm Tap Program	857	857	101	103	105	107	109	110	112	-	2,461
HP/XHP Remediation	902	917	-	-	-	-	-	-	-	-	1,819
Below Ground and Internal Piping Systems	55	55	-	-	-	-	-	-	-	-	110
Service Extensions	55	55	-	-	-	-	-	-	-	-	110
Customer Owned Systems	443	400	203	203	203	203	400	400	400	400	3,257
Bulk Meters	443	400	203	203	203	203	400	400	400	400	3,257
Customer Assets Total	41,036	43,631	40,285	42,637	44,224	52,180	44,964	44,562	52,398	44,900	450,816

5.6 REAL ESTATE & WORKPLACE SERVICES

5.6.1 Real Estate and Workplace Services Objectives

The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings. Properties are categorized into regional operations and administrative centres, operations depots, and head offices. The requirements for these properties are primarily based on function, headcount, and organizational structure. The asset class breakdown is summarized in **Figure 5.6-1**.

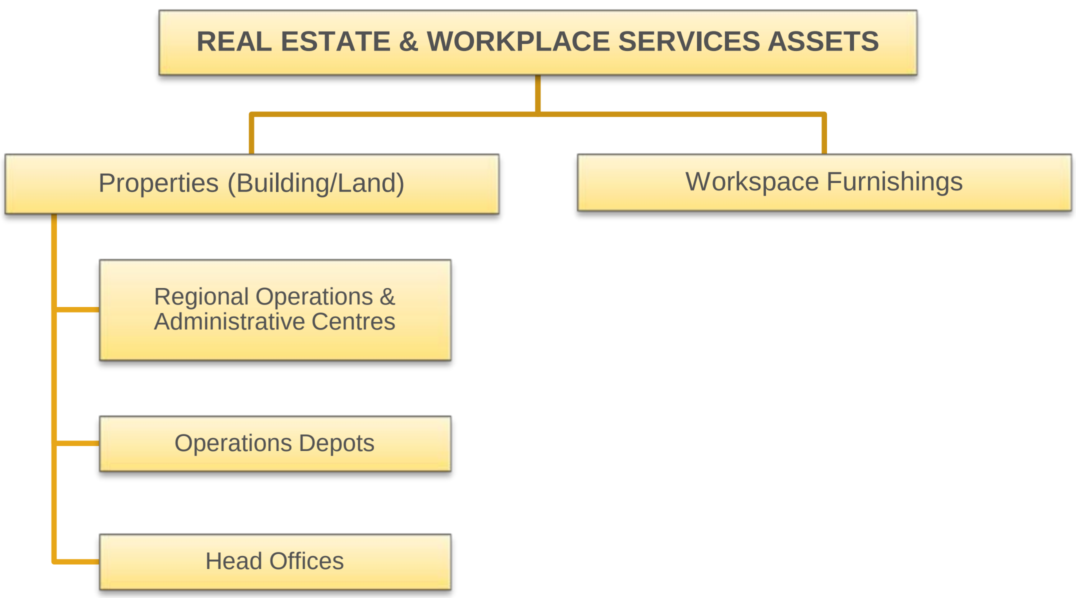


Figure 5.6-1: Real Estate Services Asset Classification

The objectives of the Real Estate and Workplace Services asset class are listed in **Table 5.6-1**.

Table 5.6-1: Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
Create and support safe, efficient and collaborative environments across EGD.	Sustain the integrity and adequacy of all facilities for safe and reliable use.	• Physical Assessment: Facility Condition Index (FCI) • Functional Assessment: Adequacy Index (AI)
	Continuously evolve the understanding of condition and risk associated with real estate assets and utilize cost, risk, and performance information to drive asset-related decisions.	• Cost per square foot (lease and building OpEx) • Utilization Rate • Risk Mitigated and LRROI • QRA completion %

To achieve these objectives, asset investment decisions are governed by the Life Cycle Management policies outlined in **Table 5.6-2**.

Table 5.6-2: Life Cycle Management for Real Estate & Workplace Services Assets

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Acquire and design facilities to suit business purposes and ensure safe business function. • Install and construct facilities to meet industry compliance and building standards. • Evaluate asset investment options to ensure best capital decisions are made for acquiring and/or creating real estate assets.
Utilize	• Suitably commission real estate assets for safe and efficient use by employees. • Monitor the use of the assets over time to understand utilization and justify future life cycle decisions.
Maintain	• Maintain the condition (integrity, longevity, and efficiencies) of real estate assets for safe and reliable continuous operations.
Renew/Retire	• Dispose assets in a manner that minimizes cost and maximizes salvage recovery. • Renew or replace real estate assets to: - Meet the changing needs of the business. - Support the health and safety of employees. - Meet or exceed regulatory compliance. - Increase efficiencies and reduce overall GHG emissions. • Evaluate the condition and performance of real estate assets to justify renewal decisions.

5.6.2 Real Estate and Workplace Services Inventory

The Real Estate and Workplace Services asset class is divided into four asset subclasses: properties, regional operations and administrative centres, operations depots, head offices, and furnishings & workstations. The inventory for Real Estate and Workplace Services assets can be found in **Table 5.6-3**:

Table 5.6-3: Real Estate & Workplace Services Asset Class Inventory

ASSET SUBCLASS	QUANTITY
Properties (Buildings/Land)	16
Regional Operations & Administrative Centres	3
Operations Depots	12
Head Offices	1
Workspace Furniture	~2,400

5.6.3 Real Estate and Workplace Services Condition and Strategy Overview

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M^2)	BUILDING AREA (SF/M^2)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
Kennedy (Operations Centre)	58	3.4/13,759	20,428/1,897	Owned	Building operation impacted by the physical separation of the office and warehouse. The building does not meet Ontario Building Code (OBC) barrier-free accessibility and universal design standards. Some staff sit at the mezzanine level, which has a low ceiling, no natural light access, and space constraints. 100% of the furnishings are not compliant with EGD standards. The facility's current condition is considered not correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Hindered operations and administrative functions *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Kennedy Road Expansion**: Acquire adjacent property and build a new facility on the combined site.
Station B (Operations Centre)	50	3.2/12,950	6,744/626	Owned	The building is too small to accommodate current staff and does not meet OBC barrier-free and universal washroom standards. At this facility, 100% of the furnishings are not compliant with EGD standards. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Lack of dedicated operational area *Financial Risk:* Hindered operations and administrative functions *CSAT Risk:* GHG emission and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Station B New Building Construction On Existing Site**: Build a new two-storey building while maintaining the area of the existing yard.
Kelfield (Operations Centre)	58	1.04/4,209	7,381/685	Owned	EGD staff do not have access to daylight and views. The building does not meet OBC barrier-free accessibility and universal washroom standards. The building is too small to accommodate required uses. 100% of the furnishings are and not compliant with EGD standards. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents *Financial Risk:* Inefficient energy consumption, hindered operations and administrative functions *CSAT Risk:* GHG emission and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Kelfield Facility Site Acquisition and New Building Construction**: Increase the site area by acquiring the abutting property and building a new two-storey facility, increasing the existing yard size.
Brampton – Colony Court (Operations Centre)	20	3.0/12,139	13,607/1,264	Owned	EGD staff do not have access to daylight and views. The building does not meet OBC barrier-free accessibility and universal washroom standards. The warehouse is not properly equipped for efficient operation. 6% of the furnishings are compliant to EGD standards. 94% is non-compliant. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption, hindered operations and administrative functions *CSAT Risk:* GHG emission and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Brampton Facility Expansion**: Correct physical and functional deficiencies by expanding the existing facility on the existing site.
Brockville (Operations Centre)	48	1.15/4,654	3,998/371	Owned	The building is too small to meet requirements and office space lacks needed amenities. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings are not compliant with	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents *Financial Risk:* Inefficient energy consumption, hindered operations and administrative	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements.	**Brockville Facility Relocation**: Sell the existing property and purchase a property suitable in size to accommodate the required program.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M²)	BUILDING AREA (SF/M²)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
					EGD standards. The facility's current condition is considered not correctable at the current location.	functions *CSAT Risk:* GHG emissions and environmental impact	The furniture maintenance schedule is reactive.	
Thorold (Regional Operations & Administrative Centre)	26	8.14/32,979	83,302/7,739	Owned	EGD staff do not have access to daylight and views. The building does not meet OBC barrier-free accessibility and universal washroom standards. 9% of the furnishings are compliant to EGD standards. 91% is non-compliant. The facility's current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents *Financial Risk:* Inefficient energy consumption *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Thorold Facility Renovation and Parking Lot Expansion**: Correct physical and functional deficiencies by completing an interior renovation and expanding the parking lot to alleviate existing deficiencies.
Oshawa (Operations Centre)	29	3.89/15,742	12,050/1,119	Owned	The building is too small to meet requirements. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings are not compliant with EGD standards. The facility's current condition is considered not correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption, hindered operations and administrative functions *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Oshawa Facility Renovation** : Correct the physical and functional deficiencies by renovating and renewing the existing facility on the existing site.
Ottawa-Coventry (Regional Operations & Administrative Centre)	53	4.93/19,951	77,210/7,173	Owned	The building footprint is too large and has a complicated layout, contributing to decreased staff productivity and efficiency. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings are legacy and not compliant with EGD standards. The facility's current condition is not considered correctable at the current location, however, consolidation with the South Merivale Operations Centre (SMOC) is recommended to eliminate service coverage area duplication.	The property has been assessed to have the following risks: *Safety Risk:* motor vehicle incidents *Financial Risk:* Excessive footprint, high operating costs *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Ottawa-Coventry and SMOC Consolidation**: Sell the existing properties and purchase a property suitable in size to accommodate the SMOC and Coventry Road programs.
South Merivale Operations Centre (SMOC)	23	3.98/16,129	26,732/2,483	Owned	The site and building shared with another tenant. Site function is inefficient. The building does not meet OBC barrier-free accessibility and universal washroom standards. The facility's current condition is considered correctable at the current location, however, consolidation with the Coventry Road office is recommended to eliminate service coverage area duplication. 27% of the furnishings are compliant to EGD standards. 73% is non-compliant.	The property has been assessed to have the following risks: *Safety Risk:* Pedestrian injuries *Financial Risk:* Excessive footprint, high operating costs *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	
Peterborough (Operations Centre)	37	1.12/4,569	5,720/531	Owned	This building and site are too small to meet requirements. The building does not meet OBC barrier-free accessibility and universal washroom standards.	The property has been assessed to have the following risks: *Safety Risk:* Motor vehicle incidents	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life	**Peterborough Site Relocation and New Facility Construction**: Purchase a vacant property to build a new facility.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA ($ACRE/M^2$)	BUILDING AREA (SF/M^2)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
					At this facility, 100% of the furnishings are non-compliant with EGD standards. Its current condition is considered correctable at the current location.	*Financial Risk:* Inefficient energy consumption *CSAT Risk:* GHG emissions and environmental impact	for building system replacements. The furniture maintenance schedule is reactive.	
Arnprior (Operations Centre)	48	6.15/24,919	4,420/410	Owned	The building is lacking access to daylight throughout the warehouse, garage, and muster room. It also lacks proper locker and shower facilities. The building does not meet OBC barrier-free accessibility and universal washroom standards. At this facility, 100% of the furnishings are non-compliant with EGD standards. Its current condition is considered correctable at the current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption and operations *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Arnprior Facility Expansion**: Correct the physical and functional deficiencies by renovating and renewing the existing facility on the existing site.
Barrie (Operations Centre)	13	5.18/20,969	7,493/696	Leased	Reports indicate odors leak from the warehouse into office space due to lack of fume extraction arms. The building does not meet OBC barrier-free accessibility and universal washroom standards. 100% of the furnishings are legacy and not compliant with EGD standards. Current condition is considered correctable at current location.	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Inefficient energy consumption and operations *CSAT Risk:* GHG emissions and environmental impact	The landlord is accountable for core and shell maintenance activities. The current building maintenance schedule for EGD's tenanted portion of the property is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	**Barrie Facility Expansion**: Purchase the existing property in its entirety and expand into the adjacent tenant space area.
VPC (Head Office)	51	15/60,703	348,787/32,403	Owned	On unrenovated floors, EGD staff have insufficient access to daylight and views. The lack of an adequate number of elevators causes delays and productivity loss. The building envelope is more than 50 years old. A pending engineering study was proposed to assess core and shell condition. The emergency power generator onsite is obsolete and a program is in place to replace it. 86% of the furnishings are compliant to EGD standards. 14% is non-compliant. The facility's current condition is considered correctable at the current location. The Mechanical Services Building was built in 1969 and is no longer capable of accommodating the volume and specialized needs of the operation.	The property has been assessed to have the following risks: *Safety Risk:* Building envelope failure *Financial Risk:* Inefficient energy consumption, operations and advanced age *CSAT Risk:* GHG emissions and environmental impact	The current building maintenance schedule is proactive for preventative maintenance and proactive at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	VPC strategies include: • **VPC Facility Renovation**: Correct physical and functional deficiencies by renovating and renewing the facility on the existing site. • **VPC Emergency Life-Safety Systems Backup Power Replacement** • **VPC Core and Shell Obsolescence Study** • **New Mechanical Services Building Build-out**
TOC (Regional Operations & Administrative Centre)	7	11.1/44,920	99,620/9,255	Owned	This facility is relatively new and meets EGD standards. The Engineering Materials Evaluation Centre (EMEC) requires additional space to adequately operate for its designed function. 100% of the furnishings are compliant to EGD standards and there are no plans to replace	The property has been assessed to have the following risks: *Safety Risk:* Nominal *Financial Risk:* Third-party laboratory expenses *CSAT Risk:* None	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance	**TOC Facility Expansion**: Expand the laboratory and warehouse facilities in the EMEC for required operations.

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M^2)	BUILDING AREA (SF/M^2)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
					furniture.		schedule is reactive.	
Tecumseh Engineering (Operations Centre)	9	4.8/19,425	10,695/993	Owned	This facility is relatively new and meets EGD standards. 100% of the furnishings are non-compliant with EGD standards.	None.	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	Maintain existing facility.
Tecumseh Gas Storage (Operations Centre)	2	10/40,469	41,817/3,884	Owned	This facility is brand new and meets EGD standards. 100% of the furnishings are compliant to EGD standards and there are no plans to replace furniture.	None.	The current building maintenance schedule is proactive for preventative maintenance and at end-of-life for building system replacements. The furniture maintenance schedule is reactive.	Maintain existing facility.
Furniture & Ergonomics	N/A	N/A	N/A	Owned	The assets associated with furniture and ergonomic blanket include all EGD furniture assets. The blanket addresses office and meeting room furnishings and ergonomic requirements. Benefits of the furniture program: • Ergonomic support • Daylight and views for building occupants through the use of mid-height panel systems • Task seating to address a range of body types • Consistent workstation configuration • Lower operating costs by contributing to fixed environments that allow a broad range of administrative requirements without change	Without adequate furniture and ergonomics in place, EGD is exposed to financial risk as productivity can potentially suffer due to inefficient space allocation and unnecessary workstation re-configuration costs. Improper ergonomics support can pose a safety risk as lack of task seating that addresses a range of body types and requirements can potentially cause repetitive strain injuries.	N/A	The renewal /replacement strategy for furniture and ergonomics assets is to replace office and meeting room furnishings as required due to failure, ergonomic modifications, and tools as recommended by an ergonomist and/or the EGD Health Centre for the prevention of repetitive strain injuries and the needs of return-to-work employees.
Cabling	N/A	N/A	N/A	Owned	The assets associated with cabling projects include all cabling assets that span across the entire organization. This project covers break-replacement of defective cabling infrastructure as well as new cable installations.	If cabling systems are not maintained as needed, it potentially poses a financial risk to EGD due to a loss of productivity stemming from the loss of connectivity to EGD's networks and systems.	N/A	The renewal /replacement strategy for cabling assets is to maximize asset useful life and replace cabling upon failure. The nature of the work involves the replacement of non-functioning and new data cabling.
Workplace Transformation	N/A	N/A	N/A	N/A	Current office layouts are not supportive of an activity-based environment and require renovation to create workspaces with increased utilization by having fully unassigned seating and over-assignment of staff to ensure a high utilization rate of workspace assets.	Inefficient use of workspaces poses a financial risk to EGD as inadequately used space can potentially lead to higher costs to maintain unused and unneeded space.	N/A	The renewal /replacement strategy for workspace assets is to create a flexible work environment to maximize EGD's space utilization for effective use of its facilities, fostering mobility, collaboration and productivity. EGD plans to update office environments to better suit flexible work arrangements designed with greater density,

PROPERTY/PROGRAM	AVG. AGE (YR)	SITE AREA (ACRE/M^2)	BUILDING AREA (SF/M^2)	OWNERSHIP	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	RENEWAL/REPLACEMENT STRATEGY
								shared workspaces, and supporting technologies.
Building Systems	N/A	N/A	N/A	Owned	A third-party engineering consulting company was employed by EGD to analyze factors such as age of equipment, maintenance records, repair cost, building standards, and compliance issues to determine overall risks and the replacement timing of heating, ventilation, air conditioning (HVAC) equipment, plumbing, electrical systems, building envelope, facilities equipment, and exterior site improvements.	If building systems are not properly maintained, there is financial risk to EGD as the failure of these systems increases substantially, which can potentially lead to loss of use and decreased staff productivity.	N/A	The renewal /replacement strategy for building systems assets is to maximize equipment useful life and replace building systems before failure, including the replacement of the building envelope, HVAC, and electrical systems to current environmental standards, ensuring interior comfort and overall security.
GHG Energy Reductions	N/A	N/A	N/A	Owned	EGD has started a third-party study on energy efficiency and emissions for its office buildings. The study identifies operational improvements needed to ensure building systems are operated efficiently to reduce natural gas use.	Existing facilities use more energy than a comparable new or renovated facility (using current OBC and energy standards), which poses the following risks: *Financial Risk*: Reduction in operating costs *CSAT Risk*: Existing facilities emit more greenhouse gases that can potentially affect ratepayers.	N/A	Existing building commissioning is underway at VPC and TOC. Planned completion is slated for 2018 to ensure retro-commissioning covers seasonal systems. The retro- commissioning process will identify a mix of measures with a range of implementation costs and energy/GHG savings. Once completed, the Retro-commissioning and Building Operations teams will develop measures and action plans for energy conservation measure implementation, verification, and ongoing commissioning. Lessons learned will be implemented on other building improvement projects.

5.6.4 Real Estate Condition Methodology (Properties & Workspace Furnishings)

For the Properties (buildings/land) asset sub-classes, a Facility Assessment is used to:

- Assess the physical condition of each facility
- Assess the operational functionality of each facility
- Identify potential gaps in service area coverage
- Create a long term real estate portfolio strategy
- Construct a “bottom-up” capital plan
- Create quality indoor environments with access to natural light and views which result in increased productivity, decreased absenteeism, and improved morale

The Facility Assessment is based on a defined set of standards representing industry best practices relating to exterior site works, architectural elements, interiors, furniture, and amenities

The Functional Obsolescence or Adequacy Index (AI) is a condition index tool used to illustrate the functional condition of the asset expressed in a percentage ratio of required functional upgrade costs divided by the replacement value of the asset to meet functional needs. Based on EGD’s standards, scores between 0% and 49% are considered good and scores of 50% and above are considered poor/critical. The AI is calculated as follows:

Equation 3: Adequacy Index Calculation

$$\mathbf{AI} = \frac{\textbf{Functional Upgrade Costs}}{\textbf{Cost to Replace the Building with its Functional Equivalent}}$$

An asset’s physical condition is assessed based on the Facility Condition Index (FCI). The FCI is a generally-accepted industry benchmarking tool. It is a scoring mechanism comparing the relative physical condition of the existing components of a group of facilities. All EGD properties have been inspected for the purpose of calculating an FCI and creating a long-term capital plan. Based on EGD’s standards, scores between 0% and 5% are considered good, 5% to 10% fair, 10% to 30% poor and greater than 30% critical. The FCI is calculated as follows:

Equation 4: Facility Condition Index Calculation

$$\mathbf{FCI} = \frac{\textbf{Cost to Remediate Immediate or Short– term Maintenance Deficiencies}}{\textbf{Current Replacement Value of Facility}}$$

Site functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area, tracked utilization, etc.) and are scored as Good, Challenged, or Obsolete. The typical yard size is 2.5 acres (the appropriateness is dependent on EGD site specific requirements).

Properties are assessed based on multiple parameters such as; site and building functional obsolescence, physical obsolescence, Ontario Building Code (OBC) compliance, and renewal/replacement strategy costs. Each property is assigned a priority rank from highest to lowest. To attain this rank, building functional obsolescence (AI), physical obsolescence index (FCI), site functional obsolescence index, and the recommended strategy for correcting the deficiencies were considered. Higher priority is given to the facilities posing larger and more immediate financial and/or safety risk to the organization.

Compliance to current OBC requirements is factored, depending on the Part, Group, and Division each property falls under. These include (but are not limited to) barrier-free path of travel, barrier-free and universal washroom facilities. Furthermore, compliance with fire code regulations on load-bearing structure, fire resistance rating, sprinkler systems, and combustible/non-combustible construction are also considered. It is important to note that major renovations to a structure may require that area to be brought up to current OBC compliance standards, potentially requiring a substantial investment.

5.6.4.1 Property Condition Methodology

The Real Estate and Workplace Services asset condition is governed by the AI and FCI indices as well as the building-to-site-area coverage (Site Functional Obsolescence). The relationships between these metrics and how they led to a particular strategic plan in regards to the asset's future are visualized in two graphs (**Figure 5.6-2**).

The graph on the left represents the buildings' AI and FCI. The black diamond in the graph indicates the facility assessment. The green area denotes that both the physical (FCI: 0-5%) and functional (AI: 0-50%) conditions meet EGD's standards. For facilities that do not meet EGD's standards, it assesses whether the identified deficiencies are considered correctable at the current location. The corners on each graph are labeled to indicate the typical strategy for facilities that lie in that general area of the graphs. The graph on the right represents the site assessment. The green area denotes that deficiencies are correctable on the existing property. The red area indicates that relocation/land acquisition is necessary to meet EGD standards.

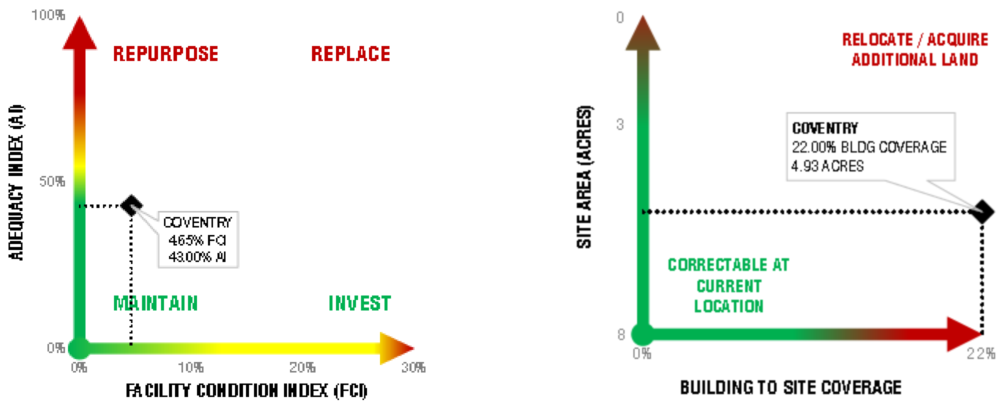


Figure 5.6-2: Sample Graphs (Coventry Road)

A facility's condition is represented in the tables below to indicate if it meets EGD standards and whether the deficiency is correctable or not at the existing property.

Physical Obsolescence: In **Figure 5.6-2**, the current FCI of the facility is 4.65%; therefore the physical condition of the facility meets EGD standards and is correctable on the current property.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: In **Figure 5.6-2,** the current facility AI index is 43%, and is considered marginally correctable at the current location without consideration of other factors (including adequacy of land size and the FCI index).

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Site: In **Figure 5.6-2**, the site does not meet operational requirements for size and vehicular circulation within the site. The yard size is smaller (1.42 acres) than EGD standard yard size requirements (2.5 acres) and is not correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

5.6.4.2 Workspace Furnishings Condition Methodology

Workspaces at each site consist of workstations and office furniture. These furnishings are either considered current (meeting EGD standards) or legacy (not meeting current standard).

Current EGD furniture standards provide:

- Ergonomic support
- Day-lighting and views for building occupants through use of mid-height workspace systems and perimeter placement
- Task seating required to address a range of body types
- Consistent workstation configuration, contributing to lower operating costs by creating fixed environments allowing a broad range of administrative requirements without change
- Designs utilizing materials and features reducing the "cubicle feel"
- Designs supporting power and network wiring

Legacy furniture (20+ years old) does not meet EGD's current condition standards. Legacy furniture is comprised of furniture systems purchased in the mid-1980s when the concept of systems furniture was first implemented. Office environment and related standards have evolved over the past thirty years. The systems still in use are high-paneled, impeding daylight into the office environments. Legacy furniture has surpassed its 10-year warranty period (the anticipated use length) and is approaching 30 years in age.

In addition, ergonomic requirements have changed to support EGD's goal of zero injuries in the office. The height of the existing fixed workstation at 29" is a contributing factor of repetitive strain injury. Current standard workstations allow for adjustable height work surfaces, empowering employees to adjust their work surface to the appropriate height or to stand if desired.

Ancillary furnishings refer to all support furnishings, including (but not limited to) guest seating, informal and collaborative areas, conference room and common space furniture, filing cabinets, and bookcases. The condition of ancillary furnishings is based on an assessment of age, physical condition, and utilization and is also evaluated as either meeting or not meeting EGD standards (legacy).

5.6.5 Coventry Road and South Merivale Operations Centre (SMOC)

5.6.5.1 Condition Findings

5.6.5.1.1 COVENTRY

The EGD-owned office building on Coventry Road, Ottawa is a facility in physically fair condition. The facility's functionality is sound but there is excess space in the building. In addition, the furniture and finishes do not meet functional standards. The office is in a good location, but there is duplication in coverage between Coventry and the South Merivale Operations Centre (SMOC).

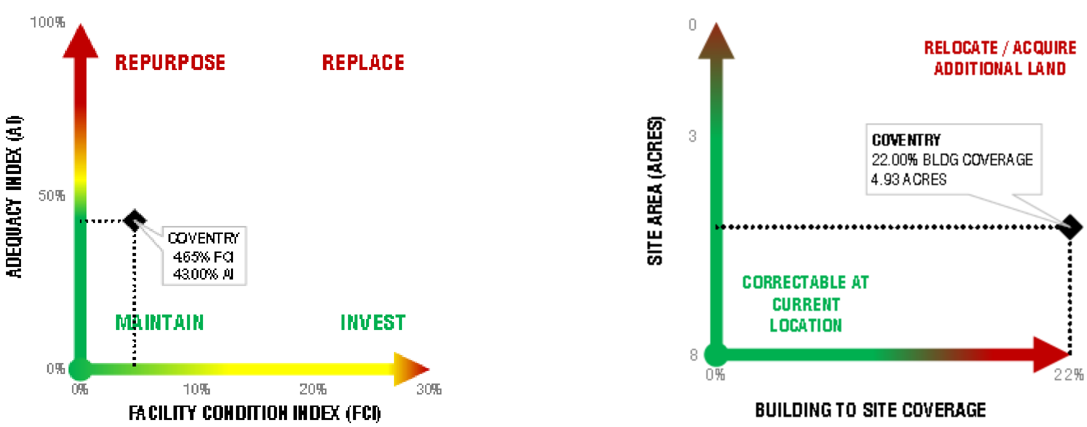


Figure 5.6-3: Coventry Facility Assessment

Physical Obsolescence: The FCI of the facility is 4.65% - the physical condition of the facility meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 43%, and is considered marginally correctable at the current location without consideration of other factors (including adequacy of land size and the FCI index).

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation within the site. The yard size is smaller (1.42 acres) than EGD standard yard size requirements (2.5 acres) and is not correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Furniture: At this facility, 100% of the furniture is legacy and therefore not compliant with EGD standards.

Relocation to another property is recommended based on site deficiencies and the lack of opportunity to increase the site area. Although the FCI/AI graph indicates a recommendation to maintain the existing facility, site deficiencies, including site space limitations and inefficiencies, preclude this option.

5.6.5.1.2 SOUTH MERIVALE OPERATIONS CENTRE (SMOC)

SMOC is an EGD-owned facility in physically fair condition. The facility's functionality is sound. However, there is excess space in the building. In addition, the furniture and finishes do not meet non-functional standards. The office is in a good location, but there is duplication in coverage between SMOC and the office at Coventry Road.

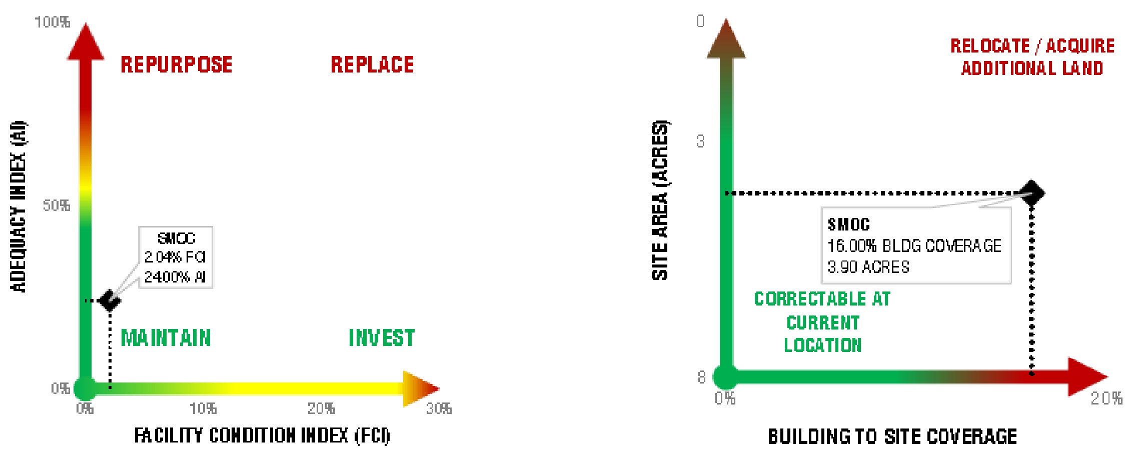


Figure 5.6-4: SMOC Facility Assessment

Physical Obsolescence: The FCI of the facility is 2.04% - the physical condition of the facility meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Building: The facility AI index is 24% which is considered correctable at the current location without consideration of other factors (adequacy of land size and the FCI index).

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Site: The yard size is smaller (1.4 acres) than EGD standard yard size requirements (2.5 acres). The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Furniture: At this facility, 73% of furniture is legacy and not compliant with EGD standards.

Based on site deficiencies and space limitations, relocation to another property is recommended. Although the FCI/AI graph indicates a recommendation to maintain and repurpose the existing facility, site deficiencies prevent the option of expanding the existing building on the same property.

5.6.5.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies at the Coventry and SMOC locations are not corrected:

- Elevated operating costs as a result of excessive building footprint
- Non-conformance to current OBC life safety, barrier-free, and universal design standards
- Inadequate parking for employees and visitors
- Site area constraints hinder vehicular circulation and increase the probability of motor vehicle incidents.
- SMOC is a shared site/building and its size and functionality promotes inefficiency.

These consequences pose the following risks:

- **Safety Risk**: inadequate yard size, hindering vehicle circulation within the site
- **Financial Risk**: increased operating costs related to excessive footprint, resulting in an inefficient use of space and productivity challenges
- **Customer Satisfaction Risk**: the existing facility emits more GHGs and uses more energy than a comparable new construction compliant to OBC and energy standards.

5.6.5.3 Strategy

The following options to address these deficiencies have been assessed:

1. Sell the Coventry site and purchase a property suitable in size (approximately six acres). Purchase an additional one acre for the SMOC site from the abutting property and correct physical and functional deficiencies through renovations.
2. Sell both existing properties and purchase a property suitable in size to accommodate the combined program of SMOC and Coventry Road. The required size of the new property is approximately seven acres.

The preferred strategy is Option 2. This option ensures that the site footprint is adequate for current activities, building deficiencies are corrected, and combines the SMOC and Coventry locations to correct the service coverage duplication currently existing between the two facilities.

5.6.6 Thorold

5.6.6.1 Condition Findings

The administrative office in Thorold is an EGD-owned property in physically good condition but operating at full occupancy, offering minimal room for growth. EGD occupies the ground floor. The second floor is occupied by both EGD and a tenant, with a space of 30,240 square feet. EGD occupies 5600 square feet. The Thorold office was last renovated 20 years ago and the environment is in need of a refresh. Since the last renovation, EGD office standards have evolved and include a focus on natural light and outdoor views. The facility does not meet current EGD office standards.

In addition, the parking lot at the Thorold administrative facility does not meet EGD standards or growth demands. The parking lot does not accommodate requirements for both operations and administrative staff parking. During peak periods, such as training sessions, department meetings, and special events, EGD staff are required to park offsite due to limited space. In the winter after heavy snow, up to 10 parking spaces are lost until the snow is hauled offsite.

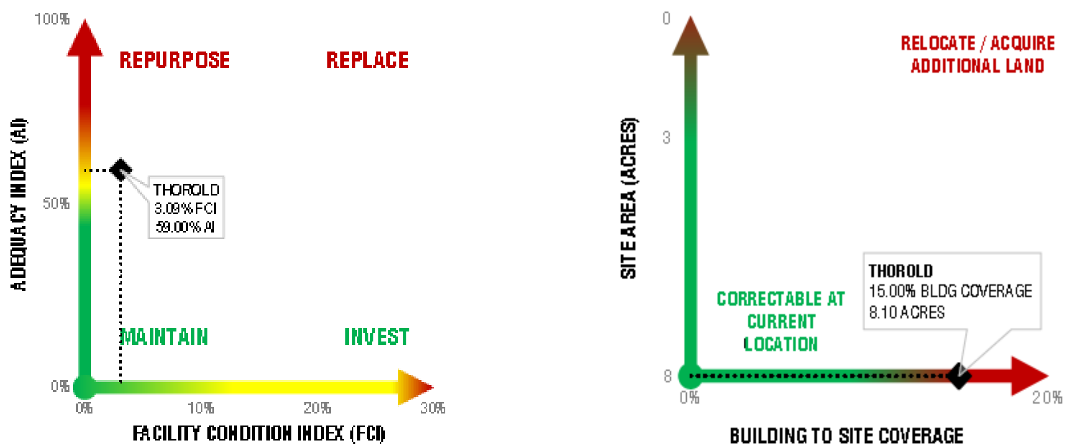


Figure 5.6-5: Thorold Facility Assessment

Physical Obsolescence: The FCI of the facility is 3.09% - the physical condition of the facility meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Building: The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGD standards. The facility AI index is 59%, which does not meet EGD standards, but is considered correctable at the current location without consideration of other factors (including adequacy of land size and the FCI index).

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Site: The site does not meet operational requirements for vehicular circulation. The yard size is smaller (1.7 acres) than EGD's standard yard size requirements (2.5 acres), however there is at least one acre of landscaped area that could be reconfigured to accommodate site deficiencies, and is therefore considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Furniture: At this facility, 91% of furniture is legacy and not compliant with EGD standards.

Overall the building does not meet EGD standards, due to lack of daylight in the office are and the safety hazards posed by the inefficient site configuration, function, and vehicle circulation in the EGD yard. It is recommended that a business study be performed to determine the best course of action. Based on site deficiencies and space limitations, reconfiguration of the existing office area and site layout is recommended. The FCI/AI graph indicates a recommendation to maintain and repurpose the existing facility.

5.6.6.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected:

- Non-conformance to current OBC life safety, barrier-free and universal design standards
- Inadequate parking for employees and visitors
- Lack of daylight in the office area

These consequences pose the following risks:

- **Safety Risk**: inadequate administrative parking impacting yard operations. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. Best practices dictate keeping industrial vehicles away from administration parking areas.
- **Financial Risk:** the existing facility uses more energy than a comparable renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk:** the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.6.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by completing an interior renovation and expanding the parking lot to alleviate deficiencies (based on the tenant remaining at the current location).
2. Sell the existing property and purchase a property suitable in size to accommodate the required program. The required size of a new property is approximately five acres (based on the tenant leaving current location).

The preferred strategy is Option 1. Physical and functional standards can be met more cost-effectively by renovating the current office space and site. Option 2 is not recommended as the land can be reconfigured to meet EGD yard standards and the building can be reconfigured to correct deficiencies and to comply with current OBC and energy standards.

5.6.7 Technology and Operations Centre (TOC)

5.6.7.1 Condition Findings

The EGD-owned Technology and Operations Centre (TOC) office is in physically good condition and offers good overall utilization. The TOC is a new facility built and operationalized approximately six years ago. One specific area requiring expansion is the Engineering Materials Evaluation Centre (EMEC) facility within the TOC. The EMEC's 10-year growth plan has been achieved within 24 months as a result of an increased focus on asset integrity. This rapid expansion was not anticipated during the facility buildout.

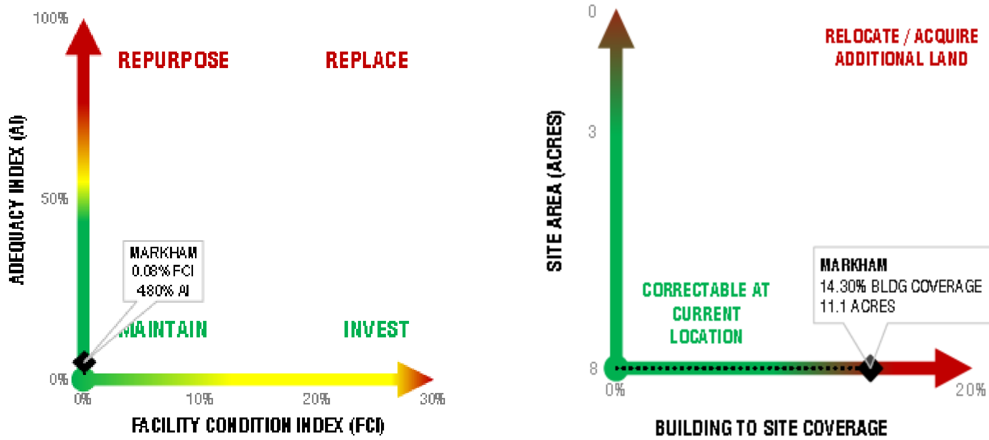


Figure 5.6-6: TOC Facility Assessment

Physical Obsolescence: The FCI of the facility is 0.08% - the physical condition of the facility meets EGD standards.

Meets Standards		**Correctable at Current Location**	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 4.80%, which meets EGD standards. The existing facility is in general compliance with EGD standards. The existing functional deficiency is a lack of adequate space affecting the operational performance of the EMEC laboratory. This deficiency is considered correctable on the existing site. An addition of approximately 3,500 square feet is required to address the current functional deficiencies of the EMEC laboratory. This will include an extension to the exiting mustering room and additional measurement and regulation laboratory requirements.

Meets Standards		**Correctable at Current Location**	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Site: No major site deficiencies were observed on site during the assessment - the facility is in general compliance with EGD standards.

Meets Standards		**Correctable at Current Location**	
Positive	Negative	**Positive**	Negative

Furniture: At this facility, 91% of the furnishings are standards-compliant. 9% are legacy and not compliant.

5.6.7.2 Risk and Opportunity

Despite the good building and site conditions, there are a number of consequences to EGD if EMEC deficiencies are not corrected:

- The current physical space does not allow for large diameter steel pipe and steel component testing.
- There is insufficient storage for testing samples.

These consequences pose the following risks:

- **Safety Risk**: The EMEC laboratory does not allow for safe work practices for large diameter pipe. Tripping hazards exist, increasing the potential for worker injuries.
- **Financial Risk**: Insufficient space in the EMEC can result in third-party laboratory testing expenses.

5.6.7.3 Strategy

The TOC is generally adequate for EGD needs and is in good physical condition. The EMEC requires additional space to correct functional deficiencies. The expansion plan is to expand on-site and to deliver 6,400 square feet of expanded laboratory and warehouse facilities for the EMEC. The estimated service life of the expanded facility is 25 years.

5.6.8 Tecumseh Gas Storage

5.6.8.1 Condition Findings

The EGD-owned Tecumseh office is in physically good condition and offers good utilization. It is a new facility built and operationalized approximately two years ago.

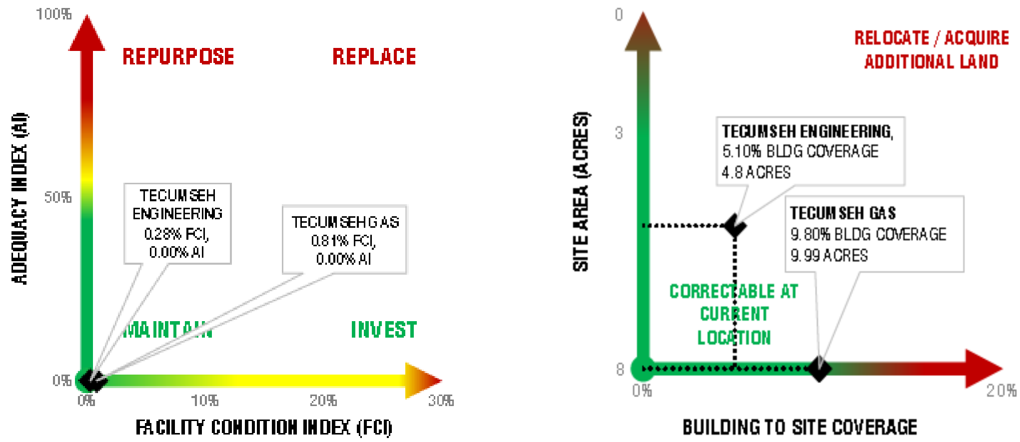


Figure 5.6-7: Tecumseh Facility Assessment

Physical Obsolescence: The FCI of the facility is 0.81% - the physical condition of the facility meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Building: The facility AI index is 0%, which is considered acceptable and meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Site: The Tecumseh Gas Operations depot and Tecumseh Engineering sites meet the functional operational requirements for size and vehicular circulation. Both buildings' yard sizes are smaller than EGD standard yard size requirements, however, both are considered to have adequate yard sizes for each building to meet operational requirements. The current yard size of the Tecumseh Gas Operations Depot is 1.7 acres, and Tecumseh Engineering is 1.2 acres.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

The existing facility meets the objectives of current EGD needs. The FCI/AI graph indicates a recommendation to maintain the existing facility.

Furniture: 100% of the furnishings are compliant to EGD standards.

5.6.8.2 Risk and Opportunity

There are no identified deficiencies or risks to note.

5.6.8.3 Strategy

The strategy for this site is to maintain the existing facility.

5.6.9 Peterborough

5.6.9.1 Condition Findings

The EGD-owned Peterborough office is in good physical condition and is considered challenged in its functionality and utilization. It is a relatively older facility with an approximate age of 37 years.

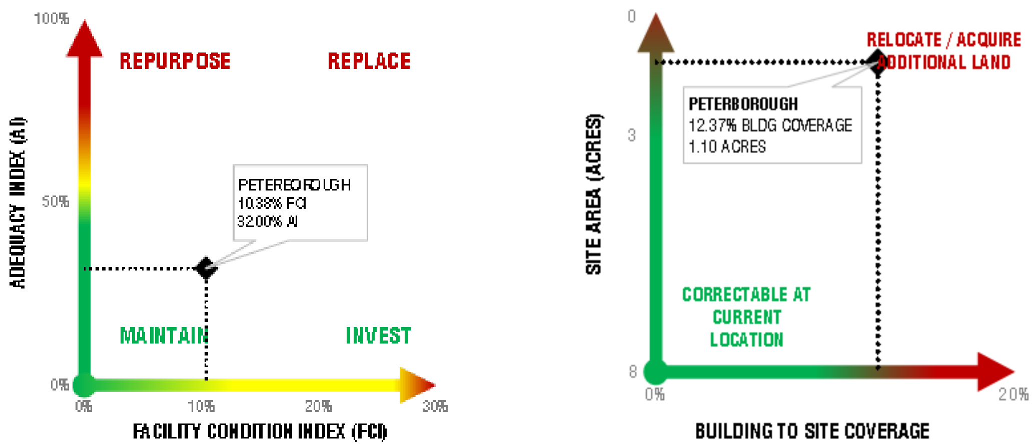


Figure 5.6-8: Peterborough Facility Assessment

Physical Obsolescence: The FCI of the facility is 10.38% - the physical condition of the facility is considered marginally fair and deficiencies are correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 32%, which meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Site: The yard size is much smaller (0.57 acres) than EGD standard yard size requirements (2.5 acres). The existing building requires expansion by approximately 3,300 square feet to meet staff and EGD functional requirements. Building additions on the property will entail further reduction in the yard and parking area, and is therefore not considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Furniture: 100% of the furnishings are legacy and not compliant with EGD standards.

Overall, the existing building is too small to meet current EGD standards. The configuration of site functions and circulation is inefficient. The yard area is too small to meet current EGD standards. Building expansion on the same property will further reduce the yard area and will cause additional pressure on parking and circulation.

Based on the site deficiencies and space limitations, relocation to another property is recommended. Although the FCI/AI graph indicates recommendation to maintain the existing facility, the site deficiencies will prevent the option of expanding the existing building on the same property.

5.6.9.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected:

- Operational requirements may not be fulfilled due to inadequate yard size.
- Site configuration is functionally inefficient.
- Inadequate parking and circulation space
- Non-conformance to current OBC barrier-free and universal design standards
- Inadequate building size

These consequences pose the following risks:

- **Safety Risk**: inadequate operations yard and inadequate administrative parking, impacting yard operations. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. Best practices dictate keeping industrial vehicles away from administration parking areas.
- **Financial Risk:** the existing facility uses more energy than a comparable renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk:** the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.9.3 Strategy

The strategy to address identified deficiencies at the Peterborough site is to purchase a vacant five-acre industrial property and build a new facility. This strategy will ensure an adequate yard area for current activities and a new building will correct the identified deficiencies.

5.6.10 Kelfield

5.6.10.1 Condition Findings

The EGD-owned Kelfield office is considered obsolete in its functionality and utilization. It is an old facility with an approximate age of 58 years.

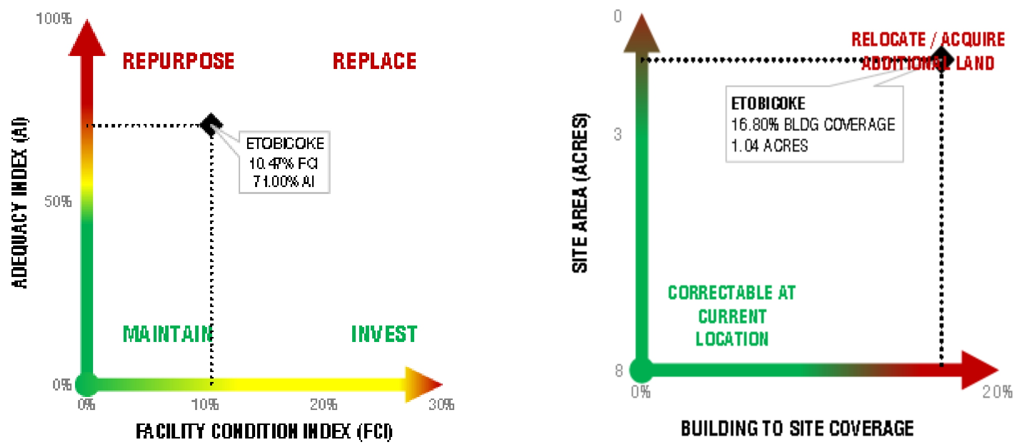


Figure 5.6-9: Kelfield Facility Assessment

Physical Obsolescence: The FCI of the facility is 10.47% - the physical condition of the facility is considered marginally fair and deficiencies are correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 71%, which does not meet EGD standards and is not correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard has only one point of access. The yard size is smaller (0.3 acres) than EGD standard yard size requirements (2.5 acres). The existing building requires expansion by approximately 7,200 square feet to meet staff and EGD functional requirements. Building additions on the property entail further reduction in the yard and parking areas, making it not correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Furniture: 100% of the furnishings are legacy and not compliant with EGD standards.

Both the building and site area are too small to meet current EGD standards. The current building is approximately 7,724 square feet and the ideal building size, based on EGD design standards, is estimated to be 14,924 square feet with a site area of approximately five acres. There is no opportunity for building expansion at the current location. It is understood that the location of the facility works well for EGD Operations. It is recommended that this facility be maintained if possible and further investigation be conducted to review a scenario where the adjacent property is purchased or the site relocated to an alternative facility in the same area, if available.

5.6.10.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected:

- Employee parking is located within the secure yard space, creating an unsafe environment within the yard.
- The building is too small to handle staff activities.
- There is little natural light throughout the office and warehouse area.
- The building is non-compliant with current OBC barrier-free and universal design standards.

These consequences pose the following risks:

- **Safety Risk**: inadequate operations yard and administrative parking. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. Best practices dictate keeping industrial vehicles away from administration parking areas.
- **Financial Risk:** the existing facility uses more energy than a comparable renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk:** the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.10.3 Strategy

The following options to address these deficiencies have been assessed:

1. Increase the site area by purchasing the abutting property (0.5 acres and building), demolishing the existing buildings, and building a new two-storey facility, increasing the existing yard size.
2. Sell the existing property and purchase a property suitable in size to accommodate the required program. The required size of new property is approximately 3.5 acres.

The preferred strategy is Option 1. This ensures adequate yard area for current activities and a new facility will correct the identified deficiencies by leveraging current improvements on site. Option 2 is not recommended but is a fallback solution if acquiring a neighboring property is not possible, as this would be a larger capital investment.

5.6.11 Kennedy Road

5.6.11.1 Condition Findings

The EGD-owned Kennedy Road facility is too small to meet current EGD standards. The separation of office and warehouse areas into two separate buildings is not convenient for staff and causes operational and workplace difficulties and inefficiencies.

The configuration of site functions and circulation is inefficient. The yard area is too small to meet current EGD standards. Building expansion on the same property will further reduce the size of the yard area and will cause additional pressure on parking and circulation. Based on the site deficiencies and space limitations, relocation to another property is recommended. Although the FCI/AI graph indicates recommendations to maintain and repurpose the existing facility, site deficiencies will prevent the option of maintaining the existing building on the same property.

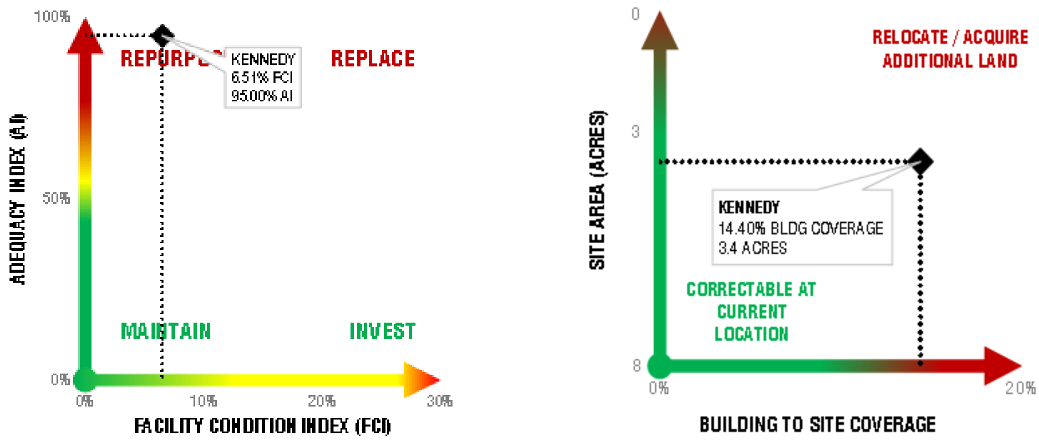


Figure 5.6-10: Kennedy Road Facility Assessment

Physical Obsolescence: The FCI of the facility is 6.51% - the physical condition of the facility is fair and deficiencies were considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 95%, which does not meet EGD standards and is not considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. Access and exit from Kennedy Road is difficult and poses operational inefficiencies.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Furniture: 100% of the furnishings are legacy and not compliant with EGD standards.

The yard size is smaller (1.3 acres) than EGD standard yard size requirements (2.5 acres). The existing building requires expansion by approximately 11,000 square feet to meet staff and EGD functional requirements. Building additions on the property entail further reduction in the yard and parking areas.

5.6.11.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected. These include:

- The building is too small and its amenities are highly inadequate for current operations.
- The mezzanine level is inadequate for current office staff.
- Offices and the fabrication shop are in two separate buildings.
- The building is non-compliant to current OBC barrier-free and universal design standards.

These consequences pose the following risks:

- **Financial Risk**: insufficient site and office areas hindering operations and administrative functions.
- **Customer Satisfaction Risk**: the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.11.3 Strategy

The following options to address these deficiencies have been assessed:

1. Purchase the adjacent property (approximately two acres) and correct physical and functional deficiencies by expanding and renovating the existing facility.
2. Buy the adjacent property (approximately two acres), demolish the existing buildings on site, and build a new facility on the combined site.
3. Sell the existing property and purchase a property suitable in size to accommodate the required program. The required size of new property is approximately five acres.

The preferred strategy is Option 2. This strategy will leverage current site improvements and keep land acquisition cost to a minimum by joining the currently vacant neighboring property.

Option 1 is not recommended because although the purchase of the additional two acres would ensure an adequate site area, the building is not correctable in its current structure.

Option 3 is not recommended as relocating to a five-acre property would incur unnecessary additional capital investment over Option 2. This is a fallback solution if the adjacent property cannot be acquired.

5.6.12 Colony Court

5.6.12.1 Condition Findings

The Colony Court office in Brampton, Ontario is an EGD-owned property and has served the Central Region West area for over 10 years. The property does not meet functionality and utilization requirements. In addition, the facility does not meet current building standards and operational requirements. The office space and yard is no longer sufficient to accommodate current and future staffing needs. Majority of the furniture does not meet non-functional requirements. The office also experiences frequent power outages.

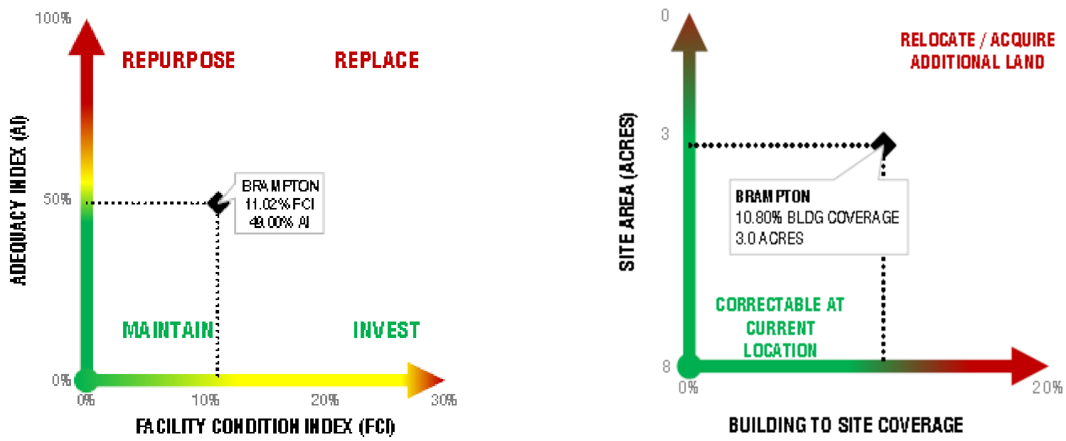


Figure 5.6-11: Colony Court Facility Assessment

Physical Obsolescence: The FCI of the facility is 11.02% - the physical condition of the facility does not meet EGD standards, however, deficiencies are considered correctable at the current location

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Building: The facility AI index is 49%, which is on the cusp of not meeting EGD standards. Deficiencies are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Site: The site does not meet operational requirements for vehicular circulation. The yard has only one point of access. The existing building requires expansion by approximately 9,000 square feet to meet staff needs and EGD functional requirements. Building additions on the property will reduce the yard and parking areas, however, the yard size will still be considered adequate based on current operations.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Overall, the existing building is too small to meet current EGD standards. The current building is approximately 14,250 square feet. An additional 9,000 square feet is required to accommodate office and industrial space. The site area is considered in general conformance with EGD size and layout requirements.

Furniture: 6% of the furnishings are compliant to EGD standards. 94% are legacy and not compliant.

5.6.12.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected:

- Site configuration is functionally inefficient.
- The building is non-conforming to current OBC barrier-free and universal design standards.
- The warehouse is too small and not properly equipped for current operations.
- Lack of daylight in the office area

These consequences pose the following risks:

- **Financial Risk**: inadequate site configuration and the lack of office and support areas hinder operations and administrative functions. The existing facility uses more energy than a comparable new or renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk**: the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.12.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by expanding the existing facility on the existing site.
2. Demolish the existing building and build a new site on the existing property.

The preferred strategy is Option 1. The site can be reconfigured to correct its deficiencies and the existing structure can be expanded and reconfigured to meet current EGD standards without the added expense of temporary accommodations and demolishing and rebuilding the existing structure. Option 2 is not recommended as the additional capital investment is unnecessary to correct identified deficiencies.

5.6.13 Tecumseh Engineering

5.6.13.1 Condition Findings

The EGD-owned Tecumseh Engineering office is in physically good condition and offers good utilization. It is a new facility that was built and operationalized nine years ago.

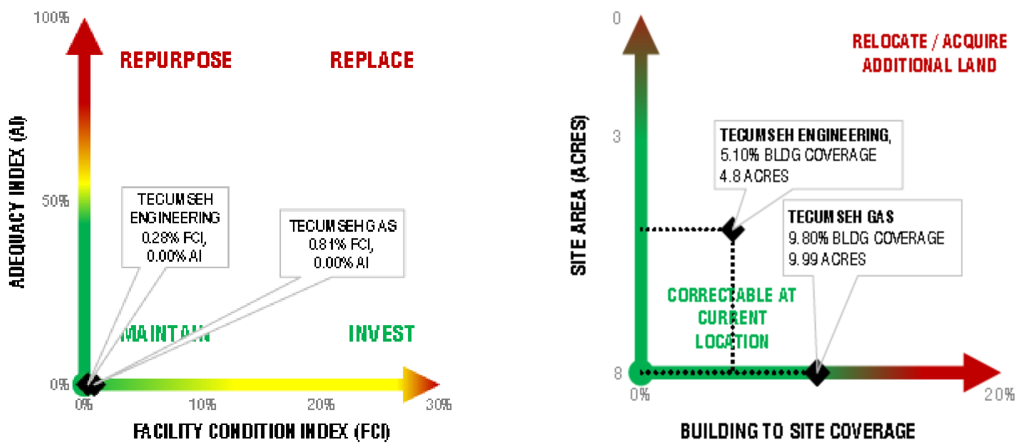


Figure 5.6-12: Tecumseh Engineering Facility Assessment

Physical Obsolescence: The FCI of the facility is 0.28% - the physical condition of the facility meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 0% which is considered acceptable and meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Site: Tecumseh Gas Operations Depot and Tecumseh Engineering sites meet the functional operational requirements for size and vehicular circulation within the sites. Both buildings' yard sizes are smaller than EGD standard yard size requirements, however, both are considered to have an adequate yard size for each building to function for the operational requirements of each site. The current yard size of the Tecumseh Gas Operations depot is 1.7 acres, and Tecumseh Engineering is 1.2 acres.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

The existing facility meets current EGD needs. The FCI/AI graph indicates a recommendation to maintain the existing facility.

Furniture: 100% of the furnishings are legacy and therefore not compliant with EGD standards.

5.6.13.2 Risk and Opportunity

There are no identified deficiencies or risks to note.

5.6.13.3 Strategy

The strategy for this site is to maintain the existing facility.

5.6.14 Station B

5.6.14.1 Condition Findings

The Station B office on Eastern Avenue in Toronto is an EGD-owned property in a good location, but does not meet current building standards or operational requirements. The office space no longer sufficiently accommodates current and future staffing needs of the facility.

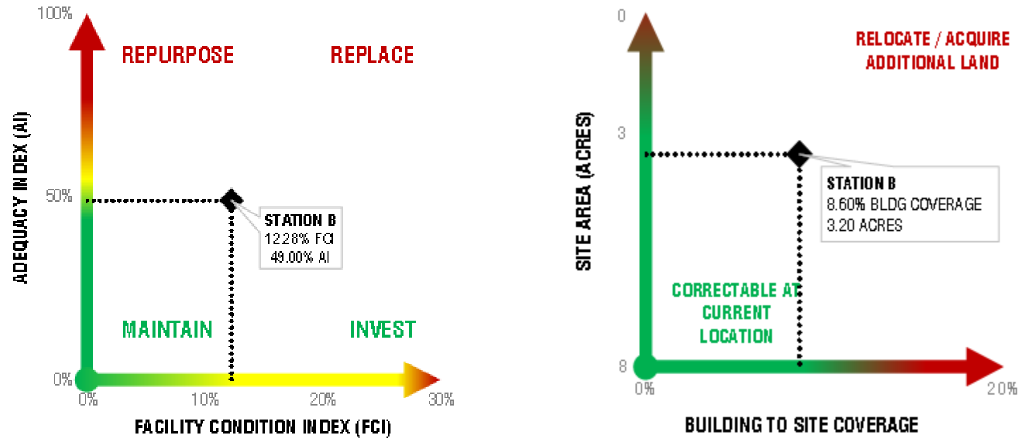


Figure 5.6-13: Station B Engineering Facility Assessment

Physical Obsolescence: The FCI of the facility is 12.28% - the physical condition of the facility does not meet EGD standards and the deficiencies are not correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Building: The current facility AI index is 49%, which is on the cusp of not meeting EGD standards. Deficiencies are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Site: The property is divided into two separate areas. One area consists of approximately 0.7 acres that is completely fenced off, including a secure gate station located adjacent to the site on the northwest corner. The remainder of the site consists of 3.2 acres and is used as an operations depot.

The site does not meet operational requirements for size and vehicular circulation. The site only has one point of access, which poses circulation difficulties and operational inefficiencies. The yard size is marginally smaller (2.25 acres) than EGD standard yard size requirements (2.5 acres). It was noted by EGD staff that the existing yard size is adequate for current operations.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

The existing building requires expansion by approximately 8,000 square feet to meet staff and EGD functional requirements. Building an addition on the property entails further reduction of the yard and parking areas. After the addition, the yard area will be reduced to approximately two acres. Vertical building expansion is recommended to prevent further yard area reduction.

The configuration of site functions and circulation is inefficient. The yard area is currently adequate to meet the operational requirements of the facility. Future building expansion on the same property will reduce the size of the yard area and will cause pressure on operations, parking, and circulation.

Based on the site deficiencies and space limitations, vertical expansion to the existing building is required to minimize the impact of the new addition on the existing yard size. Due to the high Adequacy and FCI indices (49% and 12.28% respectively), it is recommended that the existing building be demolished to allow for a new two-storey building that will accommodate current program needs. The two-storey layout allows for a reduced building footprint while maintaining the current size of the yard, allowing the deficiencies to be correctable at the current location.

Furniture: 100% of the furnishings are legacy and therefore not compliant with EGD standards.

5.6.14.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected:

- The building is non-compliant to current OBC barrier-free and universal design standards.
- Parking for employees and visitors is mixed with operations.
- Lack of daylight in the office area

These consequences pose the following risks:

- **Safety Risk**: site configuration and lack of dedicated operational area
- **Financial Risk**: inadequate site configuration and lack of office and support areas hinder operations and administrative functions. The existing facility uses more energy than a comparable new or renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk**: the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.14.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by expanding the existing facility on the existing site.
2. Demolish the existing facility and build a new two-storey building while maintaining the area of the existing yard.

The preferred strategy is Option 2. This strategy will ensure adequate yard space for operational activities. A new building also corrects the identified deficiencies, eliminating the identified risks. EGD requires a downtown site in support of operational activities - alternate site availability is limited due to required outside storage and industrial use. A proposed neighboring development reduces EGD's opportunities for expansion. On the current site, EGD's uses are grandfathered with enough yard area to accommodate requirements and continued use.

Option 1 is not recommended. As the FCI and AI indices show, the building is not correctable in its current structure and is prohibitively expensive to refurbish in order to meet EGD standards.

5.6.15 Brockville

5.6.15.1 Condition Findings

The Brockville office is an EGD-owned property that does not meet required utilization and functionality. The property is relatively old with an approximate age of 48 years.

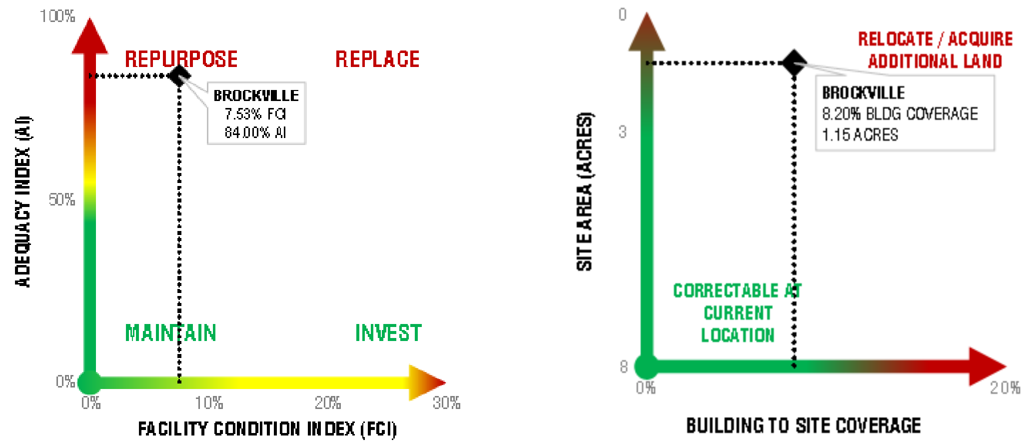


Figure 5.6-14: Brockville Engineering Facility Assessment

Physical Obsolescence: The FCI of the facility is 7.53% - the physical condition of the facility is fair and does not meet EGD standards. However, deficiencies are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 84%, which does not meet EGD standards and is not considered correctable at the current location without consideration of other factors (including adequacy of land size and the FCI index).

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard size is smaller (0.69 acres) than EGD standard yard size requirements (2.5 acres). The existing building requires expansion by approximately 6,000 square feet to meet staff and EGD functional requirements. Building an addition on the property will entail further reduction in the yard and parking areas.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Overall, the existing building is too small to meet current EGD standards. The undersized spaces, lack of proper locker rooms, lunch room, and muster room are not convenient for staff and cause operational and workplace difficulties and inefficiencies.

The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGD standards. Building expansion on the same property will further reduce the size of yard area, making it unusable and imposing additional pressure on parking and circulation.

Based on the site deficiencies and space limitations, relocation to another property is recommended. There is no opportunity to acquire adjacent lands as the site is bounded to the northwest by an Ontario Hydro transformer site, to the north by environmentally protected lands, and by roads to the southwest and southeast. There is also a gate station on site.

Furniture: 100% of the furnishings are legacy and not compliant with EGD standards.

5.6.15.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected:

- Site configuration is inefficient.
- The building is too small and its amenities are highly inadequate for current operations.
- The office space lacks needed amenities.
- The building is non-conforming to current OBC barrier-free and universal design standards.

These consequences pose the following risks:

- **Safety Risk**: inadequate operations yard and administrative parking. The mix of industrial and employee vehicles is a potential contributor to motor vehicle incidents. Best practices dictate keeping industrial vehicles away from administration parking areas.
- **Financial Risk:** insufficient site and office area hinders operations and administrative functions. The existing facility uses more energy than a comparable renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk:** the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.15.3 Strategy

The strategy to address these deficiencies is to sell the existing property and purchase a property suitable in size to accommodate the required program. The required size of new property is approximately five acres.

This strategy ensures the site footprint is adequate for current activities, building deficiencies are corrected, and that the EGD standards for both building and site coverage are met.

5.6.16 Oshawa

5.6.16.1 Condition Findings

The Oshawa office is an EGD-owned property that is in poor physical condition. The facility is challenged in its ability to meet utilization and functionality requirements but is in a good location for its workload. In addition, the existing furniture and finishes do not meet non-functional standards.

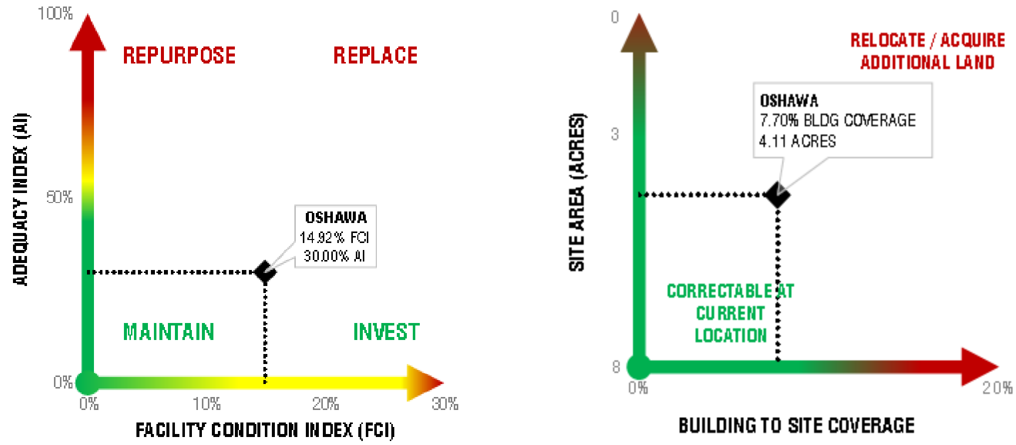


Figure 5.6-15: Oshawa Facility Assessment

Physical Obsolescence: The FCI of the facility is 14.92% - the physical condition of the facility does not meet EGD standards but is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 30% which meets EGD standards. Identified deficiencies are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Site: The yard size is smaller (1.61 acres) than EGD standard yard size requirements (2.5 acres). There is available space on the property to relocate existing parking within the yard area and increase the size of the yard to achieve a more functional space.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	**Positive**	Negative

Overall the existing building is slightly smaller than EGD current standards. To meet current standards, approximately 4,200 additional square feet is required. It is proposed that EGD expand the existing building at the current location.

Furniture: 100% of the furnishings are legacy and not compliant with EGD standards.

5.6.16.2 Risk and Opportunity

There are a number of consequences to EGD if deficiencies are not corrected:

- Inadequate for efficient current operations
- Non-conforming to current OBC barrier-free and universal design standards

These consequences pose the following risks:

- **Financial Risk:** insufficient office area hinders operations and administrative functions. The existing facility uses more energy than a comparable renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk:** the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.16.3 Strategy

The strategy is to address the identified deficiencies at the current location and correct the physical and functional deficiencies by renovating and renewing the existing facility on the existing site.

5.6.17 Barrie

5.6.17.1 Condition Findings

The Barrie office is a leased property that is in good physical condition. The facility is challenged in its ability to meet required utilization and functionality but is in a good location for its workload. In addition, the existing furniture and finishes do not meet non-functional standards.

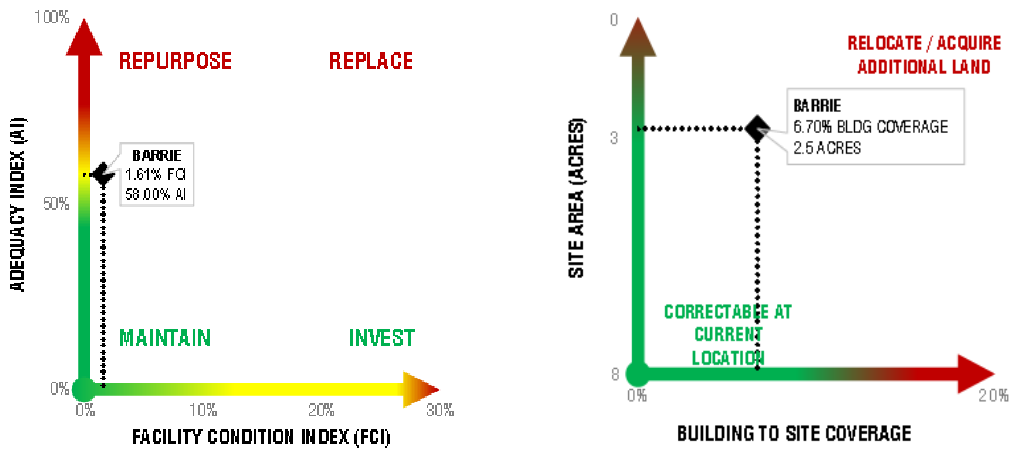


Figure 5.6-16: Barrie Facility Assessment

Physical Obsolescence: The FCI of the facility is 1.61% - the physical condition of the facility meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Building: The current facility AI index is 58%, which does not meet EGD standards. Deficiencies are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	**Positive**	Negative

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard has only one point of access.

The current yard size is 1.37 acres. EGD standard yard size is 2.5 acres. The facility is considered a satellite operations depot. Staff considers 1.37 acres as sufficient yard size for the type of operations in Barrie.

The existing building requires expansion by approximately 10,000 square feet to meet current EGD standards. A building addition on the property entails further reduction in the yard and parking areas. Current space pressures can be addressed by relocating staff to a new satellite operations depot in Orangeville and by acquiring the adjacent space currently occupied by the property landlord.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	Positive	**Negative**

Overall, the existing building is too small to meet current EGD standards. The site and building are shared with another tenant. The limited yard area allocated to EGD causes operational and workplace difficulties and inefficiencies.

The configuration of site functions and circulation is inefficient. There is only one point of vehicular access to the EGD yard. Building expansion on the same property will reduce the yard area size and will add additional pressure on parking and circulation.

Furniture: 100% of the furnishings are legacy and therefore not compliant with EGD standards.

5.6.17.2 Risk and Opportunity

There are a number of consequences to EGD if the deficiencies are not corrected:

- The site and building area are shared with another tenant.
- Configuration of site functions and circulation is inefficient.
- Odors leak from the warehouse into office space.
- The building is non-compliant with current OBC barrier-free and universal design standards.

These consequences pose the following risks:

- **Financial Risk:** building inadequacies cause operational and workplace inefficiencies. The existing facility uses more energy than a comparable renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk:** the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.17.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by expanding the existing facility on the existing site.
2. Purchase the existing property in its entirety and expand into the adjacent tenant space area.
3. Relocate from the existing property and purchase a property suitable in size to accommodate the required program. The required size of new property is approximately five acres.

The preferred strategy is Option 2. This strategy ensures adequate yard area for current activities. Expanding into the adjacent space will correct the identified deficiencies and meet EGD standards.

Option 1 is not recommended, as expansion of the existing facility would require additional capital investment in the site to make up for the portion of the site lost by the expanded building. Option 3 is not recommended as acquiring five acres and building a new facility requires additional capital investment.

5.6.18 Arnprior

5.6.18.1 Condition Findings

The Arnprior office is an EGD-owned property that is in good physical condition. The facility is challenged in its ability to meet required utilization and functionality, but is in a relatively good location for its workload. In addition, the existing furniture and finishes do not meet non-functional standards.

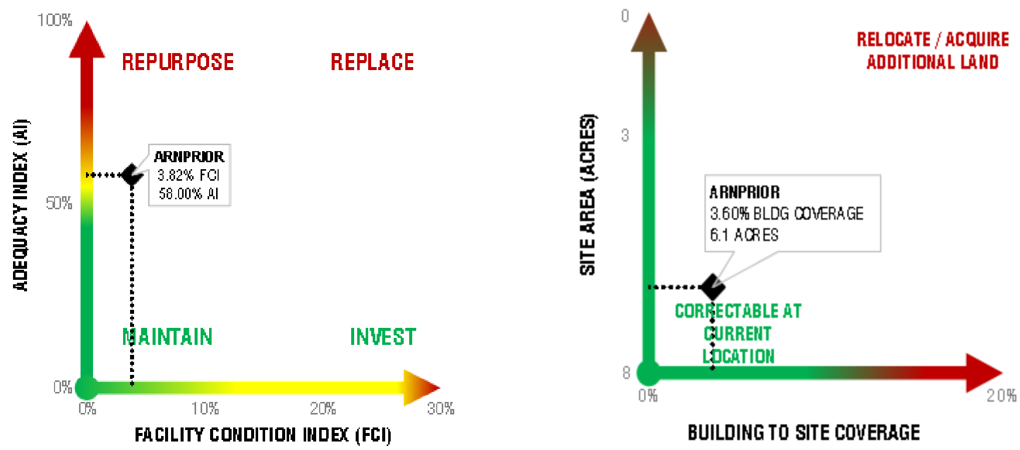


Figure 5.6-17: Arnprior Facility Assessment

Physical Obsolescence: The FCI of the facility is 3.82% - the physical condition of the facility meets EGD standards.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Building: The current facility AI index is 58%, which does not meet EGD standards. Deficiencies are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Functional Obsolescence – Site: The site meets operational requirements for size and vehicular circulation. The existing building requires expansion by approximately 5,183 square feet to meet staff and EGD functional requirements. The existing site is 6.1 acres, which meets EGD standards. There is enough space on the property to support a building addition.

Meets Standards		Correctable at Current Location	
Positive	Negative	Positive	Negative

Furniture: 100% of the furnishings are legacy and therefore not compliant with EGD standards.

5.6.18.2 Risk and Opportunity

There are a number of consequences that EGD can experience if deficiencies are not corrected:

- Building amenities are lacking, such as insufficient washrooms, and lacking lockers and shower facilities.
- Insufficient natural light throughout the warehouse, garage, and muster room.
- The building is non-compliant to current OBC barrier-free and universal design standards.

These consequences pose the following risks:

- **Financial Risk:** building inadequacies cause operational and workplace inefficiencies. The existing facility uses more energy than a comparable renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk:** the existing facility emits more GHGs and uses more energy than a comparable new construction.

5.6.18.3 Strategy

The strategy is to address the identified deficiencies at the current location and to correct the physical and functional deficiencies by renovating and renewing the existing facility on the existing site.

5.6.19 Victoria Park Centre (VPC)

5.6.19.1 Condition Findings

5.6.19.1.1 BUILDING/PROPERTY

The Victoria Park Centre (VPC) facility houses the majority of company employees. It is an EGD-owned facility that is currently undergoing renovations to address physical condition and capacity concerns as well as to replace legacy furniture and finishings. The first and second floors have not yet been renovated.

The fleet and equipment garage (Mechanical Services Building) located at VPC serves the entire GTA operations with light and medium duty fleet vehicles, heavy equipment, and tools. Fleet and equipment operations also support the installation and maintenance of NGV equipment and require substantial yard space for the maintenance, storage, and retirement of assets. The Mechanical Services Building was built in 1969 and is no longer capable of accommodating the volume and specialized needs of the operation. The expected replacement of the fleet and equipment facility delayed the expected life cycle replacements of the electrical, HVAC, building shell, overhead doors, and windows to meet current energy efficiency standards. Over the years, demand for passenger vehicle parking has also grown, limiting the parking lot capacity available for fleet and equipment operations. In addition, there are several safety issues regarding the mixed use of the VPC head office facility for both fleet and office functions on the same site. The addition of significant capital dollars to renew an inadequate and inefficient building shell on the existing site is not recommended.

The Emergency Operations Centre (EOC) meeting rooms are inadequate to house a group to respond to emergencies. Regular meeting rooms are used for this purpose and do not meet the needed Incident Command System (ICS) requirements.

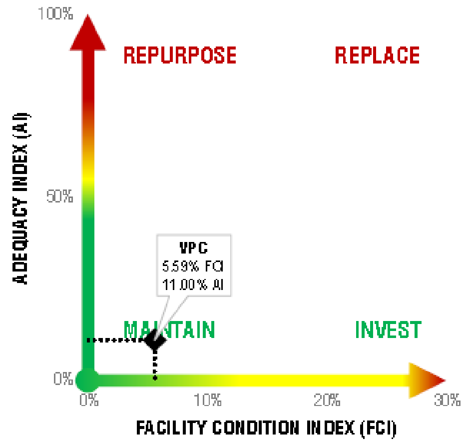


Figure 5.6-18: VPC Facility Assessment

Physical Obsolescence: The FCI of the facility is 5.59% - the physical condition of the facility is fair, however, deficiencies are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	Negative	**Positive**	Negative

Functional Obsolescence – Building: The facility AI index is 11% which does not meet EGD standards but is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	**Negative**	**Positive**	Negative

The VPC location is considered one of Toronto's more established office and commercial parks. The Sheppard subway line combined with the proximity of the area to the 401 and 404 highways have increased the interest in the area for condominium and retail redevelopment. The area is currently in the process of Official Plan amendment to permit mid- and high-rise mixed-use development with residential, retail, and other commercial uses.

Furniture: 86% of the furnishings are compliant to EGD standards. 14% are legacy and not compliant.

5.6.19.1.2 EMERGENCY LIFE-SAFETY SYSTEMS BACKUP POWER

The 590kW emergency backup power generator serves as the building's Life Safety System and serves other non-life safety portions. Life safety consists of fire panel, emergency lighting, and emergency fire systems. Other critical system loads requiring backup power include the data centre, dispatch, and telemetry systems.

The 590kW generator is 40 years old and has passed its 30-year typical useful life. Reliability is questionable and replacement parts are becoming obsolete. Its nitrogen oxide emissions are higher than accepted levels.

The 590kW generator uses a domestic cold water cooling system which is no longer industry standard and acceptable. A remote radiator will be needed to prevent the waste of water for cooling. The 590kW generator transfer switch is located in the energy plant control room which is also occupied by plant maintenance operators. It is recommended that it be located in the energy plant electrical room with a barrier.

5.6.19.2 Risk and Opportunity

There are a number of consequences to EGD if building deficiencies are not corrected:

- Deteriorating landing, stairs, and handrails throughout the sit
- Insufficient natural lighting throughout office space
- The building exterior envelope is approaching 50 years old and has a potential for envelope failure.
- Building services improvements required (two additional elevators)

These consequences pose the following risks:

- **Safety Risk**: Potential for building envelope failure. Destructive testing is planned during renovation opportunities to evaluate envelope integrity.
- **Financial Risk**: potential for loss of use without substantial life cycle improvement due to advanced age. Further financial risk is due to building deficiencies causing operational inefficiencies, leading to productivity loss. The existing facility uses more energy than a comparable new or renovated facility (utilizing current OBC and energy standards).
- **Customer Satisfaction Risk**: the existing facility emits more GHGs and uses more energy than a comparable new construction.

In addition, not replacing the obsolete emergency generator poses a financial risk as the potential failure is high, which could potentially lead to power failure, negatively impacting productivity. Critical emergency services depend on constant power so there is further safety risk due to potential for inoperable critical life safety systems. There is also risk to customer satisfaction because the data centre that houses customer data relies on constant power, as well as the dispatch and telemetry systems.

5.6.19.3 Strategy

The following options to address building deficiencies have been assessed:

1. Correct physical and functional deficiencies by renovating and renewing the existing facility on the existing site.
2. Sell the existing front section of the property (approximately 7.5 acres) and relocate the office component to the westerly section of the current site.

The preferred strategy is Option 1. This is the preferred strategy as the FCI and AI indices show the building and site deficiencies are correctable on the existing property.

Option 2 is not recommended due to the substantial additional capital investment of relocating and building a new facility on the west end of site, although building a new facility will correct all of its functional and physical deficiencies.

In addition, a two-year project is proposed to replace the 590kW generator at VPC. The total cost for the project over 2 years is $1.7M, determined based on building assessments and condition analysis. Resources are a combination of internal maintenance staff and market-sourced external providers on a project-by-project basis. Workplace Services works closely with third-party engineers, contractors, and vendors in to ensure the sustainability and energy demands of EGD’s buildings.

5.6.20 Furniture and Ergonomics

The assets associated with the furniture and ergonomic program include all furniture assets that span across the entire organization. The blanket covers break-replacement of furnishings and includes (but not limited to) workstations, offices, task seating, guest seating, informal and collaborative areas, conference room/common space furniture, filing cabinets, and bookcases.

The program covers the day-to-day purchase of furniture and ergonomic equipment and addresses office and meeting room furnishings and ergonomic requirements to support EGD’s goal of zero injuries in the office. For example, the height of an existing fixed workstation at 29” is a contributing factor of repetitive strain injury. To minimize potential workplace injuries, current standard workstations allow for adjustable height work surfaces, allowing the employee to adjust their primary work surface to the appropriate height or to stand.

Benefits of the furniture program include the following:

- Ergonomic support
- Day-lighting and views for building occupants through the use of mid-height panel systems
- Task seating required to address a range of body types
- Consistent workstation configuration
- Contribute to lower operating costs through fixed environments that allow a broad range of administrative requirements without change

The estimated service life of the new assets is 15 years.

5.6.20.1 Risk and Opportunity

Without adequate furniture and ergonomics in place, there is financial risk as productivity can potentially suffer due to inefficient space allocation and unnecessary workstation re-configuration costs.

Improper ergonomics support can pose a safety risk as lack of task seating that addresses a range of body types can potentially cause repetitive strain injuries.

5.6.20.2 Strategy

The strategy is to replace the office and meeting room furnishings as required due to failure. Ergonomic modifications and tools are issued as recommended by an ergonomist and/or the EGD Health Centre to prevent repetitive strain injuries and accommodate return-to-work employees. The annual program is based on historical spend.

5.6.21 Cabling

The assets associated with cabling include all cabling assets that span across EGD and cover the replacement of defective cabling infrastructure, new cable installations, and day-to-day cabling needs. Productivity risks are eliminated by replacing defective cable infrastructure. The budget allocated also covers new cabling infrastructure where connectivity is required. The estimated service life of the new assets is 10 years.

5.6.21.1 Risk and Opportunity

If cabling systems are not maintained as needed, this could pose a financial risk to EGD due to productivity loss stemming from loss of connectivity to EGD's networks and systems.

5.6.21.2 Strategy

The strategy is to maximize asset useful life and replace cabling upon failure. The nature of the work involves the replacement of non-functioning and new data cabling. The annual program is determined based on historical spend. Installation resources are externally contracted for cabling projects.

5.6.22 Workplace Transformation

A review of current workplace layouts versus activity-based environments is underway. Enbridge's current standard office environment is designed to create a safe, efficient workspace with daylighting and views, that harmonizes office standards enterprise-wide. The current office layouts are not supportive of an activity-based environment and require renovation to create workspaces with increased utilization by having fully unassigned seating and over-assignment of staff, ensuring a high utilization rate. The Workplace Transformation Program will renovate office space that has an activity-based focus supporting increased flexibility and collaboration. The service life of new technology assets are five years; furniture and equipment are 15 years.

5.6.22.1 Risk and Opportunity

Ineffective use of workspaces poses a financial risk to EGD as inadequately used space can potentially lead to higher costs to maintain unneeded space.

5.6.22.2 Strategy

The Workplace Transformation Program aims to create a flexible work environment to maximize EGD's space utilization, allowing for more effective use of EGD's facilities, fostering mobility, collaboration, and productivity. The program updates office environments to better suit flexible work arrangements, allowing workers to choose the type of workspace that best suit their needs. This allows EGD to improve office utilization by designing and constructing environments with greater density, shared workstations, and supporting technologies.

5.6.23 Building Systems

A third-party engineering consultation analyzed factors such as age of equipment, maintenance records, repair cost, building standards, and compliance issues to determine overall risks and timing of replacement for HVAC equipment, plumbing, electrical equipment, and exterior site improvement.

The property assessment report identifies equipment at end-of-life and recommends a replacement plan over a 25-year span. The report focused on the design, installation, and operation and monitoring of building systems required for a safe, comfortable and environmentally friendly environment for employees.

Unplanned failures occur occasionally which require immediate action. A review of each cost determines the decision to repair or replace the defective equipment. The service life of the new assets is 15-20 years.

5.6.23.1 Risk and Opportunity

If building systems are not properly maintained, there is a financial risk to EGD as failure of these systems increase substantially year over year, which can potentially lead to loss of productivity.

5.6.23.2 Strategy

The strategy for building systems assets is to maximize the equipment's useful life and replace systems before failure can cause business interruption.

The replacement of equipment is targeted but not solely specific to the building envelope, HVAC, and electrical systems. Compliance to environmental standards, interior comfort, and overall security are major considerations to ensure safe and reliable operations.

The annual program for these initiatives is determined based on historical spend as well as building assessments and condition analysis. Resources are a combination of internal maintenance staff and market-sourced external providers on a project-by-project basis. Workplace Services work closely with third-party engineers, contractors, and vendors to fulfill the sustainability and energy demands of EGD's buildings.

5.6.24 EGD-targeted GHG and Energy Reductions

Enbridge has begun a third-party study on energy efficiency and emissions from office buildings. The study identifies operational improvements to ensure current building systems are operated in an efficient manner that reduces natural gas use. The study on energy efficiency and emissions from office buildings also identifies natural gas air-sourced heat pumps and other opportunities as a potential abatement opportunity at EGD's office facilities.

5.6.24.1 Risk and Opportunity

There is a financial risk to EGD as the existing facilities uses more energy than a comparable new or renovated facility (utilizing current OBC and energy standards), increasing operating costs. There is also a customer satisfaction risk to EGD as the existing facilities emit more greenhouse gases that can potentially affect ratepayers.

5.6.24.2 Strategy

Existing building commissioning is underway at both VPC and TOC locations, planned to be completed in 2018 to ensure recommissioning covers seasonal systems. The retro-commissioning process will identify a mix of measures with a range of implementation costs and energy/GHG savings. On completion of the retro-commissioning investigation, the Retro-commissioning and Building Operations teams will develop measures, findings, and an action plan to measure energy conservation implementation. Verification and ongoing commissioning, including operational and capital improvements will also be undertaken. Lessons learned from the study will be implemented on other building improvement projects except for the following assets:

- VPC
- Colony Court
- Tecumseh Gas Storage & Engineering
- TOC
- Oshawa

The project duration is a recurring yearly program for five years. The program is determined based on building assessments and condition analysis. Resources are a combination of internal maintenance staff and market-sourced external providers on a project-by-project basis. Workplace Services works closely with third party engineers, contractors, and vendors to fulfill the sustainability and energy demands of EGD's buildings.

5.6.25 Real Estate & Workplace Services Capital Expenditure Summary

The summary of projects and programs under the REWS asset class accounts to $163M from 2019 to 2028, as summarized in **Table 5.6-4.** REWS capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.6-4: REWS Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
Arnprior	-	-	500	1,600	-	-	-	-	-	-	2,100
Barrie	-	1,000	6,000	-	-	-	-	-	-	-	7,000
Colony Court	100	3,100	-	-	-	-	-	-	-	-	3,200
Brockville	-	1,500	3,350	-	-	-	-	-	-	-	4,850
SMOC/Coventry Consolidated Facility	-	25	-	-	-	-	9,000	19,000	2,800	-	30,825
Kelfield	-	1,000	4,700	1,100	-	-	-	-	-	-	6,800
Kennedy	-	-	-	9,200	8,000	4,500	-	-	-	-	21,700
Oshawa	-	-	-	-	-	-	-	-	-	100	100
Peterborough	-	-	1,000	3,450	-	-	-	-	-	-	4,450
Station B	-	5,000	1,500	-	-	-	-	-	-	-	6,500
Thorold	-	-	-	-	-	-	200	5,800	-	-	6,000
TOC EMEC Expansion	50	50	3,500	-	-	-	-	-	-	-	3,600
VPC	2,630	4,950	7,250	4,500	-	10,000	10,000	-	-	-	39,330
Mechanical Services	-	-	4,500	4,500	-	-	-	-	-	-	9,000
VPC – 1st Floor	-	4,200	-	-	-	-	-	-	-	-	4,200
VPC – 2nd Floor	1,180	-	-	-	-	-	-	-	-	-	1,180

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
VPC - Basement	-	-	2,000	-	-	-	-	-	-	-	2,000
VPC - Link and Stairwells	-	750	750	-	-	-	-	-	-	-	1,500
VPC Emergency Life Safety Systems Backup Power	1,450	-	-	-	-	-	-	-	-	-	1,450
VPC Core and Shell Improvements	-	-	-	-	-	10,000	10,000	-	-	-	20,000
Building Systems Program	1,831	1,863	1,895	1,928	1,961	1,995	2,030	2,065	2,100	2,137	19,805
Cabling	102	103	105	107	109	111	113	115	117	119	1,100
EGD Targeted GHG & Energy Reductions	350	350	350	-	-	-	-	-	-	-	1,050
Furniture and Ergonomics	203	207	211	214	218	222	226	229	233	237	2,201
Direct Capital Overheads	530	530	530	250	250	250	250	175	-	-	2,765
REWS Total	5,796	19,678	30,891	22,349	10,538	17,078	21,818	27,384	5,251	2,593	163,376

5.7 FLEET AND EQUIPMENT

5.7.1 Fleet and Equipment Objectives

The Fleet and Equipment asset class provides EGD with the necessary vehicles, equipment, and tools to safely and efficiently run regulated business operations. EGD sustains the integrity of the fleet through a strong maintenance program, and utilizes cost analysis, risk, and performance information to drive asset-related decisions.

The Fleet and Equipment asset class consists of three asset subclasses: Fleet, Heavy Equipment and Tools. Fleet vehicles are categorized as Light Duty Vehicles (LDV) and Medium Duty Vehicles (MDV). LDVs include cars, vans, and pickup trucks. MDVs include vehicles which range from mechanic repair trucks to utility service trucks. Heavy Equipment primarily consists of backhoes, trailers, compressors, forklifts, welders, and boring equipment. The Tools asset subclass consists of all tools that support EGD's business operations, ranging from gas surveyors and concrete saws, to fusion machines and pipe squeeze-off tools. The asset class breakdown is illustrated in **Figure 5.7-1**.

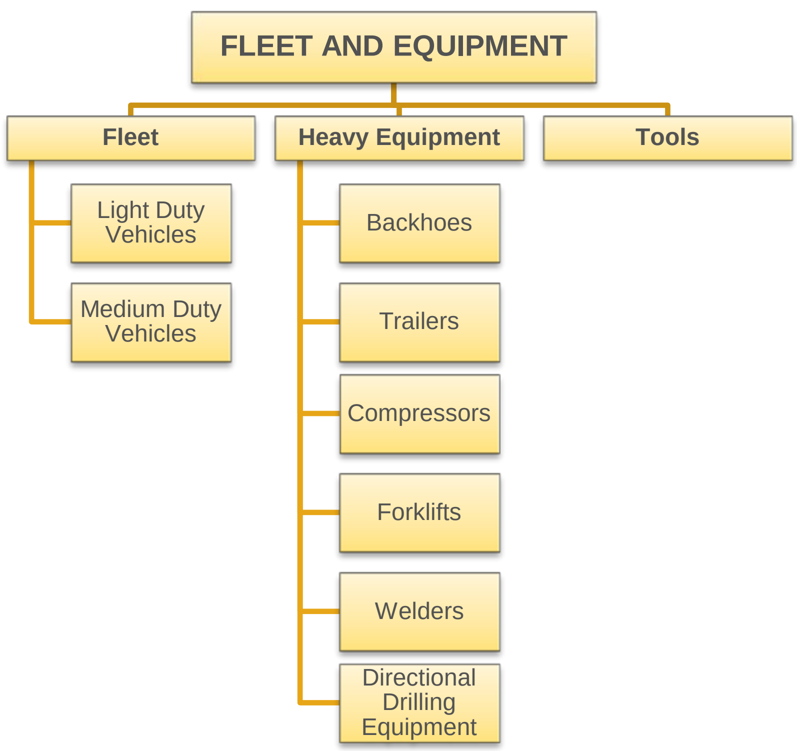


Figure 5.7-1: Fleet and Equipment Asset Class Categories

Table 5.7-1 describes the asset class objectives for Fleet and Equipment, and the corresponding measures of success.

Table 5.7-1: Fleet & Equipment Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
Supportability	Provide the business with the necessary vehicles, equipment and tools to safely and efficiently run regulated business operations.	• 100% completion of end-user requests
Integrity and Reliability	Sustain the safety and reliability of all vehicles, equipment and tools.	• Preventative Maintenance program metric • QA Closeout Rate
	Utilize cost, risk and performance information to drive asset-related decisions.	• Flagship reporting • QRA completion %

To achieve these objectives, asset investment decisions are governed by the Life cycle Management policies outlined in **Table 5.7-2**.

Table 5.7-2: Life cycle Management for Fleet & Equipment Assets

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Evaluate asset investment options to ensure prudent purchase decisions. • Acquire fleet and equipment to meet 100% of business operational needs. • Convert LDVs to operate on natural gas, reducing overall GHG emissions. • Install Auxiliary Power Units (APU) on MDVs. (An APU is an anti-idling device that reduces overall GHG emissions and prevents premature engine wear and tear.)
Utilize	• Appropriately commission vehicles, equipment, and tools to ensure safe and efficient use. • Monitor and track asset use to understand performance and inform life cycle decisions. • Optimize natural gas as a fuel source for LDVs to reduce overall GHG emissions. • Install GPS technology to optimize asset utilization.
Maintain	• Maintain vehicles, equipment, and tools to ensure safe and reliable continuous operation. • Align with manufacturer maintenance recommendations and industry best practices to achieve expected asset life and performance • Use life cycle analysis to evaluate operating costs, asset depreciation, and expected performance to make informed maintenance decisions. • Use GPS technology to create a proactive approach to vehicle maintenance and reduce downtime.
Renew/Retire	• Renew/retire assets to minimize cost and maximize salvage recovery. • Use life cycle analysis to evaluate operating costs, asset depreciation, and expected performance to make informed replacement decisions. • Perform physical vehicle assessments to determine replacement or refurbish decisions.

5.7.2 Fleet and Equipment Inventory

The Fleet and Equipment asset class Inventory is found in **Table 5.7-3**.

Table 5.7-3: Fleet and Equipment Inventory

ASSET SUBCLASS	QUANTITY
Fleet	**864**
Light Duty Vehicles	654
Medium Duty Vehicles	210
Heavy Equipment	**338**
Backhoes	97
Trailers	174
Forklifts	30
Welders	32
Directional Drilling Equipment	5
Tools	**~5 ,000**

***** *Inventory count is current as of January 2018.*

5.7.3 Fleet and Equipment Condition and Strategy Overview

	ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Fleet	**Light Duty Vehicles**	5.3	Analysis indicates that average maintenance costs exceeds the market value of a light duty vehicle at an approximate age of six years or 180,000 km.	Aging light duty vehicles pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	Vehicle maintenance every 8,000 km (approximately every three months).	**Light Duty Vehicle Replacement Strategy**: This proactive program replaces approximately 50 light duty vehicles per year to maintain an average age of at or less than six years old over the 10-year span of this Asset Management Plan.
Fleet	**Medium Duty Vehicles**	7	Analysis indicates that average maintenance costs exceed the market value of a medium duty vehicle at approximately 10 years old.	Aging medium duty vehicles pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	Vehicle maintenance every 10,000 km or 500 engine hours (approximately every four months).	**Medium Duty Vehicle Replacement Strategy**: This proactive program replaces approximately 10 medium duty vehicles per year to maintain an average age of at or less than 10 years old over the span of this Asset Management Plan.
Heavy Equipment	**Backhoes**	10	Analysis indicates that average maintenance costs exceed the market value of heavy equipment at approximately 10 years old.	Aging heavy equipment assets pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	Equipment maintenance is conducted on a scheduled basis, ranging from three to six months, depending on the type of equipment.	**Heavy Equipment Replacement Program**: This proactive program is based on average historical spending (renewing or acquiring approximately two heavy equipment assets per year) and is driven by: • Proactively replacing assets based on a detailed physical condition assessment • Reactively acquiring net new equipment based on business needs.
Heavy Equipment	**Trailers**	10				
Heavy Equipment	**Forklifts**	12				
Heavy Equipment	**Welders**	9				
Heavy Equipment	**Directional Drilling Equipment**	7				
	Tools	N/A	The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations.	Aging, broken, or inadequate tools pose the following risks: *Safety Risk:* Employee and public safety *Financial Risk:* Increased maintenance costs and lower productivity *CSAT Risk:* Service and/or emergency response reliability	N/A	A reactive **Tools Replacement Program** is in place to address tools that are: • Showing signs of wear and tear, broken, and/or unrepairable • Stolen or lost • Declared obsolete by the manufacturer or supplier • No longer approved for use due to updated Engineering standards and practices • Needed and requested by EGD operating departments to perform their business functions (a tool requisition form is submitted)

5.7.4 Fleet

Light duty vehicles used by field employees range from mid-sized sedans, vans, and both small and heavy-duty pickup trucks. The age distribution and odometer reading of light duty vehicles are displayed in **Figure 5.7-2** to **Figure 5.7-4**.

MDVs range from mechanics' repair trucks to utility service trucks used by field crews. The age distribution and odometer reading of medium duty vehicles are displayed in **Figure 5.7-5** to **Figure 5.7-7**.

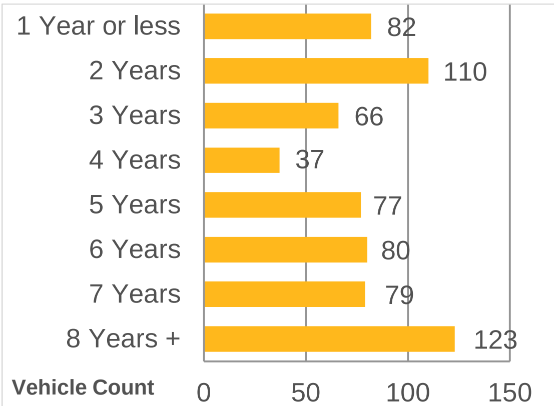


Figure 5.7-2: Light Duty Vehicle Age Distribution

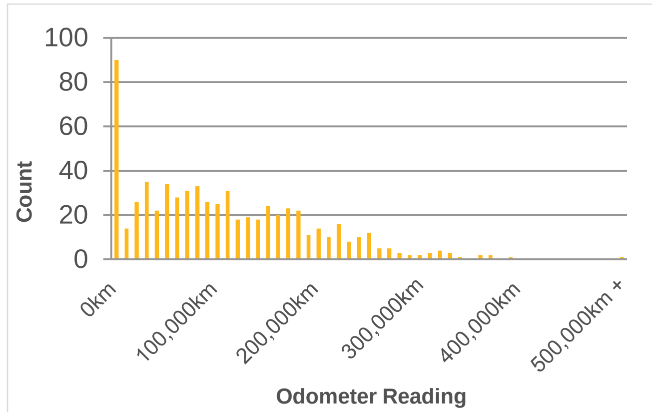


Figure 5.7-3: Light Duty Vehicle Odometer Reading

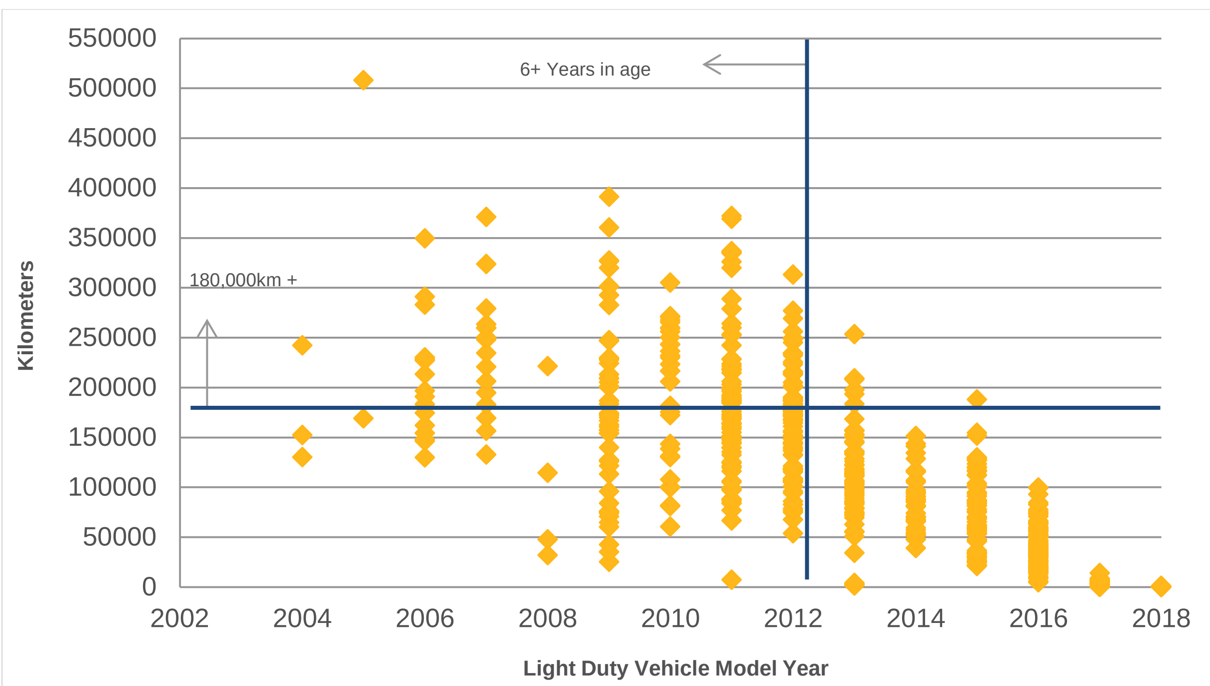
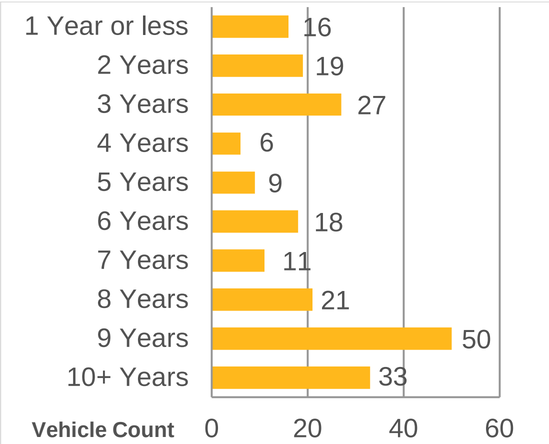


Figure 5.7-4: Light Duty Vehicle Age and Odometer Reading



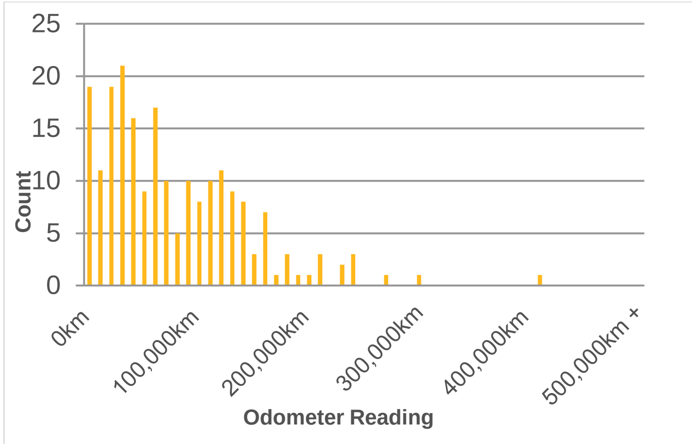


Figure 5.7-5: Medium Duty Vehicle Age Distribution

Figure 5.7-6: Medium Duty Vehicle Odometer Reading

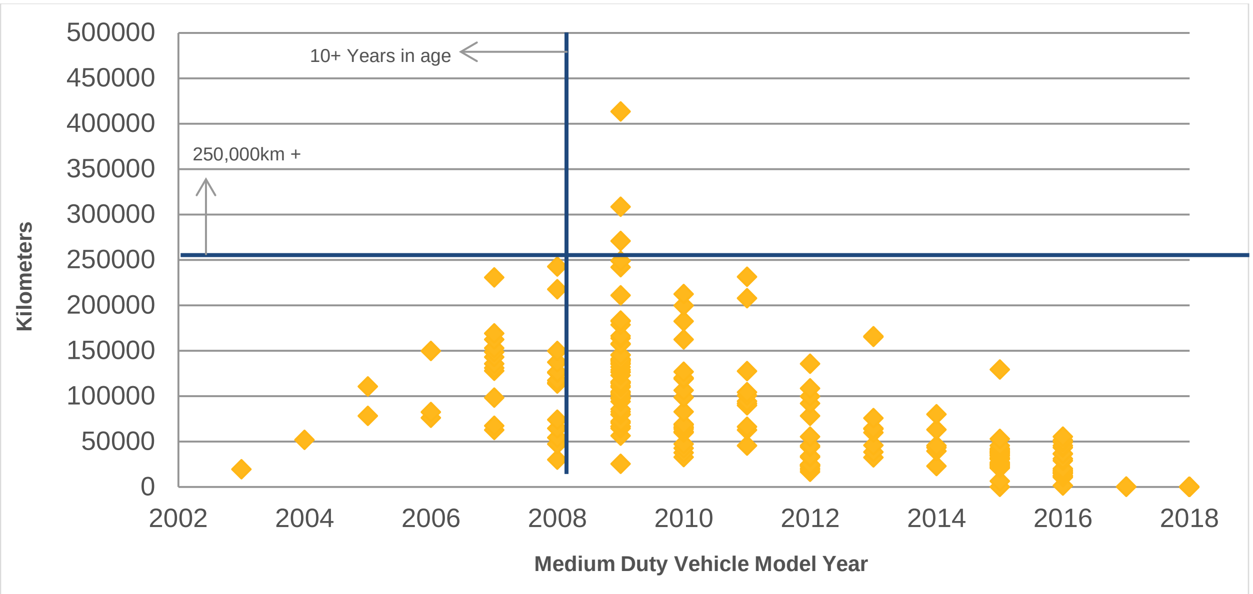


Figure 5.7-7: Medium Duty Vehicle Age and Odometer Reading

To understand how company vehicles are being utilized, fleet vehicles are equipped with Global Positioning System (GPS) tracking devices, managed by fleet management software (Geotab). The Geotab system also provides real-time vehicle diagnostics, giving EGD the ability to be proactive with fleet vehicle assessments and repairs. To reduce vehicle idling, APUs are installed in medium duty trucks, allowing work crews to use their power equipment without using the vehicle engine as a power source.

5.7.4.1 Condition Methodology

The Fleet department uses fleet management applications to record and analyze vehicle condition over their life cycle. Maintenance costs, fuel costs, mileage, age, and hour meter are recorded in FleetFocus software. Two other applications, Flagship Navigator and Flagship Fleet Replace, interface with FleetFocus to provide analytical reports on all fleet assets.

The Flagship Fleet Replace tool graphs the assets' cumulative maintenance cost against the asset class's average cost and the asset's depreciated value. An asset is assessed and considered for replacement once the average maintenance cost surpasses market value, unless there are conditions observed that justify shortening or prolonging asset life. If a vehicle exhibits higher maintenance costs than average, the vehicle is considered for earlier replacement. On the other hand, if a vehicle exhibits lower maintenance costs and assessed to be in good condition, it is considered for later replacement. This approach is guided by risk analysis, operating expense, and asset performance to sustain asset integrity.

Retaining vehicles too long increases operating and maintenance costs. Retiring vehicles too early results in the partial loss of their useful life, increasing capital and maintenance costs. The population's average point at which maintenance costs exceed the book value of the vehicle is used as a guide, it helps identify vehicles approaching end-of-life that require a detailed condition assessment to determine its fitness for service. The assessment consists of appraising vehicle attributes such as the engine and transmission condition, vehicle body condition, vehicle interior condition, etc.

5.7.4.2 Condition Findings

Figure 5.7-8 illustrates the average life cycle cost analysis for LDVs. The initial capital investment for a vehicle is approximately $30K (at age 0) and it is assumed to depreciate at 10.56% of its initial value, corresponding to a salvage value of zero at year 20. The guiding threshold is set at the point where the cumulative maintenance and repair costs (blue line) exceed depreciation (green line), as maintenance costs at this point will be higher than the vehicle market value. Based on analysis used to develop the appropriate threshold for detailed condition assessment and necessary replacement activities, the optimal guiding age threshold is approximately six years for LDVs.

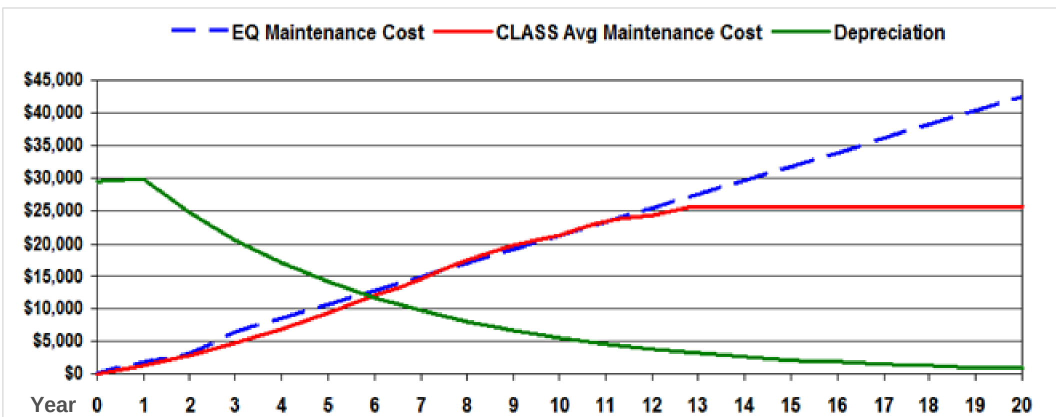


Figure 5.7-8: Maintenance and Depreciation Costs for Light Duty Vehicles

Similarly, **Figure 5.7-9** illustrates the average life cycle cost analysis for MDVs. The optimal guiding threshold for MDVs is at approximately nine years of age; however, due to lower mileage and the use of APUs which reduce engine wear and tear, the guiding age threshold is normally extended to approximately 10 years.

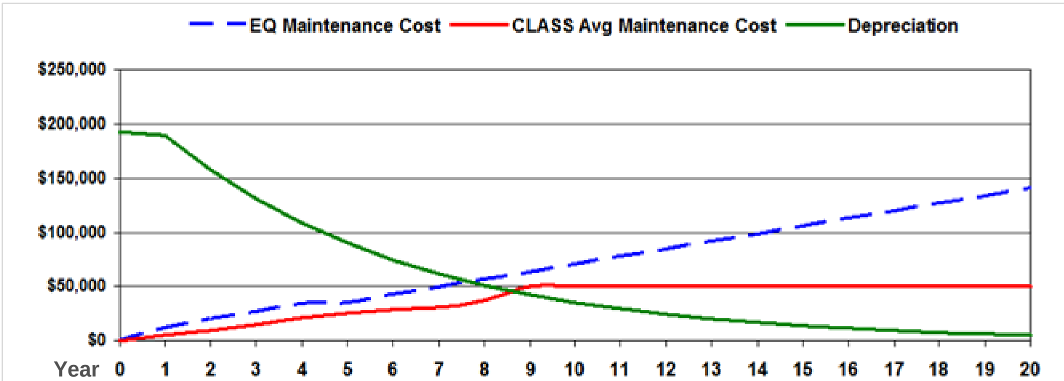


Figure 5.7-9: Maintenance and Depreciation Costs for Medium Duty Vehicles

Based on the age distribution as seen in **Figure 5.7-8** and **Figure 5.7-9**, 282 LDV vehicles (31%) are at or over six years old and 33 MDV vehicles (16%) are at or over 10 years old.

5.7.4.3 Risk and Opportunity

There are a number of consequences to EGD when LDVs and MDVs exceed their useful life:

- Aging asset condition, resulting in decreased safety and reliability
- Increased maintenance costs, which will eventually surpass the book value of the vehicle
- Increased downtime (vehicles are more frequently in the shop for maintenance), decreasing employee productivity
- Operational safety concerns potentially affecting employees, contractors and the public when vehicles fail

Based on the risk assessment analysis, fleet vehicles primarily pose a financial risk to EGD if they are not maintained or replaced as needed. Maintenance costs increase beyond the vehicle warranty and productivity is reduced due to increased downtime as a result of more frequent maintenance activities. On-road failure would also impact public safety and decrease productivity. Decreased productivity can affect the ability to serve our customers, potentially creating a risk to customer satisfaction.

5.7.4.4 Strategy

Light Duty Vehicle Replacement Strategy

The useful life threshold for LDVs is six years (equating to approximately 180,000 km assuming a typical LDV incurs 30,000 km per year). The threshold is used as a guide and helps build the 10 year replacement program for LDVs.

EGD's LDV replacement pace is approximately 50 vehicles per year, maintaining an average LDV population age at or below six years over a 10-year span, as seen in **Figure 5.7-10**. This approach is aligned with current industry best practices and EGD's historical approach.

Actual LDV unit replacement decision is based on detailed condition inspections. Using data from Flagship Navigator, vehicles scheduled for replacement inspections are prioritized based on a detailed cost-per-kilometer report and age - vehicles that have the highest operating expense are assessed and typically replaced first.

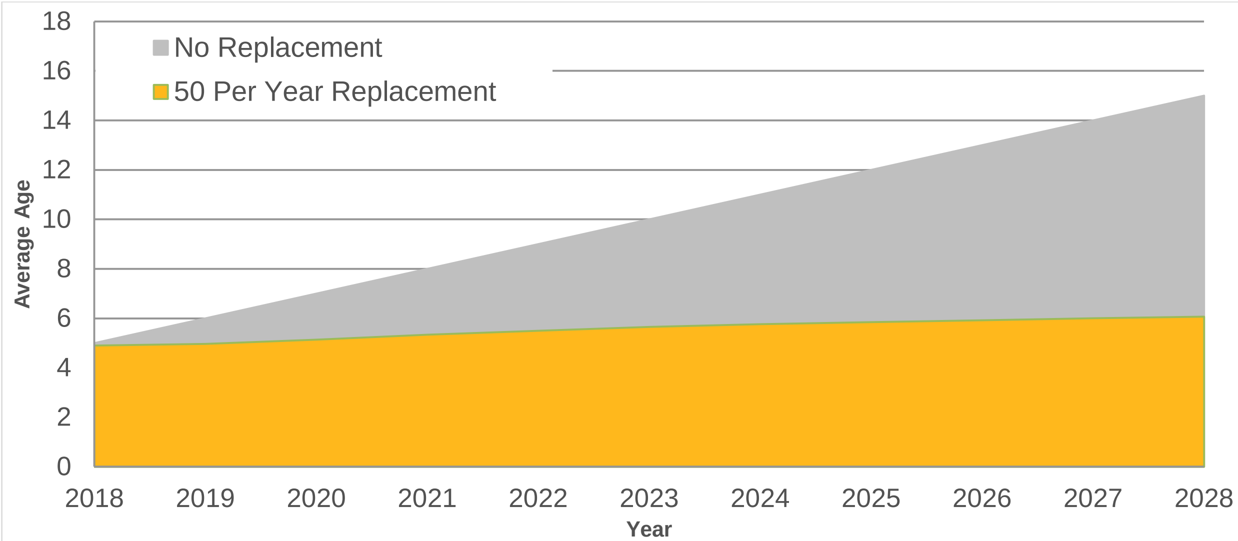


Figure 5.7-10: Average Age for Light Duty Vehicles (10 year span)

Medium Duty Vehicle Replacement Strategy

The useful life threshold for MDVs is approximately 10 years. The threshold is used as a guide and helps build the 10-year replacement program for MDVs.

Currently, EGD's MDV replacement pace is approximately 10 vehicles per year, maintaining an average MDV population age at or below 10 years over the 10-year span, as seen in **Figure 5.7-11**. This approach is aligned with current industry best practices and EGD's historical approach.

Actual MDV unit replacement decisions are based on detailed condition inspections. If repair costs to extend asset life is less than the asset book value, the vehicle could be refurbished instead of replaced, depending on its condition.

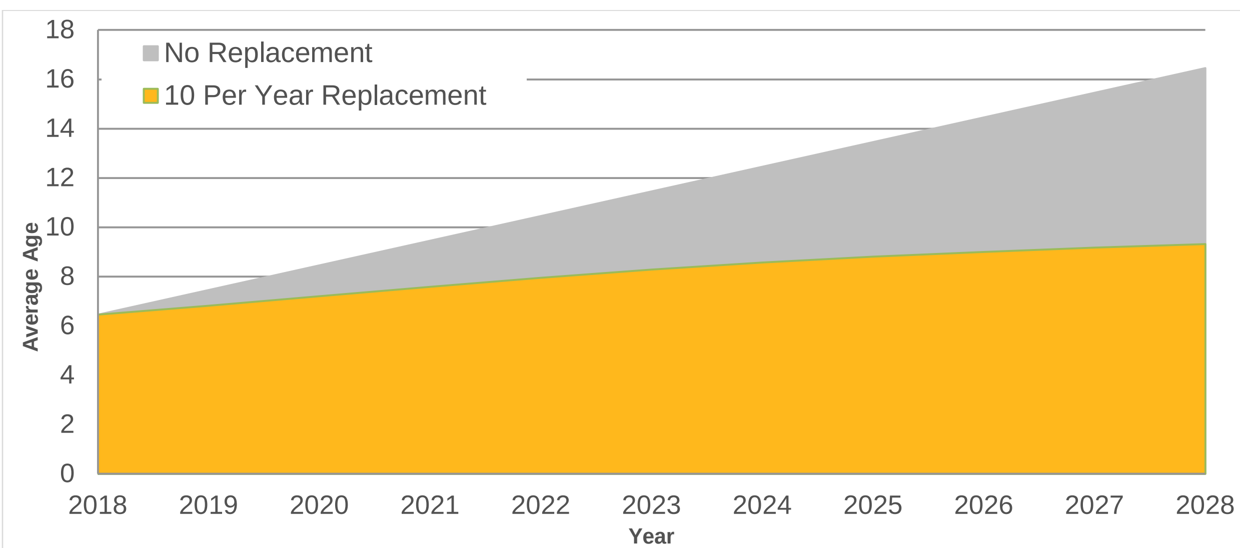


Figure 5.7-11: Average Age for Medium Duty Vehicles (10 year span)

5.7.5 Heavy Equipment

Heavy equipment is described as off-road building equipment; at EGD this asset subclass primarily consists of backhoes, trailers, compressors, forklifts, welding machines, and directional drilling equipment. These assets are grouped together due to similarities in condition methodology and approach.

5.7.5.1 Condition Methodology

As with fleet vehicles, the maintenance cost, fuel cost, and the mileage (or hour meter reading) for heavy equipment assets are tracked in FleetFocus. Flagship Navigator and Flagship Replace provide analytical reports that are used to guide decision making (i.e., to identify trending and to determine the average useful life threshold for the asset).

Retaining heavy equipment assets too long increases operating and maintenance costs. Retiring equipment too early results in the partial loss of their useful life, increasing capital and maintenance costs. The standard used to determine the optimal replacement point is when cumulative maintenance costs begin to exceed the market value of the asset.

In addition to Flagship reports, detailed condition assessments are conducted on heavy equipment assets every three to six months. This assessment includes a physical and visual evaluation of the equipment’s physical and functional condition, a comparison of hours of service, and an assessment of the maintenance history of the asset relative to its class. If the asset is assessed to be in good working condition, it is kept in service and refurbished to extend its useful life. If the asset is assessed to be in poor condition and not fit for continued service, it is replaced.

5.7.5.2 Condition Findings

Based on Flagship program reporting, industry standards, and asset assessment trends, the typical average useful life threshold for heavy equipment is at approximately 10 years of age (or approximately 7,000 service hours). This threshold is used as a guide for further detailed inspections. The condition of these units is thoroughly assessed when they reach their useful life threshold to make an informed decision to replace or refurbish the asset for continued service.

Heavy equipment condition findings are summarized below:

Backhoes

Backhoes are heavy mechanical equipment assets used during trenching and excavation activities. These assets are individually maintained every three months and the unit’s physical and functional condition and maintenance history are evaluated.

The backhoe asset subclass consists of an aging population - the age distribution indicates 50 units (52% of the population) are at or over 10 years old (see **Figure 5.7-12**). Based on the maintenance cost summary report, five backhoes are currently operating higher than the class average, qualifying them for further condition assessments to determine their replacement priority within the 10-year span.

Figure 5.7-12: Backhoe Age Distribution

Trailers

A number of different trailer types are used at EGD, including float trailers, pipe trailers, shoring trailers, workspace trailers and small yard trailers. Trailers are used for different types of jobs – for example, float trailers are used to transport backhoes from company yards to job sites and workspace trailers are used to set up off-site work stations.

Trailer maintenance is scheduled every six months. These assets are also inspected annually (mandated by the Ministry of Transportation) to receive a valid certification for use.

The current age distribution of trailers, as seen in **Figure 5.7-13** indicates 64 units (or 37% of the population) are at or over 10 years old.

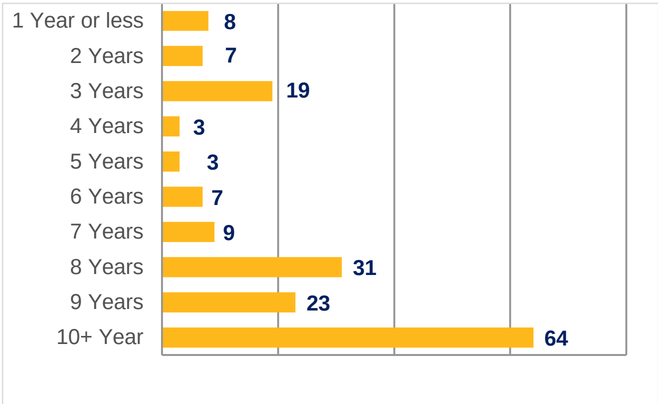


Figure 5.7-13: Trailer Age Distribution

Trailers are either replaced, refurbished or maintained for service as required. In most cases, a trailer can be refurbished to extend its useful life at a much lower cost than replacement. Refurbishment activities often include the installation of new wheels and brakes, as well as sandblasting and re-painting. Based on current assessments, no trailers are in need of replacement.

Forklifts

Forklifts are used in EGD's warehouses and meter shop to load, offload, and move material. Forklifts are maintained on a six-month cycle and have a mandatory annual lift inspection requirement for certification.

The age distribution of forklifts (**Figure 5.7-14**) indicates 10 units (33% of the population) are at or over 10 years old. Based on the maintenance cost summary report, 10 forklifts are operating higher than the class average. However, due to their very low meter run-time, these units will be closely monitored and maintained for use at this time.

Based on the results of the individual condition assessments, forklifts are either replaced, refurbished or maintained for service as required.

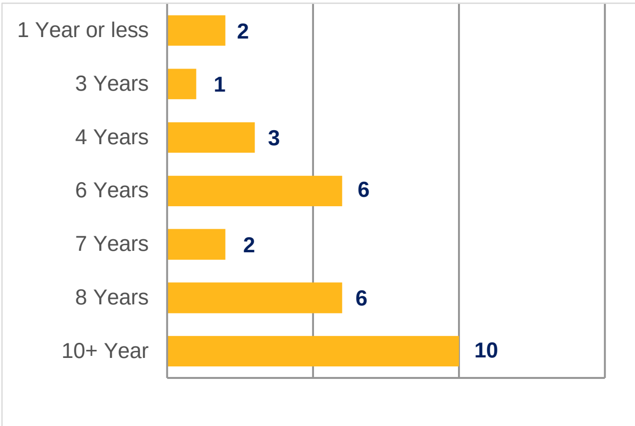


Figure 5.7-14: Forklift Age Distribution

Welding Machines

Welding machines are used to perform installation, repairs and maintenance of natural gas mains.

Welding machines are maintained on a six-month cycle. The age distribution of the welding machine asset population indicates 15 units (45% of the population) are at or over 10 years old (**Figure 5.7-15**). In addition, three welding machines are operating higher than the class average, qualifying them for further condition assessment to determine the priority of replacement within the 10-year span.

Based on the results of the individual condition assessments, welding equipment is either replaced, refurbished or maintained for service as required.

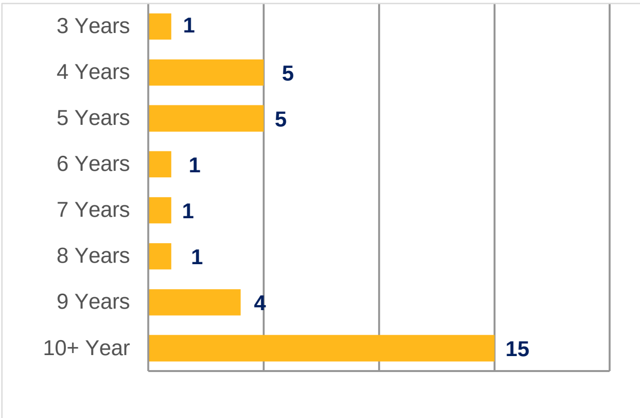


Figure 5.7-15: Welding Machine Age Distribution

Directional Drilling Equipment

Directional drills are used to perform trenchless installation of gas mains and services. The directional drilling equipment is maintained on a four-month maintenance cycle.

Based on the results of the individual condition assessments, directional drilling equipment is either replaced, refurbished or maintained for service as required.

The age distribution of the directional drilling equipment (**Figure 5.7-16**) shows five units ranging from one to nine years old. One unit is nearing the 10-year useful life threshold and is operating higher than the class average, qualifying it for further condition assessment to determine its replacement priority within the 10-year span.

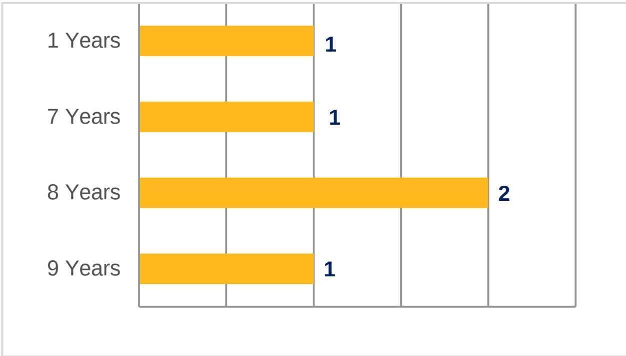


Figure 5.7-16: Directional Drilling Equipment Age Distribution

5.7.5.3 Risk and Opportunity

There are a number of consequences to EGD if the heavy equipment assets exceed their useful life threshold and are not replaced when detailed physical assessments indicate to do so:

- Aging equipment (at or surpassing its useful life threshold) is at a higher likelihood of failure.
- Equipment failures pose operational safety concerns to employees, contractors and the public.
- Equipment failures can lead to increased maintenance costs for required repairs.
- Increased downtime due to repairs can reduce overall productivity and can affect EGD's ability to serve its customers.
- Equipment that operates beyond its warranty see an additional increase in maintenance costs (i.e., the cost of repairing certain equipment components that are out of warranty)

Based on the risk assessment analysis, heavy equipment primarily poses a financial risk to EGD if they are not maintained or replaced as needed.

5.7.5.4 Strategy

EGD has an annual heavy equipment program based on average historical spending and is driven by proactively replacing assets based on detailed physical condition assessment and reactively acquiring new equipment based on business needs. Depending on evaluation results, there could be a decision to refurbish the asset instead of replacement.

Typically, the program replaces two pieces of heavy equipment each year (primarily backhoes/forklifts), to pace and prioritize the program spend uniformly over the 10-year span. This strategy, combined with a strong maintenance program, sustains and improves the safe and reliable operation of heavy equipment assets and has demonstrated its effectiveness by maintaining a zero incident safety record.

5.7.6 Tools

EGD uses a wide variety of tools, including electric air movers, drills, concrete saws, clay spades, gas surveyors, personal gas monitors, pipe locators, pipe squeeze-off tools, shoring boxes, torpedoes, grease guns, etc. In total, there are over 5,000 tools currently in use.

Due to the variety of tools and equipment, several inspection and calibration frequencies are in place. For example, combustible gas detectors require weekly calibration and inspection, plastic pipe squeeze-off tools require annual inspection, and electric water pumps do not have a formal inspection program. The general condition and functionality of tools are assessed by the operator prior to use and during scheduled inspections and calibrations. Deficiencies identified are reported to the Fleet & Equipment department where an assessment of the repair and replacement costs is completed to determine the appropriate course of action.

5.7.6.1 Risk and Opportunity

Not maintaining EGD's tool population when needed presents both a safety risk to the employee and to customers during operation. In addition, productivity will decline due to increased downtime as a result of using inadequate tools, posing both a financial risk to EGD as well as impacting our reputation and customer satisfaction.

5.7.6.2 Strategy

The strategy for tools is to establish an annual replacement program based on average historical spend. The program is reactive in nature and driven by replacing/acquiring tools that are:

- Signs of wear and tear, or are broken and not repairable
- Stolen or lost
- Deemed obsolete by the manufacturer
- No longer approved for use due to evolving Engineering standards and practices
- Required by EGD Operations departments for business function

Tools and equipment deemed obsolete and/or are no longer approved for use are removed from service, decommissioned, and approved replacement assets are acquired.

5.7.7 Fleet & Equipment Capital Expenditure Summary

The summary of projects and programs under the Fleet and Equipment asset class accounts to $67M from 2019 to 2028, as summarized in **Table 5.7-4**. The Fleet & Equipment capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.7-4: Fleet & Equipment Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-year Forecast
Light & Medium Duty Vehicles	5,069	4,903	5,051	4,652	4,871	4,586	4,495	4,636	4,636	4,636	47,533
NG Conversion Kits for New Fleet Vehicles	400	408	416	424	432	586	535	546	557	-	4,304
Heavy Equipment	500	500	500	500	454	741	622	636	636	636	5,725
Tools	800	800	800	1,000	1,000	1,000	1,000	1,000	1,000	1,000	9,400
Fleet Assets Total	**6,768**	**6,610**	**6,767**	**6,576**	**6,757**	**6,913**	**6,652**	**6,818**	**6,829**	**6,272**	**66,962**

5.8 TECHNOLOGY AND INFORMATION SERVICES (TIS)

5.8.1 Technology and Information Services Objectives

The Technology Information Services (TIS) asset class includes the Hardware, Software, and Communications subclasses (**Figure 5.8-1**). Under the Hardware asset subclass there are two types of assets: Laptops/Desktops and Desktop Sustainment Equipment. Desktop sustainment equipment includes the additional Information Technology (IT) components that equip the end user, such as keyboards, telephone headsets, computer monitors, audio/visual equipment, telephony, printers, scanners, and ergonomic equipment.

Software assets consist of packaged applications (purchased from and generally supported by a vendor), developed applications (custom built in-house), and application infrastructure software (foundational infrastructure software and tools for applications). Software assets often consist of a hardware component.

Communications assets include mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).

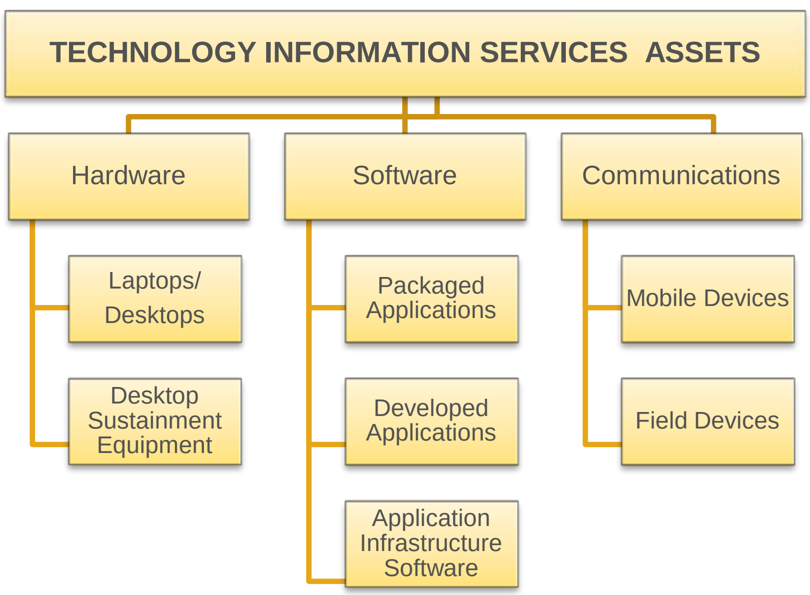


Figure 5.8-1: Technology Information Services (TIS) Asset Classification

The overall goal of the TIS asset class is to meet EGD's IT needs that have been established in response to asset, process, and system objectives and concerns. The response to these needs and the decision to undertake a solution is guided by the following IT asset class objectives listed in **Table 5.8-1**.

Table 5.8-1: TIS Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
Reliability	Maintain the ability of the asset to perform its required function over its useful life.	• Number of application/system outages • Number of hardware and communication repairs
Security	Ensure controls and checks are in place for applications/software that protects the asset against threats and vulnerabilities.	• Number of vulnerabilities and security-related incidents • Adherence to security policies and scorecard objectives
Availability	Ensure that hardware, devices and/or applications/software are readily available for use when required and will work as intended.	• Overall system and application availability metric
Supportability	Maintain the ability of support/service staff to install, configure, and monitor assets, identify exceptions and faults, isolate defects/issues preventing the asset from functioning as expected, and provide maintenance services.	• Overall system and application availability metric • Number of hardware incidents and replacements required • Change compliance metric
Maintainability	Continually ensure that assets are maintainable to isolate and correct defects, prevent unexpected breakdowns, maximize their useful life, meet new business requirements, and simplified future maintenance procedures.	• Number of change and enhancement requests • Incident response time and resolution met
Continuous Improvement	Continuously evolve the understanding of condition and risk for TIS assets and use cost, risk, and performance information to drive asset-related decisions.	• Risk Mitigated and LRROI • QRA completion %

To achieve these objectives, asset investment decisions are governed by the Life Cycle Management policies in **Table 5.8-2.**

Table 5.8-2: Life Cycle Management for TIS Assets

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Evaluate business requirements to ensure IT solutions are justified. • Procure/Design/Build IT solutions to satisfy business requirements and meet/exceed applicable codes and policies.
Utilize	• Commission IT assets for use by employees and contractors for safe and reliable use. • Monitor the use of assets to understand utilization and justify future life cycle decisions. • Provide business and employees with support and service for optimal use of IT assets and business solutions.
Maintain	• Maintain the working condition of IT assets to ensure efficient, effective, and sustained operations. • Minimize unplanned outages and downtime by maintaining the integrity of IT assets.
Renew/Retire	• Dispose of assets in a manner that minimizes cost, maximizes salvage recovery, and destroys records according to EGD's Record Management Policy. • Renew or replace IT assets to: - Meet the changing needs of the business - Increase performance - Realize efficiencies - Address obsolescence • Evaluate the condition and performance of IT assets to justify renewal decisions.

5.8.2 Technology and Information Services Inventory

The TIS asset class inventory is presented in **Table 5.8-3.**

Table 5.8-3: TIS Asset Class Inventory

ASSET SUBCLASS	QUANTITY
Hardware	**2,914**
Laptops and Desktops	2,914
Desktop Sustainment Equipment	N/A*
Software	**121**
Packaged Applications	43
Developed Applications	55
Application Infrastructure Software	23
Communications	**3,374**
Mobile Phones	1,980
Field Devices	1,394

**The inventory count for Desktop Sustainment Equipment assets is not recorded.*

5.8.3 Technology and Information Services Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Laptops and Desktops	4	Laptops and desktops tend to experience performance issues and failures in their fourth year of operation.	Aging laptops and desktop assets primarily pose a financial risk to EGD as non-performing assets result in a reduction in productivity and an increase in maintenance costs.	Reactive maintenance as required through service requests.	**Laptop/Desktop Renewal Strategy**: EGD's strategy is to replace laptops and desktops every four years. For the majority of their life (three years), these assets are under warranty. This strategy allows for a short extended use of the asset past warranty expiration (one additional year) prior to replacement.
Desktop Sustainment	N/A	The condition and health of desktop sustainment equipment is not proactively monitored.	Aging and/or inadequate desktop sustainment equipment pose the following risks to EGD: *Safety Risk* : Compromises the health and safety of employees who require specific equipment for ergonomic purposes *Financial Risk*: Reduction in productivity	Reactive maintenance as required through service requests.	**Desktop Sustainment Equipment Strategy**: Desktop sustainment equipment is provided on an as-needed basis. The replacement of desktop sustainment equipment is based on the following circumstances: • Equipment is damaged, broken, or malfunctioning. • Equipment is required based on employee ergonomic assessments. • Equipment is required for new employee and contractor hires.
Software: Packaged & Developed Applications	10	A number of packaged and developed applications require updates to: • Meet business requirements and/or maintain the ability to enhance and support existing applications • Meet vendor support requirements for hardware • Meet vendor support software life cycles (for packaged applications) • Improve the quality of customer experiences (informed by customer engagement results)	There are a number of consequences to EGD if its applications are not maintained, renewed or enhanced when needed. These risks include: *Safety Risk:* This risk increases if systems providing operational functionality for emergency calls encounter issues and are unavailable. *Financial Risk:* • Inability to meet business needs and requirements, reducing overall productivity • Decreased productivity due to extended application and system outages • Outages, application downtime, and potential security breaches result in loss of revenue • Inability to meet financial and reporting compliance requirements • Increased maintenance costs due to reactively addressing required software and hardware repairs *CSAT Risk:* • Cybersecurity exposure due to the inability to apply security patches to end-of-support software, which could also affect EGD's reputation if any breaches occur • Customer satisfaction could suffer if client-facing systems are unavailable The following opportunities were identified for packaged, developed, and infrastructure applications: *Financial Opportunity:* Significant operating and maintenance cost savings opportunities associated with customer experience enhancements *CSAT Opportunity*: Improved self-service customer experiences due to enhanced functionality associated with software updates	Maintenance releases and software bug fixes are rolled out regularly as a means of reactively maintaining the performance of packaged and developed applications.	**Proactive Software/Hardware Renewal Strategy**: EGD has a proactive replacement strategy to keep software and hardware current and supported. The specific replacement strategy is dependent on changing business requirements or due to an application solution becoming unsupported by its vendor. The following applications require upgrade/renewal over the next three years: • Enbridge Meter and Reporting (EnMar) is being replaced by a solution using Customer Information System (CIS) and Work and Asset Management Solution (WAMS). • Demand Side Management (DSM) is being replaced by a packaged solution. • The EGD extranet is being replaced by a packaged solution. • The Meter Reading System (MVRS) is being partially replaced by a custom meter reading application in 2018, and some existing components that must remain on MVRS are being upgraded. • The Land Management system (LAMPS) is being replaced. • The Datapak application will be replaced. • The Business Development Datamart (BDDM) is to be migrated to SAP Business Warehouse (SAP BW). • The iViewer application will be replaced by a more robust records storage repository. **Customer Experience Strategy**: EGD has a Customer Experience Transformation project, consisting of initiatives that span multiple asset subclasses within the TIS asset class. This two year project proactively transforms the way we do business with our customers and to improve customer interactions.
Software: Infrastructure Applications	12	There are a number of application infrastructure assets that require updates to: • Meet vendor support software life cycles • Support key foundational software required for in-use/predicted applications.		Maintenance is reactive - performance issues or software bugs are addressed as they are identified.	**Application Infrastructure Renewal Strategy**: A proactive replacement/refresh strategy is in place, driven by forecasted changes to existing software products and business requirements.

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Mobile Devices	3	The condition of mobile devices is not proactively monitored.	Not maintaining mobile devices primarily results in a safety risk for EGD because the inability to respond to emergency field situations and to resolve off-hours on-call situations will potentially be compromised, jeopardizing the reliable and safe operations of TIS systems and applications.	Mobile devices are maintained internally to address performance issues. Damaged devices are repaired on an as-needed basis within the three-year replacement window.	**Mobile Device Renewal Strategy**: EGD's replacement strategy is aligned with industry best practices with replacements planned for every two to three years (aligned with smartphone manufacturers' release cycles and typical data plan contracts).
Field Devices	4	The condition of field devices is not proactively monitored. Due to exposure to tough working conditions, field devices experience significant wear and tear. (Breakage and performance issues generally occur in their fourth year of use).	Not maintaining field devices primarily results in financial risk for EGD as it will potentially contribute to productivity loss. The efficiency of field work will be compromised due to devices being unavailable. Travel time will increase between the office and job sites.	Maintenance repairs and replacements are performed as needed through service requests.	**Field Device Renewal Strategy**: Most EGD field devices have a four-year proactive replacement strategy driven by industry best practice. Some assets, such as truck modems, are reactively replaced as needed.

5.8.4 Laptops and Desktops

This TIS asset subclass includes 2,914 laptops and desktops. The majority of employees and contractors rely heavily on the day-to-day performance of their laptops and desktops to perform daily tasks and to access company communications, applications, and resources on EGD’s networks and systems.

Laptops and desktops are under manufacturer warranty for three years.

5.8.4.1 Condition Methodology

The condition of laptops and desktops is not proactively monitored. If these assets experience failures or signs of operating issues, a ServiceNow request for support and resolution is logged. All laptops and desktops are labelled with a unique asset tag number to identify the asset for tracking purposes. The ServiceNow request is mapped to the user’s unique asset tag number, which ensures the necessary remediation work is completed on the appropriate asset.

5.8.4.2 Condition Findings

Laptops and desktops tend to experience performance issues and failures in their fourth year of operation, a year after their warranty expires. Currently, this constitutes approximately 30% of the laptop and desktops in operation. Laptop failures can occur for a variety of reasons, including complete hard drive failures, processor board failures, memory failures, and significantly degraded performance.

In 2016, 50% of laptops and desktops were replaced in a major replacement initiative, resulting in almost 40% reduction in total logged incidents by users, demonstrating that replacing these assets before problems start to occur reduces the number of incidents reported.

5.8.4.3 Risk and Opportunity

There are a number of consequences if these assets are not replaced soon after warranty expiry:

- Replacement parts for existing hardware become obsolete, resulting in an asset that is more expensive to repair.
- Existing hardware is not compatible with newer operating systems and applications, resulting in an asset with reduced functionality.
- Maintenance costs can become excessive after warranty expiry.
- There is an overall reduction in productivity due to aging assets.

5.8.4.4 Strategy

EGD’s strategy is to replace laptops and desktops every four years. Industry best practice suggests replacing laptops and desktops every three years, in line with its warranty (also three years). EGD’s strategy allows for one additional year past warranty expiration prior to replacement, reducing the overall capital cost of the laptop refresh cycle.

Defective or poorly performing laptops that are out of warranty are repaired if the problem is quickly determined and can be done cost effectively. Otherwise, the device is replaced. The impact of repairing an out-of-warranty device includes productivity loss to the end user, technician repair time, and the cost of unbudgeted parts for repair. As more and more out-of-warranty devices fail over time, the current replacement strategy is the most logical action.

The four-year replacement policy for laptops and desktops has been in place for the last 15 years and has proven to be sufficient and manageable from a resourcing perspective.

5.8.5 Desktop Sustainment Equipment

Desktop sustainment assets include all TIS hardware equipment required for business operations. Audio/visual equipment, printers, monitors, keyboards, mice, privacy screens, and headsets are some examples of desktop sustainment equipment.

5.8.5.1 Condition Methodology

The condition of desktop sustainment equipment is evaluated on the following:

- New hire onboarding information
- Hardware incident requests
- Feedback and requests from ergonomic specialists and business users

5.8.5.2 Condition Findings

Annually, there are approximately:

- 370-400 ergonomic-related requests requiring ergonomic equipment
- 320-370 onboarding requests requiring desktop sustainment equipment to support new employees/contractors
- 470 hardware incidents

5.8.5.3 Risk and Opportunity

A number of consequences were identified if these assets are not provided or replaced when required:

- The health and safety of employees who require specific equipment for ergonomic purposes may be compromised, which could result in potential discomfort or pain.
- A potential loss of productivity for employees that suffer ergonomic-related injuries due to the lack of appropriate equipment.
- An overall reduction in productivity due to the lack of desktop sustainment equipment for new hires.

5.8.5.4 Strategy

Desktop sustainment equipment is provided on an as-needed, reactive basis. Desktop sustainment equipment is issued based on the following:

- Equipment is damaged, broken or malfunctioning.
- Equipment is required based on an ergonomic assessment.
- Equipment is required for new employee and contractor hires.

EGD uses historical spend to project the capital requirements for the replacement of desktop sustainment equipment.

5.8.6 Packaged and Developed Applications

Packaged applications are solutions purchased from and primarily supported by a vendor; support includes software version upgrades. Software upgrades are required for the application to stay current and supported. For some solutions, EGD provides functionality and enhancement requests and the vendor provides additional software releases to address these requests.

Developed applications are custom-built solutions by EGD to meet business requirements. This generally occurs when no packaged solutions are available to support business requirements.

5.8.6.1 Condition Methodology

The condition of packaged and developed applications is evaluated on the following:

- Ability to meet business requirements
- Hardware to meet vendor support requirements
- Software to meet vendor support life cycle (for packaged applications)
- Ability to enhance and support other existing applications
- Understanding and improving our customers' experiences

5.8.6.2 Condition Findings

Table 5.8-4 summarizes the packaged applications used at EGD and outlines their current state and condition.

Table 5.8-4: Application State – Packaged Applications

APPLICATION	APPLICATION OVERVIEW	AGE (YRS)	APPLICATION STATE
Asset Investment Planning (PP-AMP)	Asset management tool	3	Hardware is currently under warranty. Software was upgraded in 2018.
Customer Information System (CIS)	Customer care and billing application	9	Hardware is currently out of warranty. Software will be out of support by 2020.
DSM	Demand-side management data analysis reporting and tracking system	11	No on-premises hardware upgrades required. Application replacement is underway in 2018.
EGD Extranet	EGD external website with self-service capabilities	1	Hardware was replaced in 2017/2018. Rewrite and foundational software upgrade occurred in 2017/2018.
Enbridge Meter and Reporting (Enmar)	Meter asset management system	14	No additional hardware component required (existing applications will be utilized). Software platform will be out of support from vendor by 2019.
Engineering Quality Management (EQMT)	Engineering application for quality assurance inspections records	6	The solution is on shared hardware, will be out of warranty in 2020. Software is current and supported.
Geographic Information System (eGIS)	Application for developing geographic views of asset data	7	Hardware will be out of warranty in 2019. Software was upgraded in 2018.
Leak Survey Management System (LSMS)	Application for leak survey inspection-related work	5	The solution is on shared hardware, will be out of warranty in 2020. Software is current and supported.
Meter Reading System (MVRS)	Application for storing manually-gathered meter readings and meter maintenance information.	8	The solution is on shared hardware, will be out of warranty in 2021. The current software version is unsupported by the vendor.

APPLICATION	APPLICATION OVERVIEW	AGE (YRS)	APPLICATION STATE
Powerspring (formerly Metretek)	Application providing automated meter readings for large volume customers	1	Hardware and software were upgraded to current and supported versions in 2017.
Teldig	Locate-tracking application completed by locates service providers through Ontario One Call	7	Hardware will be out of warranty in 2019. Software will be out of currency in 2019
Work and Asset Management (WAMS)	Application to manage work and assets	3	Hardware will be out of warranty in 2019. Software was upgraded to a current version in 2018 for both Maximo and Click components.

Table 5.8-5 summarizes the developed applications used at EGD and outlines their current state and condition.

Table 5.8-5: Application State – Developed Applications

APPLICATION	APPLICATION OVERVIEW	AVG.AGE (YRS)	APPLICATION STATE
Business Development Data Mart (BDDM)	Data Mart of customer and consumption data for Business Development	8	Hardware is currently under warranty. Software is current and supported.
Capital and O&M Management (COMMS)	Application for managing EGD capital projects	7	Hardware is currently under warranty. Software was upgraded in 2018.
Customer Connections Worksuite	Application for managing Customer Connections information	5	Hardware is currently under warranty. Software is current and supported.
Datapak	Application to locate asset information (used by field workers)	17	Software was upgraded in 2017. Changing business requirements are driving to a replacement solution in 2019/2020.
Energy Cost Reporting (EnCore)	Application to develop cost models for energy supply	6	Hardware is currently under warranty. Software is current and supported.
EnTrac	Management software for large volume and direct purchase contracts	14	Hardware will be out of warranty in 2019. Software is current and supported.
Finance Business Analysis (FBA)	Data warehouse for reconciliation of customer consumption	3	Hardware is currently under warranty. Software is current and supported.
iViewer	Image repository for as-laid drawings, scans of service tickets, and field notes.	7	Hardware is currently under warranty. Software was upgraded in 2018. Long-term replacement planning is currently underway.

APPLICATION	APPLICATION OVERVIEW	AVG.AGE (YRS)	APPLICATION STATE
Land Management (rowAMPS)	Application managing land/property and municipal taxation work of the Land Services Department.	1	Hardware is currently under warranty. Software was replaced in 2017.
Revenue Analysis & Volume Estimation (RAVE)	Application for volumetric analysis, estimation and budgeting.	13	Hardware is currently under warranty. Software is current and supported.
Unbundled Rate Compliance (URICA)	Application for customers to request and track unbundled services as per Natural Gas Electricity Interface Review (NGEIR) direction.	11	Hardware will be out of warranty in 2019. Software is current and supported.

Customer Experience

EGD's technology landscape employs a number of applications to service 2.1 million customers. The SAP Customer Information System (CIS) is the core application that drives all aspects of customer service including billing, account management and collections. CIS is also integrated with a number of other systems across multiple channels and services, including WAMS, to enable field access to customer information, and Sitecore (web content management platform running the EGD Extranet) to enable online self-service.

Customers are a critical stakeholder and their experience is of utmost importance to EGD. EGD engaged its customers to understand their customer service experiences - the results showed that customers felt that EGD had a low sense of urgency to provide quality customer service. Some examples of the responses were:

- "It's a lot of paper! You're telling me you don't want to send me paper, but I still get a lot of paper."
- "Mostly I keep pressing '0' to get to the right person."
- "They just don't care. Yes, they provide a service and my home is safe, but they just don't care."

EGD's customer vision is to provide seamless customer service experiences that demonstrate a level of caring and understanding that meets or exceeds customers' expectations every time. The following elements have been identified to improve the quality of customer experiences:

- Enhanced online experience, including EGD Extranet redesign
- Web and social chat capabilities
- Personalized Interactive Voice Response (IVR) telephony functionality
- Optimization of core customer service and billing, including exception handling and real time payments
- Implementation of outbound communications and campaigns
- Optimization of field activities, including meter reading, meter management, and appointment scheduling
- Call volume reduction and improved self-service to drive customers to use online resources
- Work automation/elimination through the redesign of key processes and transactions
- eBill adoption to improve online experience and drive adoption of electronic billing to 50% of the customer base

5.8.6.3 Risk and Opportunity

A number of consequences were identified if packaged or developed applications are not maintained or renewed when needed:

- Inability to meet business needs and requirements, reducing overall productivity
- Cybersecurity exposure due to the inability to apply security patches to End-of-Support software, potentially leading to reputational impact if any breaches occur
- Decreased productivity due to extended application and system outages
- Increased safety risk if systems providing functionality for emergency calls are unavailable
- Financial risk due to outages and potential security breaches, resulting in loss of revenue
- Inability to meet financial and reporting compliance requirements

- Decreased customer satisfaction due to unavailable client-facing systems
- Increased maintenance costs due to reactively addressing required software and hardware repairs

In addition, acting on the identified areas for customer experience improvement will provide EGD with the opportunity to improve customer satisfaction and financial performance by achieving the following:

- Improved self-service customer experience
- Greater billing accuracy and streamlined payment processing
- Greater account information accuracy (account information is up to date and customers can submit payment and receive confirmation of receipt in the same day)
- Fewer billing exceptions, collection activities, and in-bound calls
- Significant operational benefits and $13M annual O&M savings, including:
    - Lower average handling time
    - Increased leads for DSM programs
    - Business process improvements
    - Technology currency
    - Call volume reduction
    - Work automation
    - Increased e-Bill adoption
    - Automated Customer Connections process

5.8.6.4 Strategy

Packaged and Developed Application Renewal Strategy

The replacement strategy for packaged applications is driven by vendor release schedules specific to each application and changes in business requirements. A replacement and/or upgrade can also occur due to the vendor discontinuing software support or application enhancements.

The replacement strategy for developed applications is driven by forecasted requirements for the business. Maintenance releases and software bug fixes are rolled out regularly to reactively maintain the performance of the application. Major enhancements and renewals are implemented for projected new or changing business requirements.

Applications are replaced when business requirements change or when a vendor ceases support for the application. Four key applications are being replaced in 2018 and 2019, with another three applications identified for replacement in 2020 and 2021. From 2022 onwards, the average historical spend profile is used to forecast future TIS spend, as needs are identified and scope is refined. The following is a breakdown of the applications requiring upgrade/renewal over the next four years:

- EnMar is being replaced by a solution using CIS and WAMS.
- DSM is being replaced by a packaged solution.
- The EGD Extranet is being replaced by a packaged solution.
- MVRS is being partially replaced by a custom meter reading application in 2018. Some existing components that must remain on MVRS are being upgraded.
- LAMPS is being replaced by rowAMPS.
- BDDM will be migrated to SAP Business Warehouse.
- The iViewer application will be replaced by a more robust records storage repository.

Customer Information System (CIS)

CIS is the next major application scheduled for upgrade. CIS hardware consists of two major components:

- **CIS Base System Hardware** is comprised of approximately 32 servers and over 60 terabytes of disk storage required to run the CIS SAP solution and to store CIS data.

- **CIS Archiving Hardware** is the hardware platform for the CIS archiving solution. CIS data is stored and retrieved in the archiving solution to free up space in the database and optimize batch processing performance, allowing data to be available in read-only mode for customer queries.

SAP is moving their software platform to run on its HANA proprietary technology, requiring specialized system hardware and storage appliances. If current the CIS hardware is not replaced, it will be unsupported by 2020.

Customer Experience Transformation Strategy

EGD's Customer Experience Transformation project consists of initiatives that span multiple TIS asset subclasses. This two year project proactively transforms the way EGD does business with its customers to make customer interactions easier. The project will also provide EGD with O&M savings of approximately $13M annually.

Year 1

- Implement mobile meter reading and improve late stage collection process.
- Rewrite extranet (Web 1.0 & 2.0): Implement SAP Multi-Channel Foundation (MCF) integration, re-platform the underlying technology, implement a concierge experience online, and implement interactive billing.
- Deploy Web chat and live chat proof of concept and pilot.
- Implement a BDex exception management solution and required process changes.
- Leverage analytics and artificial intelligence to improve bill estimation.

Year 2

- Extend SAP MCF integration.
- Enhance the online experiences through extranet changes to meet ongoing regulatory, business, and customer requirements, develop and enhance B2C & B2B portals and the LBA online experience.
- Scale Web Chatbot and Live Chat solutions.
- Use SAP MCF to support dynamic interactive voice response and increase self-serve capabilities.
- Optimize core customer service and billing applications.
- Enable marketing campaigns on SAP CIS and on the extranet to enhance marketing campaigns and communications.
- Extend appointment scheduling on customer online accounts to enable online MXGI meter exchange scheduling.
- Continue to build analytics capabilities, customer analytical records and models, and build and refresh dashboards.

5.8.7 Application Infrastructure Software

The Application Infrastructure Software asset subclass encompasses software products and tools that support and serve as the platform environment for IT solutions. Some of the key components of this asset subclass include database software used to store data for various applications, application deployment and execution software, integration software used for interfacing between applications and services, and reporting tools.

5.8.7.1 Condition Methodology

The condition of application infrastructure software is evaluated on the following:

- Ability to meet the vendor's support refresh life cycle strategy
- Ability to support key foundational software required for business applications

5.8.7.2 Condition Findings

Table 5.8-6 outlines the current age and state of key application infrastructure software used at EGD:

Table 5.8-6: State of Application Infrastructure Software

APPLICATION	APPLICATION OVERVIEW	AVG. AGE (YRS)	YEAR(S) SINCE LAST REFRESH	APPLICATION STATE
DataStage	Extract, transform and load (ETL) integration tool	16	7	Upgrade to current version scheduled for 2019.

APPLICATION	APPLICATION OVERVIEW	AVG. AGE (YRS)	YEAR(S) SINCE LAST REFRESH	APPLICATION STATE
Harvest	Source code management software	18	6	Software is current and supported.
HP Quality Assurance and Testing Suite	Testing and quality assurance tool suite	15	3	Software is current and supported.
Microsoft SQL Server	Database management software	20	4	Upgrade to current version scheduled for 2019.
Oracle Database	Database management software	19	1	Upgraded to current version in 2017. Software is current and supported.
Oracle Fusion	Integration suite providing interfacing capabilities between applications	10	1	Upgraded to current version in 2018. Software is current and supported.
Oracle Golden Gate	Data replication software	3	3	Software is current and supported.
Oracle WebLogix Application Server	Application deployment and execution of applications	15	1	Upgraded to current version in 2018. Software is current and supported.
SAP Business Objects Reporting Suite	Suite of reporting tools for business reporting & analytics	10	2	Upgraded to current version in 2016. Software is current and supported.

5.8.7.3 Risk and Opportunity

A number of consequences were identified if application infrastructure software are not maintained or renewed when needed:

- Inability to meet business needs and requirements, reducing overall productivity
- Cybersecurity exposure due to the inability to apply security patches to End-of-Support software, potentially leading to reputational impact if any breaches occur
- Decreased productivity due to extended application and system outages
- Increased safety risk if systems providing functionality for emergency calls are unavailable
- Financial risk due to outages and potential security breaches, resulting in loss of revenue
- Inability to meet financial and reporting compliance requirements
- Decreased customer satisfaction due to unavailable client-facing systems
- Increased maintenance costs due to reactively addressing required software and hardware repairs

5.8.7.4 Strategy

A proactive replacement strategy is in place for application infrastructure software, driven by forecasted changes of existing software applications and business requirements. Maintenance is reactive - performance issues or software bugs are addressed as they are identified. The application infrastructure software systems identified for upgrade/renewal in the next three years are:

- Microsoft SQL Server instances and databases
- Oracle Database instances and databases

- Oracle WebLogic application servers and Oracle Fusion integration software
- DataStage ETL/integration software
- SAP Business Objects reporting software

From 2022 onwards, the average historical spend profile is used to forecast future TIS spend as needs are identified and scope is refined.

5.8.8 Mobile Devices

Mobile devices consists of smartphones, cell phones, and Push-to-Talk radios. The industry best practice to replace mobile devices is two to three years, which aligns with smartphone manufacturers' release cycles, as well as the typical data plan contract.

5.8.8.1 Condition Methodology

The condition of mobile devices is not proactively monitored. If these assets experience failures or signs of operating issues, the user contacts the TIS Service Desk. In addition, the TIS asset class relies on new hire and business needs requests for equipping new mobile device users.

5.8.8.2 Condition Findings

Annually, there are approximately:

- 500 mobile device requests
- 140 incident requests requiring mobile device replacement

5.8.8.3 Risk and Opportunity

There are consequences to EGD if mobile device assets are not maintained or renewed:

- Inability to respond to emergency field situations
- Inability to resolve off-hours on-call situations for the reliable and safe operations of EGD's systems and networks

5.8.8.4 Strategy

The TIS Asset Class strategy for mobile devices is to stay one release cycle behind manufacturer releases as mobile devices are available at much lower cost. As such, mobile devices have a proactive replacement strategy of every three years driven by industry best practice and release cycles.

Mobile devices are reactively maintained to address performance issues and damaged/broken devices on an as-needed basis within the three-year replacement window. Approximately 400 devices are replaced annually as per the refresh strategy.

EGD uses historical spend to project the capital requirements for the replacement of mobile devices.

5.8.9 Field Devices

Field devices include printers and multi-function devices, GPS devices, truck modems for signal strengthening, and regional scanners.

5.8.9.1 Condition Methodology

The following inputs are used to assess the condition and suitability of field devices:

- Incident requests logged in ServiceNow
- Feedback from end users on field device performance
- Business needs driving field devices requirements

5.8.9.2 Condition Findings

Typically, field devices experience an elevated level of breakage and performance issues by the fourth year of use. Due to exposure to tough working conditions, field devices experience significant wear and tear, requiring maintenance on a frequent and reactive basis.

5.8.9.3 Risk and Opportunity

There are consequences to EGD if field devices are not maintained or renewed:

- Inability to respond to emergency field situations due to device unavailability
- Loss of productivity due to increased time spent travelling between office and job sites

5.8.9.4 Strategy

The majority of field devices have a four-year replacement strategy, based on industry best practices and EGD's condition experiences. Some assets (such as truck modems) do not have an industry-directed replacement cycle and are reactively replaced as they fail. TIS uses historical spend to project the capital requirements for the replacement of field devices.

5.8.10 Technology and Information Services Capital Expenditure Summary

The summary of projects and programs under the TIS asset class accounts to $241M from 2019 to 2028, as summarized in **Table 5.8-7.** The TIS capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.8-7: TIS Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
CIS Replacement	16,400	4,000	-	-	-	5,000	5,600	-	-	600	31,600
Customer Experience Transformation	7,000	-	-	-	-	-	-	-	-	-	7,000
Hardware	1,270	2,400	2,715	4,070	3,000	4,215	3,205	3,620	3,030	2,100	29,625
Software	14,965	15,845	18,570	20,166	18,966	12,751	12,161	18,346	18,936	19,266	170,972
Communication	250	250	250	175	175	175	1,175	175	175	175	1,975
TIS Total	**39,885**	**22,495**	**21,535**	**24,411**	**22,141**	**22,141**	**22,141**	**22,141**	**22,141**	**22,141**	**241,174**

5.9 BUSINESS DEVELOPMENT

5.9.1 Business Development Objectives

The Business Development asset class evaluates emerging technologies and trends in the industry. The objectives of the Business Development Asset Class are described in **Table 5.9-1**.

Table 5.9-1: Asset Class Objectives

ASSET CLASS OBJECTIVES		MEASURE OF SUCCESS
Deliver the energy people need and want	Implement strategies and new technologies to develop new platforms for growth and diversification.	• Opportunity's Return on Investment
	Evolve business practices to meet changing policies and/or emerging trends.	• EGD's adherence to evolving external policies and regulations
	Ensure EGD is positioned to deliver the energy people need and want.	• EGD's share of the energy market by operating segment
	Evaluate alternative investments to identify solutions that provide the most value for EGD's customers.	• Opportunity's Return on Investment
Integrity and Reliability	Continuously evolve the understanding of condition and risk associated with existing Business Development assets and utilize cost, risk, and performance information to drive asset-related decisions.	• Risk mitigated and LRROI • QRA completion %

EGD's Life Cycle Management Policy for Business Development can be found in **Table 5.9-2**.

Table 5.9-2: Life Cycle Management for Business Development

LIFE CYCLE STAGE	ACTIVITIES
Acquire/Create	• Identify emerging opportunities for EGD. • Evaluate opportunities to ensure alignment with organizational goals, operating models are defined, and planned investments are appropriate. • Understand customer preferences to provide the energy people need and want. • Implement new business models or operating assets that are economically feasible and sustainable for customers. This includes consideration of new regulatory applications to propose new lines of business and/or emerging policies.

LIFE CYCLE STAGE	ACTIVITIES
Utilize	• Commission smaller scale pilots and initial business offerings to ensure the technology is viable and appropriate implementation plans are in place. • Transition assets and/or processes to the appropriate operating unit.
Maintain*	• Maintain integrity of assets to minimize loss of containment, extend asset life and ensure compliance with codes, standards and established procedures.
Renew/Retire*	• Develop proactive renewal programs for assets that are nearing end-of-life (informed by data and tacit knowledge). • Retire assets using a process that meets or exceeds codes and standards.

**For NGV assets*

Business Development projects included in this Asset Management Plan are limited to projects related to rate-regulated activities.

5.9.2 Business Development Inventory

At this time, the inventory for Business Development consists of Natural Gas for Transportation (NGT) assets only.

NGT inventory is categorized based on the size and the type of NGT station:

Rental Refueling Stations – Large and Mobile: Large and Mobile NGT stations are used for medium duty and heavy duty trucks. These stations are custom-built and use a variety of equipment and components.

Rental Refueling Stations – Small: Small NGT stations are used for smaller vehicles such as ice cleaning machines, forklift trucks and individual light duty vehicles. These stations are equipped with a single-unit Vehicle Refueling Appliance (VRA), have limited fueling capacity, and do not require customized designs or installations. A small NGT station is often referred to as a VRA.

Utility Refueling Stations: Utility refueling stations are installed on EGD premises and are exclusively used by EGD for its own fleet fueling requirements. A utility refueling station is similar in build to a Large NGT station.

Table 5.9-3: NGT Inventory

INVENTORY – NG FOR THE TRANSPORTATION INDUSTRY	QUANTITY
Rental Refueling Stations – Large and Mobile	**7**
Public Refueling Site – Personal/Commercial Vehicles	1
Garbage Trucks, Pick-up Trucks/Vans – Commercial Customer Sites	6
Rental Refueling Stations – Small (VRA)	**194**
Arenas – Municipalities/Arena Operators	105
Fork Lifts – Industrial Customers	5
Pick-up Trucks/Vans – Commercial Customer Sites	37
Emergency Standby Power – Multi-family Building Owners	11
Personal Vehicles – Residential Customers	36
Utility Refueling Stations	**19**
EGD Distribution Yards – Fleet Vehicles – Large	13
EGD Distribution Yards – Fleet Vehicles – Small (VRA)	6

**Inventory count is current as of May 2018 and is based on station count. Note that customers can have more than one station.*

5.9.3 Business Development Condition and Strategy Overview

ASSET SUBCLASS	AVG. AGE (YR)	CONDITION	RISK / OPPORTUNITY	MAINTENANCE STRATEGY	REPLACEMENT / RENEWAL STRATEGY
Large and Utility Natural Gas for Transportation (NGT) Stations	15	Third-party and internal compressor inspection results indicated that 13 sites were over 3,000 operating hours (the manufacturer recommendation) and showed signs of deterioration, requiring a compressor rebuild. General wear and tear on asset components was also identified (e.g., worn valve faces, gaskets, etc.) as needing replacement.	Failure to maintain Natural Gas for Transportation (NGT) assets will result in declining equipment health, which could lead to the following risks: *Safety Risk*: Loss of containment *Financial Risk*: Repair, commodity loss, and potential property damage costs *CSAT Risk*: GHG emissions, negative environmental impact, and reputational risks	Bi-weekly onsite operational inspection of station components.	The strategy for existing large and Utility NGT stations is to have a program that: • Uses condition information based on periodic on-site inspections to maintain station integrity and supply reliability • Proactively replaces compressor blocks • Proactively upgrades equipment components as new technology becomes available • Updates station records to be compliant with Engineering standards In addition, EGD has a strategy to service new NGT large station customers, and to install and maintain the necessary fueling equipment. Business Development's marketing and execution teams work together to ensure successful implementation.
Small NGT Stations/ Vehicle Refueling Appliance (VRA)	30	General wear and tear on asset components was identified through a condition assessment (e.g., worn valve faces, gaskets, etc.) as needing replacement.	Failure to maintain NGT assets will result declining equipment health, which could lead to the following risks: *Safety Risk*: Loss of containment *Financial Risk*: Repair, Commodity loss, and potential property damage costs *CSAT Risk*: GHG emissions, negative environmental impact, and reputational risks	Quarterly onsite operational inspection of station components.	The strategy for existing Vehicle Refueling Appliance (VRA) stations is to have a program that: • Uses condition information based on periodic on-site inspections to maintain station integrity and supply reliability • Proactively replaces and upgrades VRA compressors and remote panels In addition, EGD has a strategy to service new VRA station customers, and to install and maintain the necessary fueling equipment. Business Development's marketing and execution teams work together to ensure successful implementation.
Community Expansion	N/A	N/A	Community expansion is a growth opportunity to provide natural gas services to communities not currently being serviced by EGD.	Assets will be maintained according to their asset specific requirements (outlined in the appropriate asset class section).	EGD's **Community Expansion Strategy** is to continue assessing and pursuing opportunities to provide gas distribution service to under-served communities. The process will require submitting applications to the Ontario Ministry of Infrastructure for approval to proceed as well as the subsequent submissions of Leave to Construct (LTC) applications to the OEB.
Lower-carbon Strategies	N/A	N/A	Lower-carbon strategies are a growth opportunity in line with the province's overarching climate change initiative to achieve GHG reductions and reduce negative environmental impact.	Assets will be maintained according to their specific requirements.	**Lower-carbon strategies** include exploring alternative energy sources, such as: • Energy Efficiency or DSM • Renewable Natural Gas (RNG) • Hydrogen Blending (Power-to-Gas) • Geothermal For the purposes of this Asset Management Plan, these lower-carbon initiatives (with the exception of DSM and hydrogen blending) are not currently included in rate-regulated activities, but are included in this Asset Management Plan to outline these important business development strategies for EGD.

5.9.4 Natural Gas for Transportation (NGT)

Traditionally, fleet operators fuel their vehicles with gasoline or diesel. EGD promotes the use of natural gas to these customers as an alternate fuel source to provide a lower-cost and lower-emission fueling solution for vehicles such as garbage trucks, light duty vehicles, and transit buses. Business Development is responsible for the installation, maintenance, and the safe and continued operation of NGT stations assets for these customers. NGT stations differ in operation from distribution system stations as NGT stations use and store compressed natural gas (CNG) on site at up to 4000psi.

EGD has two general categories for NGT station types: Large, Mobile and Utility NGT stations and Small NGT stations (also referred to as VRAs). Large, Mobile and Utility NGT stations are similar in operation and will be evaluated for condition in the same manner.

Table 5.9-4: NGT Station Components by Type

LARGE, MOBILE AND UTILITY NGT STATIONS	SMALL NGT STATIONS
• Electrical systems • Gas dryers • Compressors • Above-ground piping and tubing • Underground piping • Storage cylinders • Fuel control panels • Dispensers and hoses • Fill pressure control systems • Trailer body (for mobile fueling only)	• Vehicle Refueling Appliance (VRA) • Remote control panels • Gas detector • Hoses • Storage cylinders (where applicable) • Above-ground piping and tubing (where applicable)

EGD is continually working to promote and grow its NGT business. Business Development's Marketing Solutions team promotes the economic and environmental benefits of using natural gas as a vehicle fueling source through marketing opportunities such as trade shows, industry networking events, and approaching potential customers. For interested customers, the Business Development Marketing Solutions and Execution groups provide customers information on NGT station design, installation, operation and maintenance. Once completed, the parties move through a planning phase outlining requirements, scope, and costs associated with the station for contract finalization.

EGD's NGT station rental rate is based on a regulated rate of return with a Profitability Index of 1.0, with maintenance costs on a fully recoverable basis from the customer. These terms are locked in a long-term contract. By providing NGV fueling equipment to customers on a rental basis, EGD can achieve growth in the marketplace while fully recovering costs.

EGD currently services 201 external customers and 19 internal EGD sites with NGT stations for fueling fleet. The integrity and reliability of these existing stations are maintained according to the condition methodology outlined in **Section 5.9.4.1**. Currently, the Business Development group is working with 12 potential customers interested in services provided by EGD's NGT station rental program. A summary of the current state of these potential customers is outlined in **Section 5.9.4.4**.

Figure 5.9-1 is an example of a typical Large or Utility NGT station. A typical Small NGT station (VRA) is illustrated in **Figure 5.9-2**. A typical Mobile NGT station is illustrated in **Figure 5.9-3**.

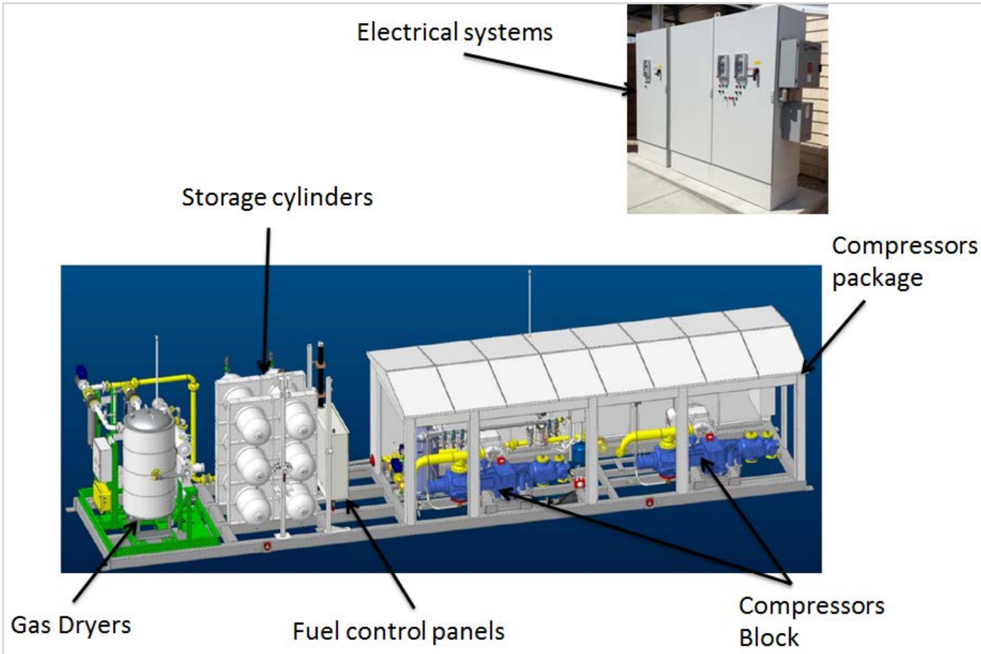


Figure 5.9-1: Large and Utility NGT Station

Figure 5.9-2: Small NGT Station

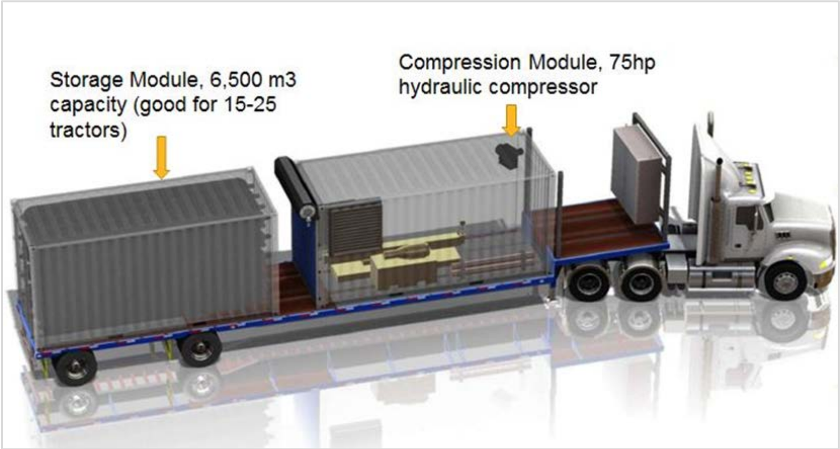


Figure 5.9-3: Mobile NGT Station

5.9.4.1 Condition Methodology

Evaluating the health of NGT station components is critical in understanding the overall health of each station. Evaluation results identify the necessary rebuilds and replacements required to ensure the safe and reliable operation of all stations.

NGT stations are assessed on a regular basis - small NGT stations are assessed quarterly; large, mobile and utility NGT stations are assessed biweekly. Biweekly and quarterly inspections were implemented in 2017 to continuously improve the approach to understanding and maintaining assets for the NGT program, following detailed third-party assessments in 2016 to 2017.

Large, mobile and utility NGT station assets are evaluated for the condition criteria in **Table 5.9-5**. **Table 5.9-6** lists the condition criteria used to evaluate small NGT stations.

Table 5.9-5: Large, Mobile and Utility NGT Station Condition Evaluation

STATION COMPONENT	CONDITION EVALUATION
Compressor	• Operating parameters (e.g., pressure, temperature, and run-time) for each compressor are correct. • Physical condition and operation of compressor components are adequate (i.e., no vibration, leaks, and damages). • Over- and under-pressure protection devices operate at specified set points, and capacity is adequate for use (responds appropriately to changes in outlet pressures and flows).
Storage Cylinders, Dispensers and Hoses, and Above-ground Piping/Tubing	• Physical condition and operation of components are adequate (i.e., no leaks or damages). • Over-pressure protection devices operate at specified set point (i.e., relief valve).
Gas Dryer	• Physical condition and operation of dryer components are adequate (i.e., no leaks or damages). • Moisture content is adequate.
Electrical Systems	• Electrical components are performing adequately.
Fuel Control Panels and Fill Pressure	• Valve performance is adequate. • Physical condition and operation of control systems are adequate (i.e., no leaks

STATION COMPONENT	CONDITION EVALUATION
Control Systems	or damages).
Underground Piping	• Pressure gauges are checked to ensure there is no pressure loss from main source (i.e., no leaks).
Trailer	• Tires and trailer body are inspected for physical condition

Table 5.9-6: Small NGT Station Condition Evaluation

STATION COMPONENT	CONDITION EVALUATION
Vehicle Refueling Appliance (VRA)	• Operating parameters (e.g., pressure, run-time) for each VRA are correct. • Physical condition and operation of VRA components are adequate (i.e., no leaks or damages) • Over-pressure protection devices operate at specified set point (i.e., relief valve).
Storage Cylinders and Above-ground Piping/Tubing	• Physical condition and operation of components are adequate (i.e., no. leaks or damages) • Over-pressure protection device operates at its specified set point (i.e., relief valve).
Remote Panel	• Start-up and stop operations are adequate. • Fan is functioning adequately. • Remote panel signalling to gas detector is functioning adequately.
Gas Detector	• Gas detector functionality is adequate.
Hoses	• Physical condition and operation of hoses are adequate (i.e., no leaks or damages).

When deficiencies are identified, corrective actions are taken according to the scope and severity of the deficiency, which can include regular day-to-day maintenance repairs, larger replacements, or rebuilds.

In addition, the Business Development group consistently investigates industry practices for the safe and reliable operation of its NGT assets. As technology advancements become available, EGD proactively evaluates the suitability of incorporating these improvements into its existing and new NGT sites.

5.9.4.2 Condition Findings

Large, Mobile and Utility NGT Stations: In 2016, internal and third-party inspections were conducted for compressor blocks in large NGT stations. It was found that 13 sites required a compressor block rebuild due to assessed condition and because the compressor blocks were not rebuilt since original installation.

Since then, EGD has remediated six out of the 13 necessary rebuilds; the remaining seven are currently in progress and on track to completion. EGD continues to inspect large NGT stations on a biweekly basis and is currently using the manufacturers recommended timeframe of 3000 operating hours as the basis for rebuilding compressor blocks. Based on average usage, it is anticipated that a rebuild will be required approximately every three to four years. EGD continues to monitor compressor operating hours, as per the new condition inspection framework outlined in Section **5.9.4.1**, to determine the priority of compressor replacements.

In 2017, a third-party NGT station assessment (see **Section 5.9.4.1**) determined that some station components (varying by site) showed signs of deterioration and needed to be replaced. Key findings were as follows:

- Leaks due to worn gaskets, worn valve faces, and environmental conditions
- General wear and tear of valves and other compression equipment

In addition, 24 large and utility stations require formal station design records to comply with newly-released Engineering policies.

Small NGT Stations (VRAs): Annually, there are approximately 30-35 VRA stations that have a compressor and/or remote panel that reach end-of-life and require rebuild. Approximately five VRA gas detectors reach their end-of-life every year, needing replacement.

5.9.4.3 Risk and Opportunity

There are a number of consequences that EGD and NGT customers can experience if NGT asset condition is not maintained. Failure to maintain NGT assets will result in deterioration of the equipment, which could lead to safety risks such as gas leaks on compressed gas infrastructure, corrosion of electric equipment, and possible over-pressurization of the system. These failures could in turn lead to inefficient and unreliable equipment performance, causing excessive downtime and increased fuel costs for the end user (i.e., not realizing the true benefits of reduced GHG emissions achieved through NGT). Sub-optimal equipment performance will result in a decline in customer satisfaction, leading to customers abandoning natural gas as a vehicle fuel. As a result, EGD will find it difficult to grow and retain its NGT customer base, leading to missed revenue generating opportunities and the possible loss of long-term NGT contracts.

5.9.4.4 Strategy

Two distinct strategies exist for NGT assets at EGD: a New Asset Strategy and an Existing Asset Strategy.

New Asset Strategy

The New Asset Strategy involves the acquisition of new large and mobile NGT and small VRA station customers and the installation of the necessary fueling equipment. The timing and scope for new NGT assets are based on the likelihood of contract confirmation and historical station installations of similar size and scope.

For large and mobile NGT stations, EGD is in negotiations with 12 potential customers and has identified the following opportunities:

- A large municipality (one NGT station upgrade and one new NGT station installation for city fleet vehicles)
- A private fleet operator (new NGT station installation for fleet vehicles)
- A large municipal transit entity (new NGT station installation for fleet vehicles)
- Other interested companies with significant transportation operations for shipping and delivery
- Private operator (new mobile fueling station to fuel other fleet vehicles)

For VRAs, EGD is in negotiations with one potential customer (with multiple VRAs). EGD installs three to five VRAs annually.

Existing Asset Strategy

The Existing Asset Strategy involves the renewal and upgrade of existing stations to ensure the continued safe, efficient, and reliable operations of all NGT stations. This approach includes the following activities:

- Using condition information based on on-site inspections to maintain station integrity and reliability:

  Small NGT Stations (VRAs)
  - Proactively replacing/rebuilding VRA compressors (~35 units per year)
  - Proactively replacing/rebuilding remote panels (~33 units per year)
  - Reactively replacing gas detectors as needed (~5 units per year)

  Large, mobile and Utility NGT stations
  - Maintaining a proactive compressor block rebuild program (~3-4 units per year).
  - Reactively remediating station components due to findings from onsite condition assessments
  - Proactively replacing manual shut-off valves with automatic models when identified for replacement
  - Proactively replace tires based on condition assessment of mobile NGT trailers
- Installing PLCs on large and utility stations (two units per year)
- Upgrading all identified station records and upgrading the panel to be reflective of up-to-date station configuration over the next four years

5.9.5 Community Expansion

The communities in Ontario that remain without natural gas service are distant from existing gas distribution infrastructure, have relatively low numbers of potential consumers, and may have terrain that precipitates high construction costs. These factors have limited the ability of Ontario natural gas distributors to serve these communities, as economic feasibility requirements cannot be met.

In 2016, the OEB issued a decision in its generic proceeding on new community expansion, allowing for a System Expansion Surcharge (SES) which generates additional revenue, enhancing the economic feasibility of community expansion projects.

The Ontario government has stated it will enact policy to assist in the development of new infrastructure to allow for natural gas service to reach rural communities and rectify energy inequities for these communities. In September 2018, the Ontario government tabled *Bill 32: Access to Natural Gas Act, 2018,* designed to support a ratepayer funded model to help serve new communities with natural gas.

To determine which communities will be qualified for gas service expansions, EGD assesses the economic feasibility for potential expansion (the same process for PI calculation as outlined in **Section 5.1**)**.** To move forward with these projects, EGD will need to be able to recover the revenue differences associated with these projects in gas distribution rates. These projects will still require the OEB's approval of the Company's Leave to Construction (LTC) application, and the application of the SES.

Of the following four locations that were approved for Natural Gas Grant program funding by the Ontario Ministry of Infrastructure, only the Fenelon Falls project will proceed with expansion and some preliminary planning work has been underway for Scugog Island (**Figure 5.9-3**):

- Fenelon Falls, ON
- Scugog Island, ON
- Cornwall Island, ON
- Hiawatha, ON

A number of other communities are currently being assessed for further community expansion opportunities through the application of the SES and the implementation of *Bill 32*.

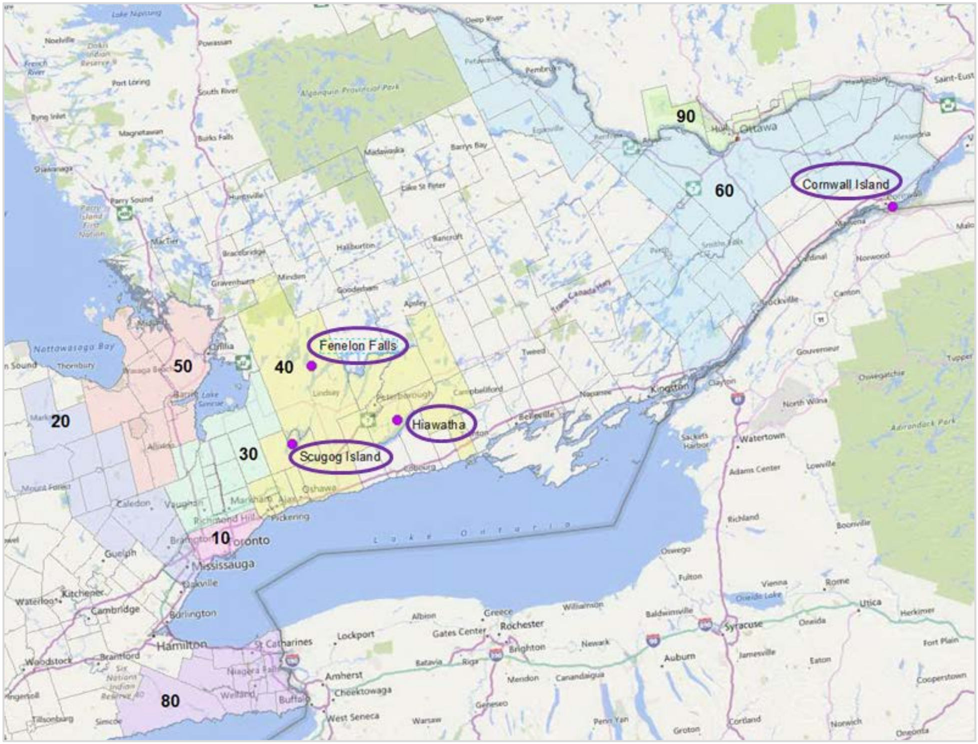


Figure 5.9-4: Approved Community Expansion Project Locations

5.9.5.1 Risk and Opportunity

Community expansion is a key business activity that helps grow and sustain EGD's core business and provides economic benefits to those served. As a result, there are a number of consequences that EGD could experience if community expansion activities are not pursued, including the potential loss of investment opportunities, the introduction of competition, and the potential negative impact to EGD's brand and reputation.

5.9.5.2 Strategy

The role of Business Development in community expansion is to interpret and participate in developing emerging policy, regulatory principles, and practices for community expansion projects. EGD's strategy is to continue assessing opportunities to provide gas distribution service to under-served communities. The process requires submitting applications to the Ontario Ministry of Infrastructure for approval to proceed and the subsequent submission of the LTC application to the OEB.

Once funding is secured and LTC applications are approved, the community expansion program is transitioned to the appropriate operations and maintenance groups for execution (design, planning, construction, and service delivery). The installed assets will then be considered under the appropriate asset class for continual evaluation of asset condition and risk.

Note: The Fenelon Falls LTC application has been approved by the OEB. Grants from Ontario Ministry of Infrastructure have been awarded and construction commenced in April 2018.

5.9.6 Lower-carbon Strategies

Governments at all levels are encouraging low carbon activities through regulations, code changes and other policy tools. This, in combination with Enbridge's desire to engage in a lower-carbon energy future, suggests an expanded view on what will constitute core natural gas utility business activities. With a change in the Ontario provincial government, Enbridge will continue to monitor and subsequently respond to the direction and requirements of the new government's carbon reduction strategy. Enbridge will also stay abreast of the federal carbon regulations and related obligations.

EGD's key lower-carbon strategies include:

- Energy Efficiency or Demand Side Management
- Renewable Natural Gas (RNG)
- Geothermal
- Hydrogen Blending (Power-to-Gas)

Other than DSM, lower-carbon initiatives are not currently included in rate-regulated activities but are included in this Asset Management Plan to outline these important strategies for EGD. EGD previously had proceedings with the OEB on its approach to GHG reduction strategies [*EB-2017-0224* and *EB-2017-0319*].

Currently, both RNG upgrading and injection facilities as well as geothermal initiatives are before the OEB in an effort to incorporate them under the regulated framework.

5.9.6.1 Energy Efficiency or Demand Side Management

EGD has offered energy efficiency and conservation initiatives known as Demand Side Management since 1995, pre-dating all carbon-related policies in Canada. DSM includes programs and activities that help consumers reduce their energy consumption to create a variety of benefits for society such as reduced energy bills, economic stimulus, environmental benefits, and benefits specific to low-income consumers. To align the utilities' interest with that of ratepayers, Ontario's energy regulator allows the utilities to claim an incentive if program results meet or exceed targets. Enbridge is currently in the middle of a six year DSM Plan (2015-2020).

Enbridge's DSM programs fall into three categories: Resource Acquisition (RA), Market Transformation and Energy Management (MTEM), and Low Income (LI). The RA Program seeks to achieve direct, measurable savings by using technical expertise, education and financial incentives to encourage customers to take up energy efficient equipment and practices. The MTEM Program focuses on facilitating fundamental changes to consumer and business behavior by helping customers better understand and actively manage their energy consumption. These programs typically operate where competitive market forces are unlikely to bring about change within acceptable timeframes. The LI Program type incorporates elements of both RA and MTEM, but is specially designed to address the unique challenges facing low-income consumers such as financial barriers and low awareness of efficiency measures.

Since 1995, EGD has helped customers reduce their consumption by 11.1 billion cubic metres of natural gas, enough savings to serve nearly 4.6 million homes for one year. These gas savings equate to a reduction of 20.8 million tonnes of GHG emissions, roughly equal to removing four million cars from the road for one year. As a result, DSM is not only economical for the ratepayer, paying for the cost through lifetime savings, but is also one of the most critical tools that will help Ontario support a lower-carbon future.

5.9.6.2 Renewable Natural Gas (RNG)

Both the province's *Climate Change Action Plan* and *2017 Long Term Energy Plan (LTEP)* reference renewable natural gas as an important part of the province's energy future. The LTEP expresses the provincial government's desire to leverage existing infrastructure (including gas appliances currently used by consumers) and to reduce GHG emissions. The RNG market in Ontario is nascent, and could be enhanced through the active participation of the province's natural gas distribution utilities. This is particularly important given the expectation that a Clean Fuel Standard (CFS) will be required by either or both the provincial and federal governments, and possibly implemented as soon as 2020. A CFS will impose a renewable content requirement on all fossil fuels, including natural gas.

EGD's completed Request for Proposal for RNG provides important information that will inform future expectations, policy, and regulation as the federal CFS is finalized and implemented. It will also encourage the development of RNG supply needed to satisfy the CFS. EGD has gained greater awareness of potential RNG technologies through sources such as the Canadian Gas Association (CGA), and is aligned with other CGA members on the importance of supporting technical advancements in this area.

As noted in EGD's RNG Procurement Plan, it is expected that the early adoption of renewable content in Ontario's natural gas system can be met with biogas originating from organic waste, such as forestry industry residue. Over the medium-term, increasing the supplies of renewable content will require the commercialization of promising technologies. Solutions can include biomass conversion to RNG through gasification. It can also include harvesting carbon dioxide from industrial processes to upgrade into RNG by incorporating green hydrogen with a catalyst. In effect, this becomes a means of recycling carbon dioxide back into renewable fuel to displace volumes of conventional natural gas, achieving deep de-carbonization within natural gas pipeline systems.

5.9.6.3 Geothermal

In 2018, EGD plans to implement a GHG emission abatement program to offset natural gas usage. The proposed Geothermal Energy Service program will be focused on making geothermal systems more broadly available and implemented for customers who would otherwise be using natural gas or other fossil fuels for space and water heating.

Geothermal systems provide space heating, water heating, and cooling functions and are electrically powered, highly efficient, and release no direct GHG emissions. A geothermal system consists of pipes in the ground called ground source loops (or geothermal loops) and a heat pump system functionally similar to a furnace/air conditioner combination appliance. The heat pump system is installed above-ground in the home and is connected to geothermal loops through pipes that go into the house. Geothermal loop and heat pump size is dependent on the size, amount of insulation, and design of the home. Geothermal systems are sized in tonnes of heating capacity. Typical homes in Ontario will require between three and five tonnes.

Geothermal systems work by transferring heat from and into the earth by circulating a liquid, such as ground water or an antifreeze solution, through the heat pump system. During the heating season, the heat pump system extracts heat from the liquid. This heat is then used to heat indoor air. The process is reversed during summer months, when heat is removed from indoor air and transferred to the earth by ground water or through an antifreeze solution. Geothermal systems can also be used with forced-air and hydronic heating systems.

EGD will own and maintain the geothermal loops and customers will own and maintain the heat pump system. EGD will be responsible for supplying and installing the geothermal loops and the owner will be charged a monthly service fee and will be required to provide EGD access to the property over the life of the geothermal loops. This is similar to the current gas distribution system approach, where the utility owns the gas supply infrastructure and the customer owns the gas appliances.

Geothermal systems have been available in Ontario for a number of years. However, the adoption of this technology has been hampered by its high initial cost compared to other building heating and cooling technologies and by inconsistent approaches used by different contractors. These factors have resulted in low market penetration and less than desirable levels of customer satisfaction with this technology.

Geothermal systems may be an important means to achieving GHG emission reductions in Ontario, as they are in other jurisdictions such as in the state of New York, USA.

5.9.6.4 Hydrogen Blending (Power-to-Gas)

EGD responded to the Ontario government's request to develop storage technology for the excess renewable electricity the province produces using Power-to-Gas technology. The technology converts excess power from sources such as wind and solar and stores it in the form of hydrogen. The project is divided into two phases: the Independent Electricity System Operator (IESO) project and the Blending project.

The IESO phase of the project involves the construction and operation of a Power-to-Gas plant to demonstrate the technology and provide grid balancing and frequency regulation services to the IESO. The Blending phase supports EGD's desires to introduce renewable content into the natural gas grid and future endeavors involving hydrogen. This project is supported by EGD's Engineering and Operations teams as well as other departments.

The approach to hydrogen blending involves technical due diligence and planning specific to EGD's gas distribution system to establish the initial guidance and capabilities for safely blending hydrogen into portions the natural gas pipeline network with the aim of attaining systemize blending. This work is a prerequisite for commencing field trials on hydrogen blending in a segment of EGD's pipeline network.

Compliance with the pending federal Clean Fuel Standard (CFS) will require increasing quantities of renewable fuel. Early market supplies of renewable fuel will be sourced from biomass which is available in limited quantities. To meet GHG reduction targets, additional supplies of renewable content will be required, to be derived from next-generation RNG technologies (which will also have hydrogen as part of their output gas). Also, opportunities like Power-to-Gas energy storage can be used as a supply of renewable content if the natural gas system can accommodate increased flexibility for different gas compositions. The MOECC has identified hydrogen as a source of renewable content for natural gas systems. Supplies of hydrogen are expected to be the first market opportunity requiring increased flexibility for different gas compositions in the natural gas system. The development of hydrogen blending capabilities from plants will be used to establish operational, safety, and integrity priorities, which will also be needed for larger market adoption of next-generation RNG technologies.

In 2018, EGD will continue to evaluate the opportunity to blend hydrogen into its existing gas infrastructure. This will include research into what has been accomplished in other jurisdictions (primarily Europe) and will involve working with North American companies (through the CGA and the American Gas Association (AGA)) to develop test protocols that will lead to the development of industry standards. EGD will also research and develop hydrogen pipeline standards for transportation of pure hydrogen to blending sites within its existing gas network. Additional staffing resources will be requested to coordinate this work and to continue research into hydrogen blending and other hydrogen opportunities within the lower-carbon economy. Funding may be sought to enable remaining research towards advancing the introduction of hydrogen into the energy market.

5.9.7 Business Development Capital Expenditure Summary

The summary of projects and programs under the Business Development asset class accounts to $45M from 2019 to 2028, as summarized in **Table 5.9-7**. The Business Development capital is further summarized as part of EGD's total 10-year capital plan in **Section 6.**

Table 5.9-7: Business Development Capital Summary ($ Thousands)

Program/Project Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10-Year Forecast
NGT Maintenance	686	698	710	758	596	606	617	627	638	649	6,586
Rental VRAs	250	254	259	263	268	272	277	282	287	292	2,704
NGT Rental Compressors (Non-Transit)	2,600	5,600	4,500	3,000	3,000	3,000	3,000	3,000	3,000	3,000	33,700
Hydrogen Blending	1,200	365	-	-	-	-	-	-	-	-	1,565
Business Development Total	**4,736**	**6,918**	**5,469**	**4,021**	**3,864**	**3,879**	**3,894**	**3,909**	**3,925**	**3,941**	**44,555**

Refer to **Section 6.3** for projects with expected spend that are not included in the capital summary.

6 Summary of Capital Expenditure

6.1 PORTFOLIO OPTIMIZATION

6.1.1 Business Case Preparation

In preparation for optimization, comprehensive business case governance reviews were completed on proposed business cases to ensure:

- Business case scope met EGD's capitalization policy.
- Business cases presented a well-articulated purpose, need, and timing aligned with asset class objectives and life cycle management strategies (**Section 5**).
- The scope definition and alternatives adequately addressed project risks and/or opportunities.
- The solution supported the asset management principles of balancing cost, risk, and performance.
- Execution risks were reasonable (resource capacity).
- Initiatives identified as mandatory were justified, based on:
    - Compliance requirements
    - Exceeding a risk limit where the risk is assessed within EGD's intolerable risk region
    - Third-party relocation driven
    - Program work with sufficient history and risk to warrant continuation

In total, 754 business cases were considered in the optimization of the 10-year plan. The preferred timing and proposed spend profile is illustrated in **Figure 6.1-1** from the PP-AMP levelling tool. The portion of the spend with fixed timing is depicted by a hatched pattern. Fixed projects are those that are in progress or identified as mandatory with no flexibility in timing.

6.1.2 Capital Considerations

The optimization process is based on management setting a capital constraint or threshold from which a portfolio of work driven by asset needs is defined. The capital constraint, termed optimization capital, is determined based on the defined regulatory framework and asset class objectives and strategies. Determining the optimization capital involves EGD's Asset Management, Finance and Regulatory departments. It may be necessary to run iterative optimization scenarios varying the optimization capital to determine the level of capital that best meets asset needs; this method may require analysis of multiple optimization scenarios when there is flexibility in defining the capital constraints.

To complete EGD's latest portfolio optimization, the outcome of the MAADs decision and the future impact to ratepayers were considered when establishing the optimization capital. On August 30, 2018, the Decision and Order was received from the OEB on the application to amalgamate EGD and UGL using an established regulatory framework for MAADs *[EB-2017-0306/EB-2017-0307]*. This decision provided EGD with the approved five-year (2019-2023) annual Incremental Capital Module (ICM) Materiality Threshold. EGD has been approved by the OEB to have access to rate recoveries for qualifying incremental capital investments over and above this Materiality Threshold through the OEB's Incremental Capital Module (ICM). The ICM Materiality Threshold was used to determine EGD's optimization capital from 2019 - 2023. For the years 2024 – 2028, the annual capital budget will represent management's spend threshold for each year that they feel best meets Ratepayer Rate impact with the utilities obligation to serve and maintain its plant (all rate base).**Table 6.1-1** summarizes EGD's Optimization Capital for the 10 year plan.

Table 6.1-1: Capital Constraint Determination

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM Materiality Threshold[11]	463 M	473 M	479 M	483 M	487 M	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Total Overhead	151 M	154 M	156 M	158 M	165 M	168 M	171 M	174 M	177 M	180 M
Optimization Capital	312 M	319 M	323 M	325 M	322 M	323 M	324 M	325 M	326 M	326 M

[11] Refer to **Table 6.4-1** in **Section 6.4**.

EGD's capital spend requirements up to the OEB approved ICM Materiality Threshold is described as Base Capital. To understand which projects would be considered incremental and potentially ICM-eligible, EGD applied the following descriptions of Base Capital and Incremental Capital to business cases for optimization:

Table 6.1-2: Base Capital & Incremental Capital Descriptions

TERM	DESCRIPTION
Base Capital	• Represents the ongoing capital requirements of the utility to maintain safe and reliable operations and to economically attach new customers and pursue opportunities for innovation • Driven by asset class strategies and programmatic work that has sufficient history and risk to warrant continuation • Supported by existing rates (through depreciation expense, annual Price Cap Index rate increases, or incremental revenues from customer growth)
Incremental Capital	• Represents discrete projects requiring an in-service capital investment of over $10M (from 2019-2023) • Refers to non-discretionary spend driven by asset class strategies and not supported by existing rates • Total incremental spend will include all capital costs associated with the identified project (including multi-year spend that falls outside of the project's in-service year when the ICM is to be requested).

To optimize the 754 business cases, EGD's PP-AMP leveling tool was used (refer to **Section 4.2.3**) where the optimization capital was set as the constraint (excluding overhead). Based on this value, the optimal capital timing was determined for proposed business cases.

6.1.3 Optimization Results

Portfolio optimization builds off of the most recent approved plan; the initial spend profile is the result of the previous optimization and approved portfolio, with the addition of new BCs and updates to existing BCs. The initial pre-optimized request for capital exceeded the optimization capital in all years but 2028 (represented by the red line in **Figure 6.1-1**).

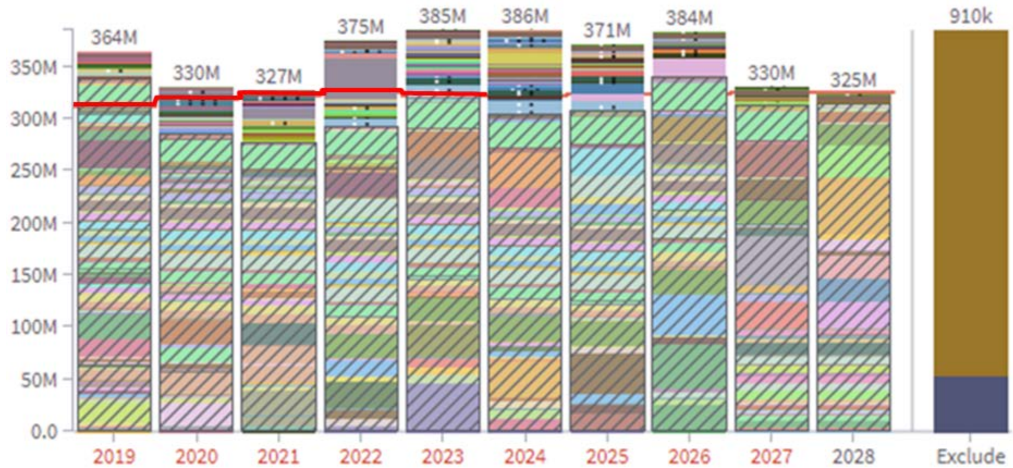


Figure 6.1-1: Pre-Optimized Spend Profile (PP-AMP Leveling Tool View)

Running the leveling tool (as outlined in **Section 4.2.3**) at the defined optimization capital (**Table 6.1-1**), an optimized solution could not be obtained. This was due to the level of fixed and mandatory projects. To resolve this, business cases that met the incremental capital criteria (**Table 6.1-2**) were removed from the leveling process and leveling was repeated until an optimized solution was obtained. Since ICM-eligible capital is different in kind from initiatives carried out through base capital, removing these initiatives from levelling provided EGD with the best understanding of an optimized typical base spend profile. ICM-eligible business cases (presented in **Table 6.1-3**) were considered in addition to the optimized result. Where possible, through subsequent reviews of the results, ICM-eligible capital was proposed within the optimization capital and treated as base (**Table 6.1-1**). The optimized result is illustrated in **Figure 6.1-2**.

Table 6.1-3: ICM-Eligible Capital Projects

Asset Class	Project Name	Driver[12]	In Service Year	Total In-Service Capital ($000s)
Pipe	NPS 30 Don River Replacement	Exceeds risk threshold	2019	$25,700
Pipe	NPS 20 Don River Relocation	Third party relocation	2020	$35,873
Storage	SCOR: Meter Area – Upgrade	Exceeds risk threshold	2020 | 2021	$43,600
Pipe	NPS 12 St. Laurent Ottawa North Main Replacement	Condition	2022	$52,132
REWS	Kennedy Road Expansion[13]	Condition	2022	$21,700
Pipe	NPS 12 Martin Grove Rd Main Replacement Phase 2	Condition	2024	$11,750
REWS	VPC Core and Shell Obsolescence	Condition	2025	$20,000
REWS	SMOC/Coventry Consolidated Facility	Condition	2026	$30,825

[12] For details on these projects refer to the asset class's Condition and Strategies Overview section (outlined in **Section 5**).
[13] This project is treated as base.

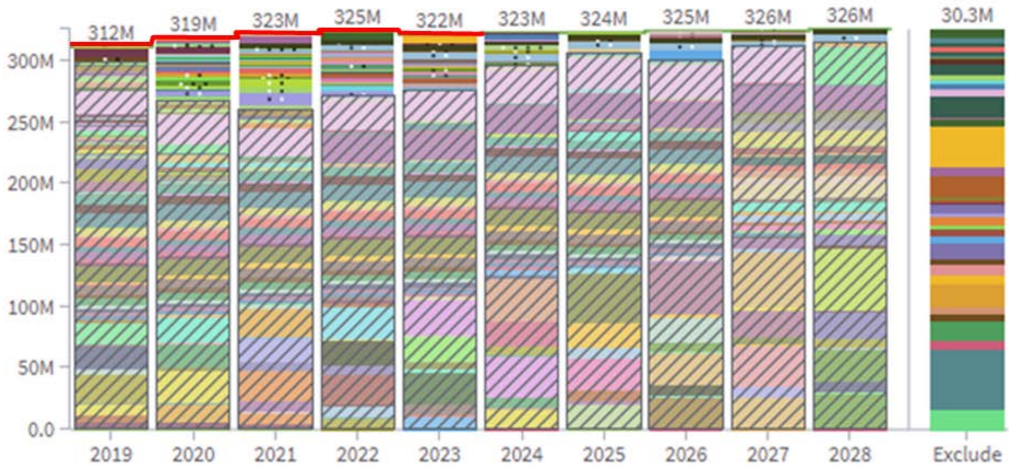


Figure 6.1-2: Post-Optimized Spend Profile (PP-AMP Leveling Tool View)[14]

The optimized result and ICM-eligible projects were reviewed with the ACMs, ACDs, and business stakeholders. Adjustments to these results were proposed and reviewed with all asset classes. These adjustments were driven by resource capacity, re-alignment with life cycle management strategies, and where possible, maintaining a total spend within the optimization capital. Adjustments were incorporated as necessary through consultation with the ACMs and using LRROI for project comparison.

Figure 6.1-3 presents the 10-year capital requirements by asset class. It can be seen that the capital requirements to meet asset class objectives and life cycle management strategies, while managing risk, exceed the capital available for optimization. From 2019-2023, the capital that exceeds the optimization capital (ICM Materiality Threshold less Total Overhead) qualifies as incremental capital per the definition in **Table 6.1-2**.

The final 10-year portfolio of spend was reviewed and approved by the ACDs and the AM Steering Committee.

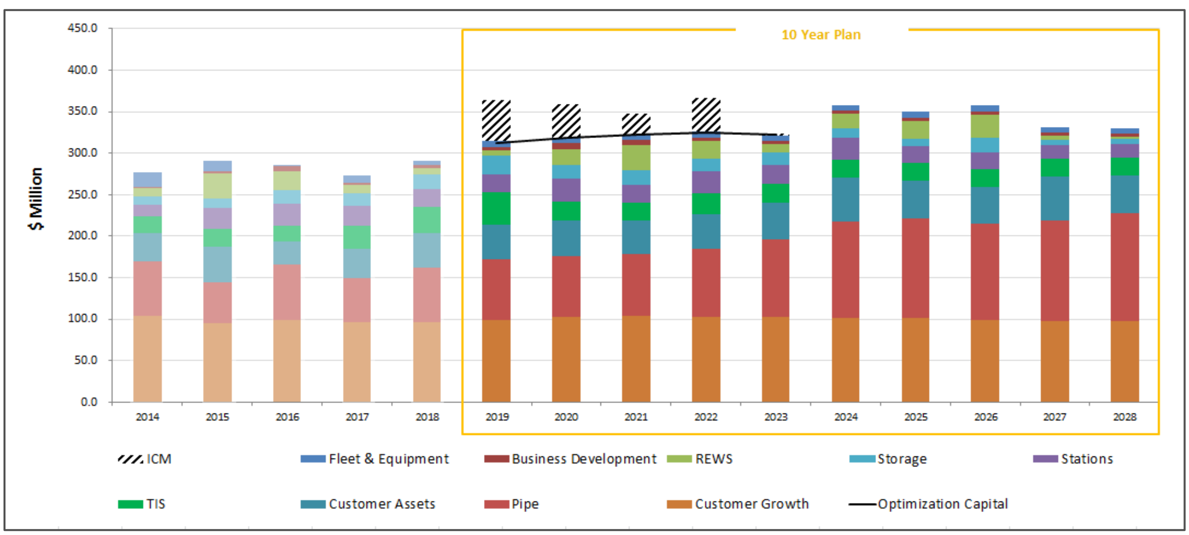


Figure 6.1-3: Final 10 Year Plan by Asset Class (with ICM)

[14] This profile does not include the ICM-eligible projects.

6.2 SUMMARY OF CAPITAL EXPENDITURE

The capital plan was optimized from 2019 to 2028 using the Asset Management Core Process (outlined in **Section 4.2**). The result addresses the organization's asset needs and includes known risks and opportunities requiring action over the next 10 years.

The portfolio optimization process examined 754 business cases for which 100%* of the capital request was risk assessed. The optimization considered business cases developed to address:

- Asset class objectives and life cycle strategies
- Known compliance requirements
- Identified risks within EGD's intolerable risk region
- Identified risks requiring a solution within a defined time window

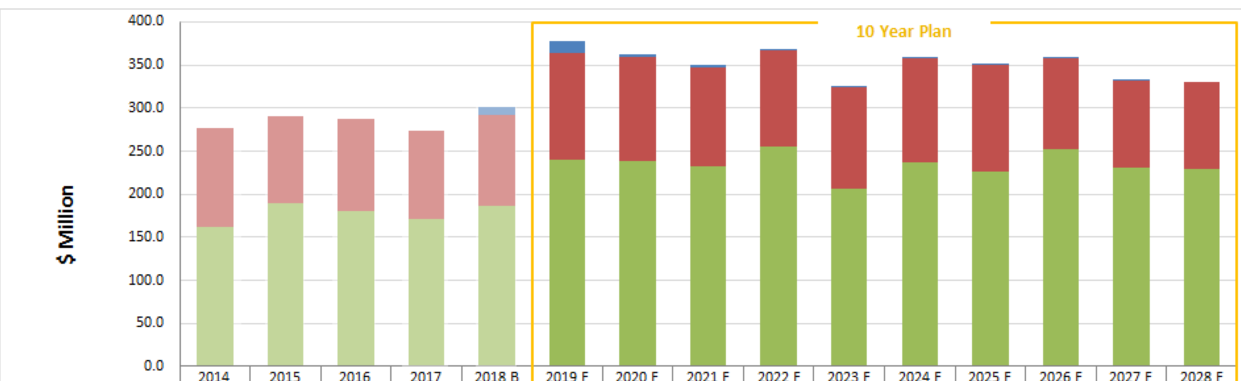
Note: Mandatory projects that are less than $100K and without a risk assessment are not included in this calculation.

As described in Portfolio Optimization (**Section 4.2.3**) project timing was determined based on risk reduction and projects identified as mandatory, which had specific timing requirements and mandates. Labour implications were also considered for routine maintenance activities to ensure that project pace and timing met life cycle strategies, adequately reduced risk, and identified as feasible.

The capital expenditure requirements fall into three categories:

- **Growth Capital:** Customer growth and reinforcement expenditures that will support the addition of new customers.
- **Maintenance Capital:** Expenditures related to existing assets to maintain safe and reliable business operations.
- **Community Expansion:** Expenditures for the expansion of the gas distribution network to remote communities that do not meet current *EBO 188* economic feasibility guidelines without a rate rider.

Figure 6.2-1 presents the direct 10-year capital profile and excludes capital overheads for EGD from 2019 to 2028, totaling over $3.5B in proposed asset expenditures. Projects with solution scopes still under development are not included in the 10-year portfolio of spend (outlined in **Section 6.3**).



	2014	2015	2016	2017	2018 B	2019 F	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
Community Expansion					9.8	13.3	3.0	3.1	2.0	1.3	0.7	0.7	0.5	0.7	0.0
Growth	114.5	101.8	106.7	101.7	104.7	123.2	121.9	114.6	111.8	118.4	122.1	123.4	104.9	101.7	101.3
MTC	162.5	189.0	179.8	171.3	186.5	240.4	237.7	232.8	254.8	206.0	236.2	226.4	252.6	230.0	228.6

Figure 6.2-1: EGD 10-year Capital Profile (2019 – 2028)

The overall portfolio has an LRROI of 119%. The breakdown by asset class has been summarized in **Table 6.2-1**. While different asset classes have higher or lower LRROI values, the value of lifetime risk reduced is greater than the capital investment. Refer to **Section 4.2.5** for a description of LRROI.

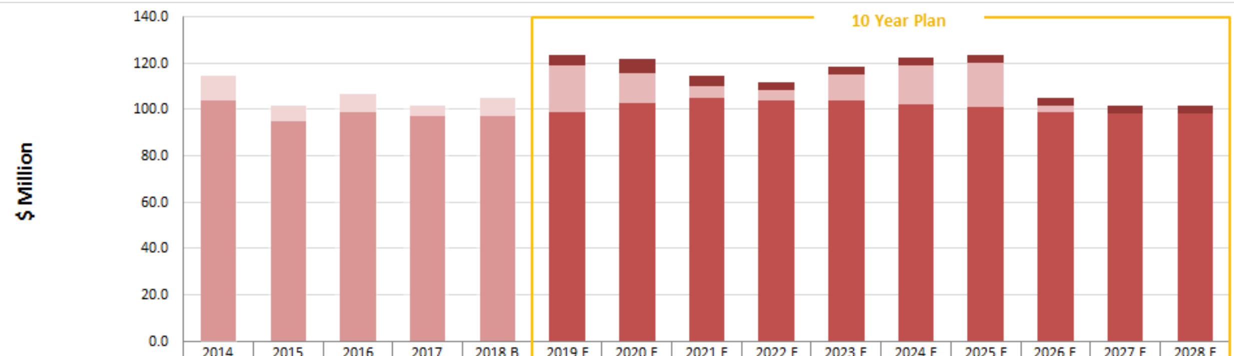
Table 6.2-1: Total LRROI

ASSET CLASS	LRROI
Business Development	110%
Customer Assets	136%
Customer Growth	164%
Fleet & Equipment	108%
TIS	162%
Pipe	41%
Real Estate Services	101%
Stations	82%
Storage	284%
Total	**119%**

6.2.1 Growth Capital

The current growth capital plan is comprised of Pipe, Customer Growth, and Business Development asset class initiatives. These asset classes contribute to the portfolio with the following types of initiatives (Refer to Figure 6.2-2):

- **Pipe:** Reinforce existing distribution networks to ensure the system has capacity to reliably meet current and future customer demands.
- **Business Development:** Equip new customers with rental refueling stations to use natural gas for transportation (NGV) and pursue opportunities for innovation.
- **Customer Growth:** Add new customers, upgrade existing customers, and fuel conversion to natural gas.



	2014	2015	2016	2017	2018 B	2019 F	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
Business Development						4.1	6.2	4.8	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Pipe	10.8	6.8	7.9	4.7	7.7	20.3	13.2	5.2	4.9	11.6	16.7	18.9	2.8	0.5	0.0
Customer Growth	103.7	95.0	98.8	97.0	97.0	98.8	102.5	104.7	103.6	103.5	102.1	101.2	98.8	97.9	98.0

Figure 6.2-2: Growth Capital Plan for Pipe, Business Development, and Customer Growth

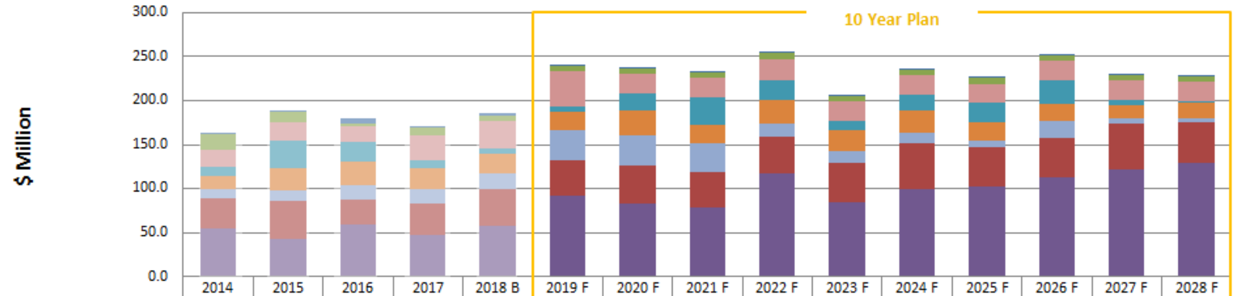
Pipe: On average, EGD has spent approximately $8M annually on reinforcements. Over the next 10 years, with expected growth, the annual spend is slightly higher than historical spend, with a range of spend between $3M to $20M annually from 2019 to 2026, due to identified network reinforcements.

Business Development: Historical actual spend for NGV was previously tracked under maintenance capital. On average, EGD has spent $3M annually (maintenance and growth combined). Growth capital for the Business Development asset class includes the addition of expected new NGV customers and the research and development of hydrogen pipeline standards for transportation of pure hydrogen to blending sites within its existing gas network. On average, the annual capital spend for business development growth is $3.8M. This may increase as demand for NGV increases over time.

Customer Growth: The 10-year customer growth forecast is aligned with historical actuals and calculated based on forecasted growth projections, as identified in the asset class' condition and strategies (see **Section 5.1**). The average annual spend is $101M from 2019 to 2028; slightly higher than the historical annual average of $98M.

6.2.2 Maintenance Capital

The maintenance capital plan is comprised of Pipe, Stations, Customer Assets, Storage, Fleet and Equipment, TIS, REWS and Business Development asset classes (see Figure 6.2-3).

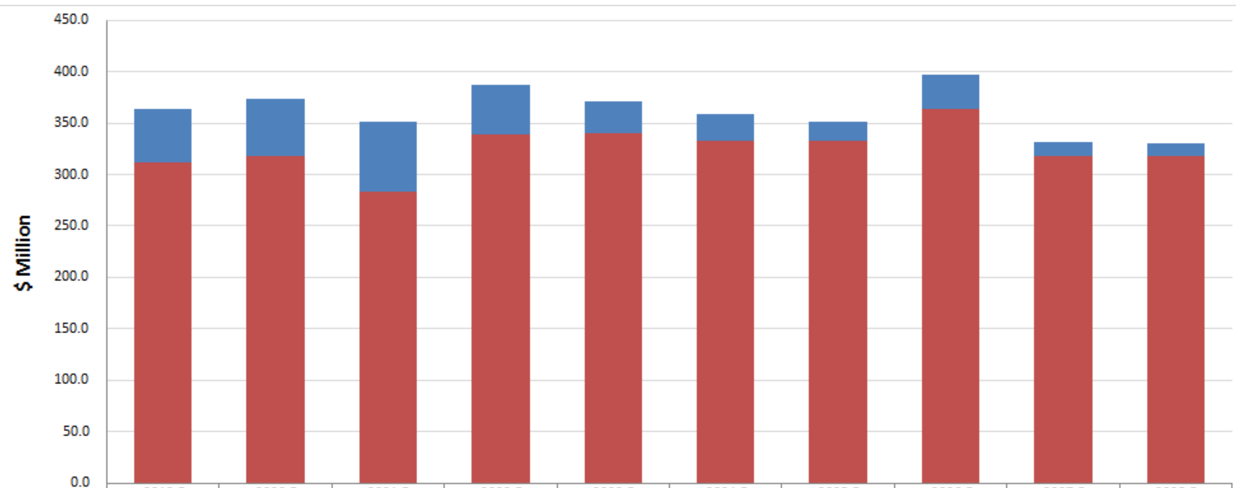


	2014	2015	2016	2017	2018 B	2019 F	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
Business Development	0.7	1.5	6.4	2.1	4.2	0.7	0.7	0.7	0.8	0.6	0.6	0.6	0.6	0.6	0.6
Fleet & Equipment	17.8	12.7	2.3	9.1	5.0	6.8	6.6	6.8	6.6	6.8	6.9	6.7	6.8	6.8	6.3
TIS	20.0	20.8	18.6	27.7	31.1	39.9	22.5	21.5	24.4	22.1	22.1	22.1	22.1	22.1	22.1
REWS	10.2	30.4	22.1	9.4	6.9	5.8	19.7	30.9	22.3	10.5	17.1	21.8	27.4	5.3	2.6
Stations	14.4	25.3	26.1	23.5	22.3	20.9	27.7	21.2	26.2	22.8	26.3	20.1	19.3	16.1	16.8
Storage	10.2	12.1	16.6	16.0	17.9	34.0	34.0	32.4	15.1	14.6	11.5	8.3	18.7	5.6	5.4
Customer Assets	34.2	42.8	28.9	35.7	41.4	41.0	43.6	40.3	42.6	44.2	52.2	45.0	44.6	52.4	44.9
Pipe	55.1	43.4	58.8	47.9	57.7	91.3	82.8	79.0	116.7	84.3	99.5	101.8	113.1	121.0	129.9

Figure 6.2-3: Maintenance Capital Plan

All capital requirements support the maintenance of existing assets based on the conditions and strategies outlined in Customers and Assets (**Section 5**). Timing is based on risk, asset life cycle strategies, and minimizing the impact to the ratepayer. **Figure 6.2-4** displays the projected 10-year profile of capital requirements that meet the mandatory criteria and all other expenditures. Mandatory investments are the result of a risk that must be addressed within its required time window, including:

- Compliance requirements
- Exceeding a risk limit where the risk is assessed within EGD's intolerable risk region
- Third-party relocation driven
- Program work with sufficient history and risk to warrant continuation



	2019 F	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
	51.9	56.2	67.1	48.9	31.2	26.1	18.6	33.2	13.4	12.0
Mandatory	312.2	317.4	283.9	338.4	340.2	332.7	332.8	364.2	318.3	317.9

Figure 6.2-4: Mandatory Spend Profile

6.2.2.1 Pipe

On average, EGD has spent $53M annually on maintenance capital for the Pipe asset class. The historical and projected 10-year spend profile is presented in **Figure 6.2-5**. The total maintenance capital spend for the Pipe asset class is forecasted to be between $79M and $130M over the 10 years identified.

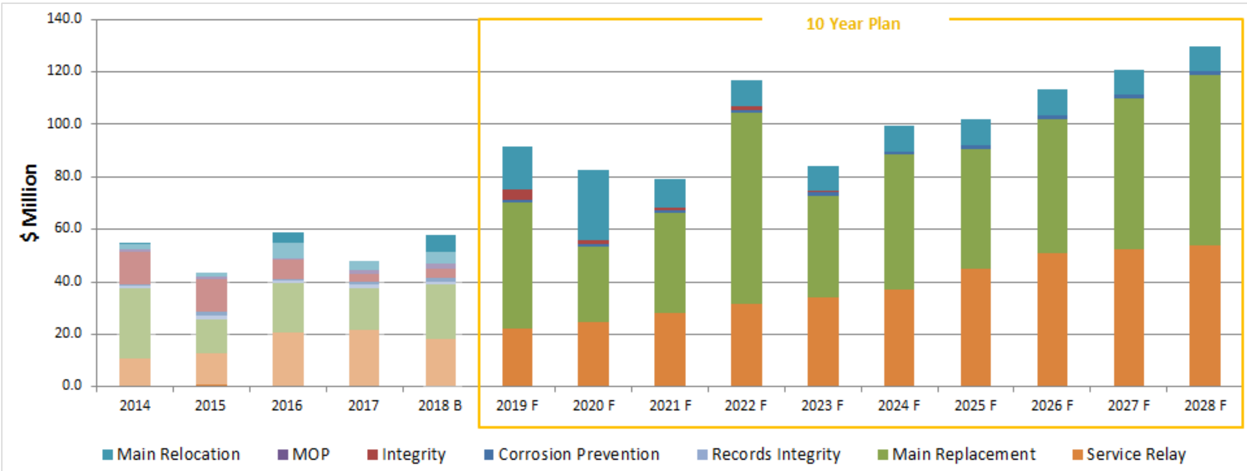


Figure 6.2-5: Maintenance Capital over Time for Pipe

The increase in capital requirements for the Pipe asset class is primarily driven by the following pipe and service initiatives:

Distribution Mains Replacement Programs:

- Planned spend to respond reactively to forecasted leaks and meet life cycle strategies for aging steel and plastic mains.
- Planned spend to further investigate and remediate a subset of vital mains (HP/XHP) identified through SMA knowledge and special direct assessments requiring attention. These pipelines require a large capital investment and are subject to the OEB's LTC process.
- NPS 30 Don River Replacement: Planned spend to replace the Don River bridge crossing, which in its current state presents an intolerable risk to EGD.

NPS 20 Don River Relocation: Planned spend to mitigate risk associated with third-party projects in conflict with the existing buried NPS 20 Lake Shore KOL pipeline.

AMP Fitting Replacement Program: Planned spend to proactively replace copper risers to meet the life cycle strategy for AMP fittings.

Refer to **Section 5.2** for further details on the Pipe asset class.

6.2.2.2 Stations

On average, EGD has spent $22M annually on maintenance capital for the Stations asset class. The historical and projected 10-year spend profile is presented in **Figure 6.2-6**. On average, the annual capital spend for the asset class is forecasted to remain at $22M over the 10 years identified.

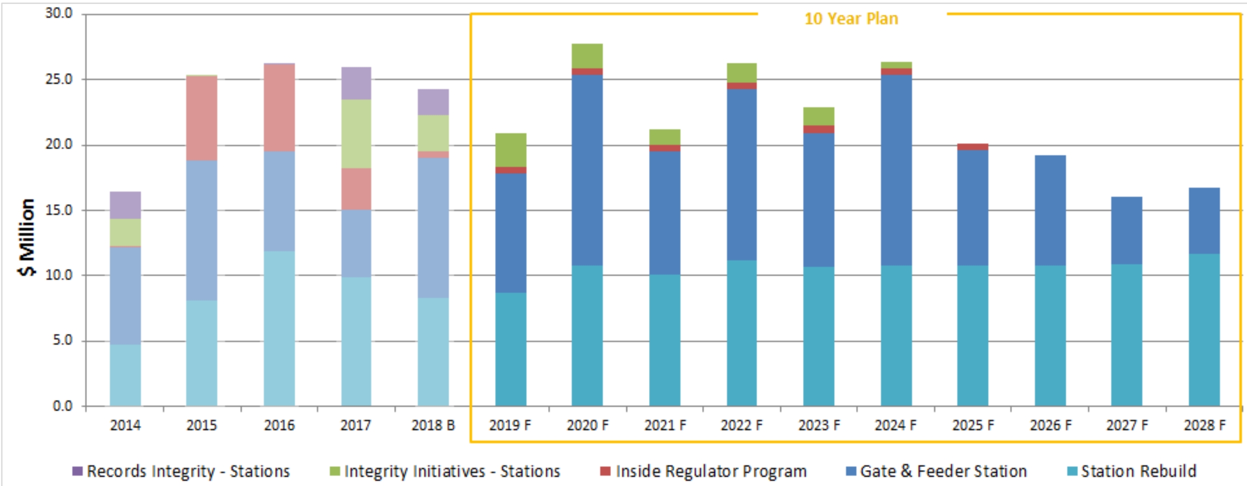


Figure 6.2-6: Maintenance Capital over Time for Stations

The main expenditure categories for the Stations asset class are for gate & feeder stations and station rebuilds. Programmatic activities for the asset class are supported by historical trends and life cycle strategies. Fluctuations in spend over the 10 years related to gate and feeder stations are due to varying risk and remediation requirements at specific station locations.

Refer to **Section 5.3** for further details on the Stations asset class.

6.2.2.3 Storage

On average, EGD has spent $15M annually on maintenance capital for the Storage asset class. The historical and projected 10-year spend profile is presented in **Figure 6.2-8**. On average, the annual capital spend for the asset class is forecasted to be $18M over the 10 years identified.

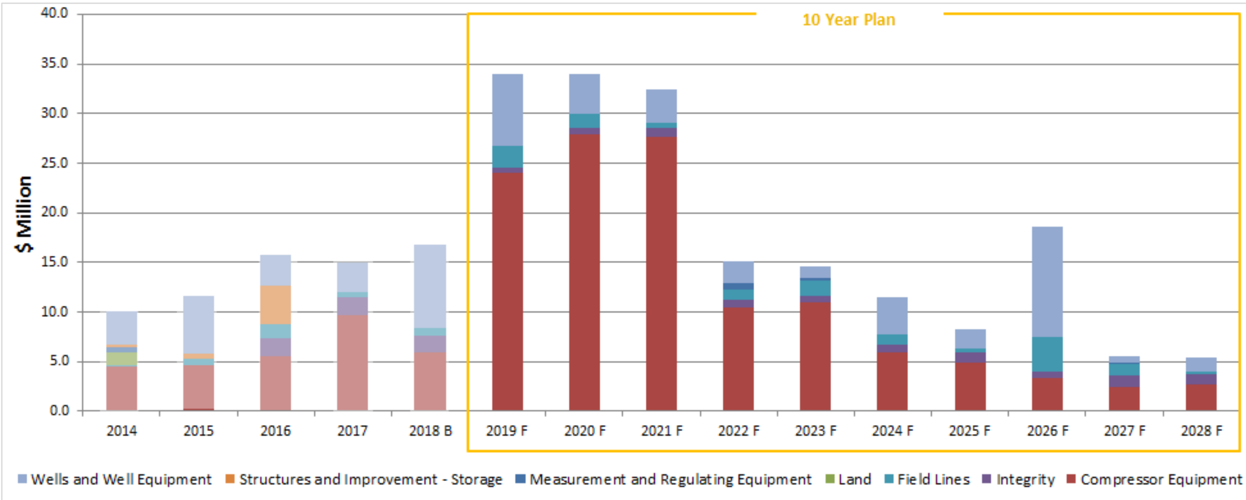


Figure 6.2-7: Maintenance Capital over Time for Storage

The increase in capital requirements for 2019-2021 is driven by the spend to replace the above-grade cross-flow header system and process piping in the Corunna meter area.

Refer to **Section 5.4** for further details on the Storage asset class.

6.2.2.4 Customer Assets

On average, EGD has spent $37M annually on maintenance capital for customer assets. The historical and projected 10-year spend profile is presented in **Figure 6.2-7**. On average, the annual capital spend for the Customer Assets asset class is forecasted to be $45M over the 10 years identified.

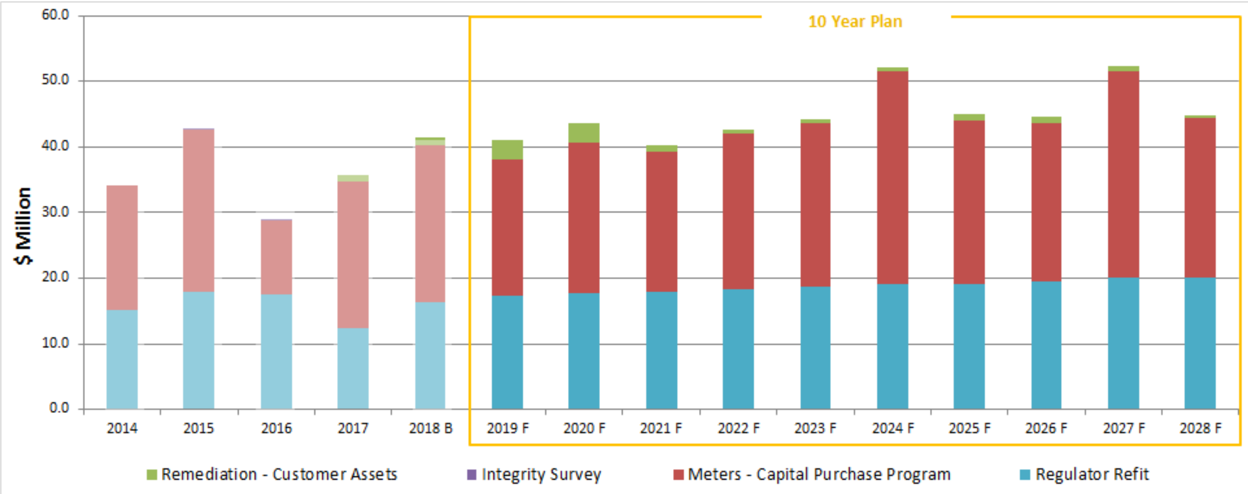


Figure 6.2-8: Maintenance Capital over Time for Customer Assets

The main expenditure categories for the Customer Assets asset class are the Meters Capital Purchase Program and regulator refits. The asset class spend profile is aligned with the asset class's life cycle management strategies.

Refer to **Section 5.5** for further details on the Customer Assets asset class.

6.2.2.5 Real Estate and Workplace Services

The historical and projected 10-year spend profile for the Real Estate and Workplace Services asset class is presented in **Figure 6.2-11**.

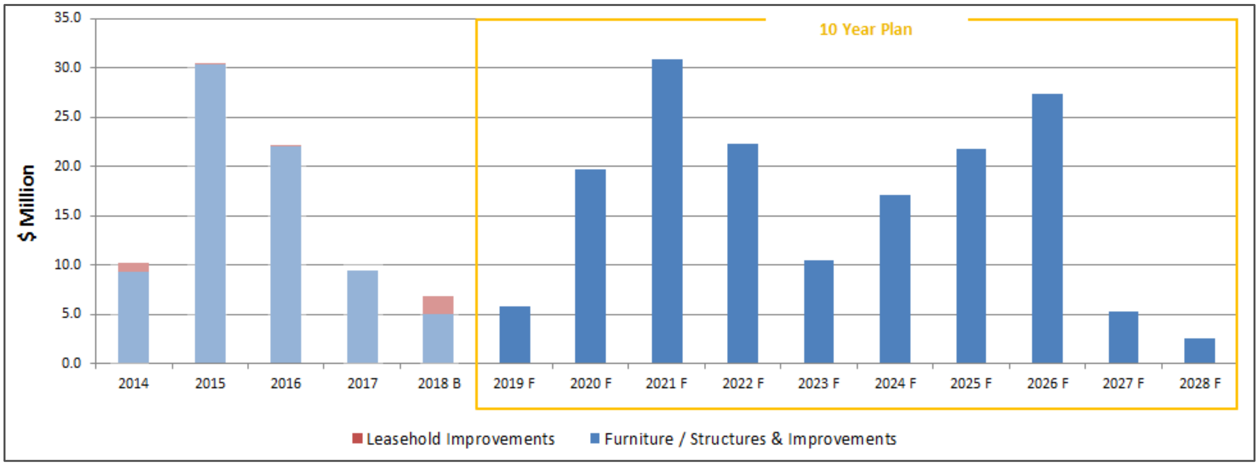


Figure 6.2-9: Maintenance Capital over Time for REWS

The historical annual spend for the asset class from 2014 to 2018 ranged from $7M to $30M. Similarly, the annual asset class spend for years 2019 to 2028 is expected to range from $3M to $31M. With an understanding of the condition of each work site, fluctuations in the spend profile are driven by the need to resolve physical and functional obsolescence of varying magnitudes at these locations.

Refer to **Section 5.6** for further details on the Real Estate and Workplace Services asset class.

6.2.2.6 Fleet and Equipment

The historical and projected 10-year spend profile for the Fleet and Equipment asset class is presented in **Figure 6.2-9**.

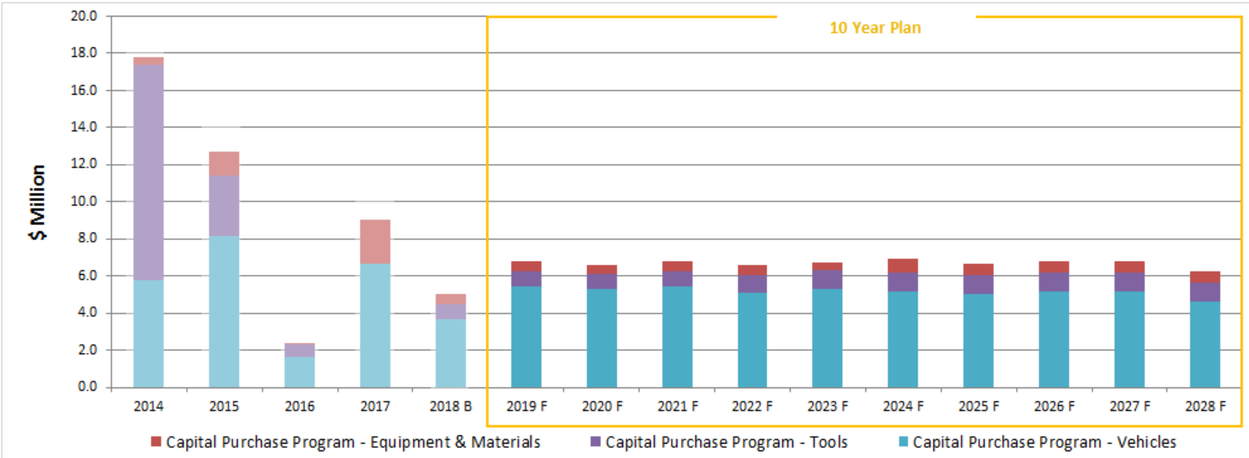


Figure 6.2-10: Maintenance Capital over Time for Fleet and Equipment

The historical annual spend for Fleet and Equipment from 2014 to 2018 has ranged from $2.3M to $17.8M. With an improved understanding of life cycle management strategies for this asset class, the projected 10-year spend profile differs from historical amounts and addresses long-term life cycle management strategies, at an average spend of $6.7M over 10 years. Variances in historical spending are a result of one-time capital expenditures to respond to business needs.

Refer to **Section 5.7** for further details on the Fleet and Equipment asset class.

6.2.2.7 Technology and Information Services (TIS)

On average, EGD has spent $24M annually on maintenance capital for the TIS asset class. The historical and projected 10-year spend profile is presented in **Figure 6.2-10**. The total capital spend for the TIS asset class is forecasted to be $40M in 2019 and on average to be $22M from 2020 to 2028.

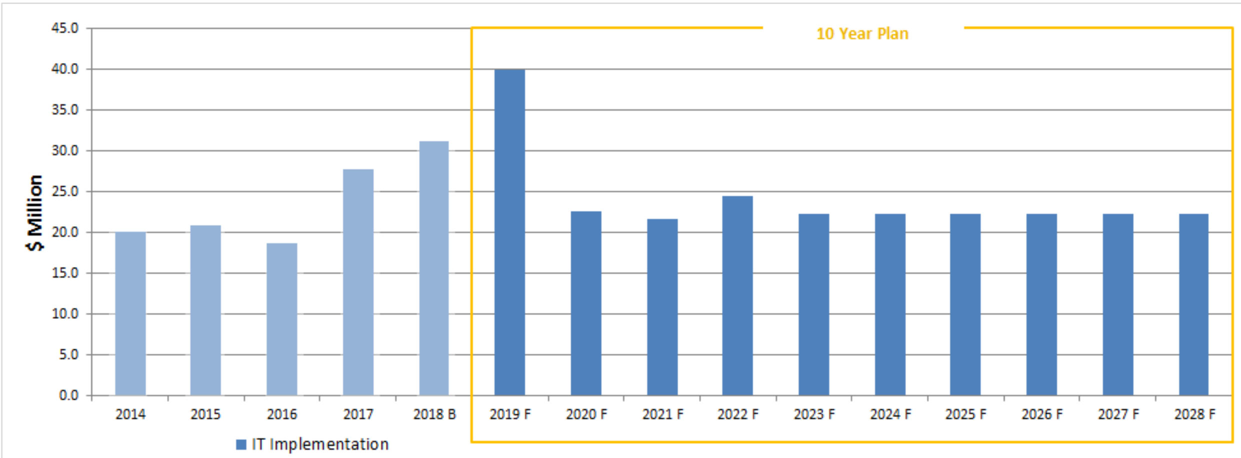


Figure 6.2-11: Maintenance Capital over Time for TIS

The TIS spend profile addresses system upgrades and replacements, large strategic initiatives, general business support, and ongoing system maintenance. Minor fluctuations in the profile are the result of increased spend to replace or upgrade systems according to their life cycle strategy. A significant increase in spend from 2018 to 2019 is due to large strategic initiatives: Customer Experience Transformation and CIS Hardware Replacement.

Refer to **Section 5.8** for further details on the Technology and Information Services asset class.

6.2.2.8 Business Development

The historical and projected 10-year spend profile for the Business Development asset class is presented in **Figure 6.2-12**.

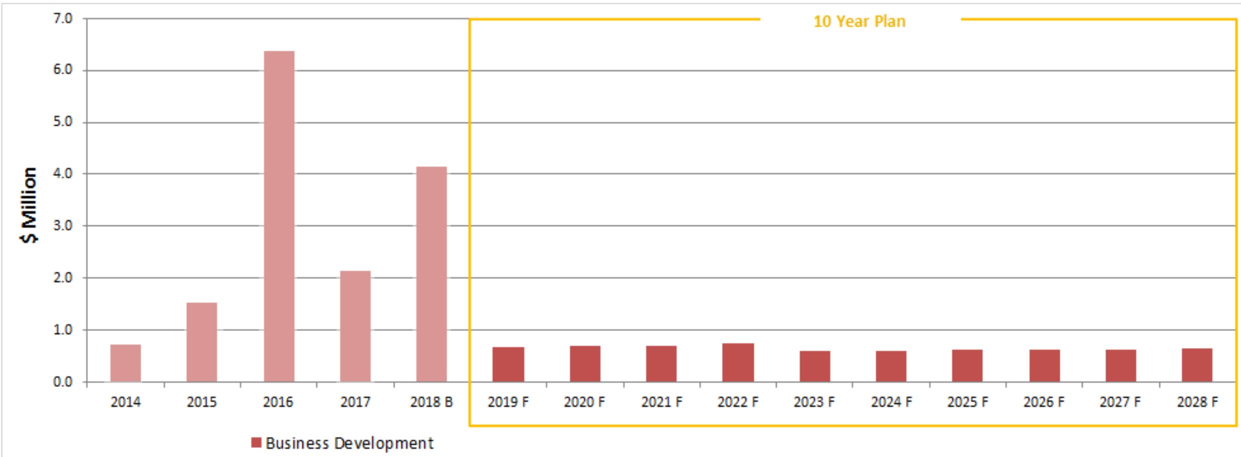


Figure 6.2-12: Maintenance Capital over Time for Business Development

Historical actual spend for NGV tracked under maintenance capital includes both growth and maintenance, ranging from $700K to $6.4M. The average annual Business Development maintenance capital from 2019 to 2028 is $700K and supports maintaining and upgrading existing NGV stations.

Refer to **Section 5.9** for further details on the Business Development asset class.

6.3 PROJECTS UNDER DEVELOPMENT

Although outlined in **Section 5** as assets requiring attention and further investigation, the following projects are not included in the 10-year portfolio of spend as their solution scopes are still under development:

- **Corunna Renewal**: Solution development for the renewal of the Corunna station for the Storage asset class is currently underway. The results from the proposed FEED study expected in 2019 may have the potential to accelerate this project.
- **Crowland Renewal**: Solution development for the renewal of the Crowland station for the Storage asset class is currently underway.
- **NGT Rental Compressors – Transit**: The addition of transit NGT customers, pending final contract completion.
- **NPS 20 Lake Shore KOL Replacement – Parliament to Bathurst**: The replacement of the KOL pipeline pending investigative results and confirmation of solution scope.
- **Pipe Reinforcements**: Scope and timing are under development for the Rideau reinforcement and the larger portions of the York Region reinforcement.

For visibility, **Table 6.3-1** presents the potential capital range and estimated timing for the solution currently under development. As these solutions are confirmed, they will be incorporated into EGD's 10-year plan.

Table 6.3-1: Capital Range and Timing for Projects under Development

		Estimate/Range of Required Capital	In Service Year(s)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Storage	Corunna Renewal	\$90M - \$150M	2022										
	Crowland Renewal	\$10M - \$15M	2021										
Business Development	NGT Rental Compressors - Transit	\$10M - \$40M	2022										
Pipe	NPS 20 Lake Shore KOL Replacement - Parliament to Bathurst	\$65 - \$150M	2026										
	Rideau Reinforcement	~\$55M	2023										
	York Region Reinforcement	~\$60M	2022 | 2026										

6.4 ASSUMPTIONS

The 10-year capital plan is based on the best available information at the time of completion. Key assumptions, as detailed in the tables below, provide a basis for interpretations.

Table 6.4-1: Assumptions for All Categories

ASSUMPTION	BASIS FOR ASSUMPTION
Optimization results are based on available information as of September 2018.	Based on EGD's Portfolio Optimization process, the portfolio of spend is determined through the completion of PP-AMP leveling and subsequent reviews.
Future costs are valued at 2018 Present Value.	Current practice forecasts projects based on 2018 rates. An annual inflation factor of 1.73% was applied to programs with defined scope/unit rates (such as meter purchases, customer growth, and service relays).
All cost estimates are based on available information as of August 2018.	Using EGD's Value-Based Asset Management Model, these requirements will be reviewed and revised as required.
All Risk Assessments are based on risk models and methodology as of August 2018.	Using EGD's Value-Based Asset Management Model, the Risk Management Framework will be reviewed and revised as required.
Projects in flight that span over multiple years must continue until complete.	Once a project is in progress it is inefficient and costly to terminate.
Capital overhead costs are not included in the Asset Management Plan.	The following direct costs are incremental to the capital requirements outlined in this plan: Direct Labour Costs, Interest During Construction, Administrative and General, and Extended Alliance (EA) Fixed Overheads.
Historical Actual Costs are valued at years' actual value.	Historical values are not adjusted to be expressed in present value.

Table 6.4-2: Renewal Assumptions

<table>
<tr><th>ASSUMPTION</th><th>BASIS FOR ASSUMPTION</th></tr>
<tr><td>Asset health provides a reasonable representation for asset condition and remaining asset life for forecasting purposes.</td><td rowspan="2">Reliability engineering is used to understand asset health. Based on projected life cycles, consequences of failure, tacit knowledge, and asset data, risk is quantified. Renewal projects are planned to reduce this risk to the lowest practicable level.</td></tr>
<tr><td>Optimization of renewal projects produces a forecast that maintains an acceptable level of risk to the organization.</td></tr>
</table>

Table 6.4-3: Customer Growth Assumptions

ASSUMPTION	BASIS FOR ASSUMPTION
Customer growth is forecasted using historical trends and economic projections for the planning period.	The Customer Growth Forecast considers new housing starts, meetings with builders and developers, municipal growth forecasts, general economic indicators, and projections provided by specialized external consultants to combine localized trends with macro-economic factors.
Load forecasting is based on current understanding of temperature inputs and estimated customer consumptions.	The company is evaluating the scope of its Carbon Strategy and subsequent impact on customer growth forecasts. Various technologies (such as smart thermostats) and energy efficiency programs (such as DSM) are being assessed to determine the potential impact on peak hour demand in the ongoing IRP study as directed through *EB-2015-0049*. The potential impact to peak hour demand and customer growth forecasts has not been incorporated in this Asset Management Plan due to the current uncertainty. Any outcomes resulting from the IRP study and advancements in the data collection and resultant strategies will be factored into future Asset Management Plans.

Table 6.4-4: Solution Planning Assumptions

ASSUMPTION	BASIS FOR ASSUMPTION
Budgeting and forecast is determined through the solution planning process.	Estimates are determined considering region and work type to accurately forecast. Appropriate project planning processes are followed.

7 Appendix

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Appendix 7.1 – Summary of Acronyms

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Acronyms List

Acronym	Meaning
ACD	Asset Class Director
ACM	Asset Class Manager
ADKAR	Awareness, Desire, Knowledge, Ability, and Reinforcement
AGA	American Gas Association
AI	Adequacy Index
AMO	Asset Management Optimization
APU	Auxiliary Power Unit
AUT	Automated Ultrasonic
BDDM	Business Development Data Mart
CCAP	Climate Change Action Plan
CEPA	Canadian Energy Pipeline Association
CGA	Canadian Gas Association
CIA	Change Impact Assessment
CIAC	Contribution In Aid of Construction
CIS	Customer Information System
CMHC	Canadian Mortgage and Housing Corporation
CMHC	Canada Mortgage and Housing Corporation
CNG	Compressed Natural Gas
CoF	Consequence of Failure
COMMS	Capital and Operations & Maintenance Management
CP	Cathodic Protection
CS&C	Customer Safety and Compliance
CSAT	Customer Satisfaction
CSI	Customer Satisfaction Index
DRS	Disaster Recovery Site
DSA	Designated Storage Area
DSM	Demand Side Management
ECCC	Environment and Climate Change Canada
EGD	Enbridge Gas Distribution
eGIS	Geographic Information System
EMV	Emergency Shutoff Valve
EnCore	Energy Cost Reporting
EnMar	Enbridge Meter and Reporting
EQMT	Engineering Quality Management
ERR	External Regulator Room
ESA	Electrical Safety Authority
ESD	Emergency Shutdown
ESV	Emergency Shut-off Valve
ETL	Extract, Transform, Load
FBA	Finance Business Analysis
FCI	Facility Condition Index
FEED	Front-End Engineering Design

Acronym	Meaning
FIMP	Facilities Integrity Management Program
GAC	Gas Aftercooler
GHG	Greenhouse Gas
GIS	Geographical Information System
GPS	Global Positioning System
GSTS	Gas Storage and Transmission System
GTA	Greater Toronto Area
GTI	Gas Technology Institute
HAZOP	Hazard and Operability Study
HCA	High Consequence Areas
HCF	High Cycle Fatigue
HMI	Human Machine Interface
HP	High Pressure
HVAC	Heating Ventilation Air Conditioning
I&E	Instrumentation and Electrical
IA	Internal Audit
IDC	Industrial Data Centre
IESO	Independent Electricity System Operator
ILI	In-line Inspection
IMP	Integrity Management Program
IMS	Integrated Management System
IP	Intermediate Pressure
IRP	Integrated Resource Planning
ISO	International Organization for Standardization
IT	Information Technology
IVR	Interactive Voice Response
JUT	Joint Utility Trench
JWC	Jacket Water Cooler
KPI	Key Performance Indicator
LAN	Local Area Network
LAN	Local Area Network
LDIW	Low Ductile Inner Wall
LRROI	Lifetime Risk Return on Investment
LSMS	Leak Survey Management System
LTC	Leave to Construct
LTEP	Long Term Energy Plan
LUF	Lost and Unaccounted For Gas
MAADs	Mergers, Acquisitions, Amalgamations and Divestitures
MCF	Mean Cumulative Function
MCF (SAP)	Multi-Channel Foundation
MOC	Management of Change
MOECC	Ministry of the Environment and Climate Change
MOP	Method of Procedure
MTBF	Mean Time Between Failure

Acronym	Meaning
MVRS	Meter Reading System
MXGI	Government Inspection Meter Exchange
NDT	Non-destructive Test
NGEIR	Natural Gas Electricity Interface Review
NGT	Natural Gas for Transportation
NHPP	Non-Homogeneous Poisson Process
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OPCO	Over-pressure Cut-offs
OQ	Operator Classification
OTD	Operations Technology Development
PHA	Process Hazard Analysis
PI	Profitability Index
PIR	Potential Impact Radius
PIT	Pressure Indicating Transmitters
PLC	Programmable Logic Controller
PoF	Probability of Failure
PP-AMP	PowerPlan Asset Management Planning
PPE	Personal Protective Equipment
PRIM	Pipeline Risk and Integrity Management
PSV	Pressure Relief Valve
QRA	Quantitative Risk Assessments
RAVE	Revenue Analysis and Volume Estimation
RCR	Records Correction Request
REWS	Real Estate & Workplace Services
RPP	Rolling Project Portfolio
RTU	Remote Telemetry Unit
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SCG	Slow Crack Growth
SCHT	Chatham D Compressor Station
SCOR	Corunna Compressor Station
SCRW	Crowland Compressor Station
SDIMP	Storage Downhole Integrity Management Program
SES	System Expansion Surcharge
SMA	Subject Matter Advisors
SMOC	South Merivale Operations Centre
SMYS	Specified Minimum Yield Strength
SRC	Safety and Reliability Committee
SSOM	Sombra Compressor Station
TIMP	Transmission Integrity Management Program
TIS	Technology and Information Services
TOC	Technology and Operations Centre
TSSA	Technical Standards & Safety Authority

Acronym	Meaning
UGL	Union Gas Limited
UPS	Uninterruptible Power Supply
URICA	Unbundled Rate Compliance
USP	Utility System Plan
VFD	Variable Frequency Drives
VRA	Vehicle Refueling Appliance
WAMS	Work Asset Management System
XHP	Extra High Pressure

Appendix 7.2-1 – Customer Growth Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Customer Growth **Business Case ID:**3402
Estimate Class: Class 5

Project Information

Name: Area 10 - Apartment Ensuite - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Apartment Ensuite - New Construction

Project Type: Header Install - Vertical

Issue/Concern: Vertical Subdivision refers to a multiple unit residential building where each suite is individually metered.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Included in the commercial Sector are Apartment and Vertical subdivisions. An apartment customer is a multi-residential dwelling containing more than six units that is bulk-metered. A Vertical subdivision is a multiple unit residential building where each suite is individually metered. Collectively, the commercial sector consists of new construction and replacement markets, accounting for over 7% of the customer additions forecast. The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,584,946	$21,368,746	109

Asset Class: Customer Growth **Business Case ID:**3402
Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$1,080,730	$1,136,738	$2,321,778	$2,408,584	$2,459,123	$2,433,377	$2,431,158	$2,399,092	$2,377,783	$2,320,383	$21,368,746
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,080,730	$1,136,738	$2,321,778	$2,408,584	$2,459,123	$2,433,377	$2,431,158	$2,399,092	$2,377,783	$2,320,383	$21,368,746
Retirement Cost											
Total Project Cost	$1,080,730	$1,136,738	$2,321,778	$2,408,584	$2,459,123	$2,433,377	$2,431,158	$2,399,092	$2,377,783	$2,320,383	$21,368,746

Asset Class: Customer Growth **Business Case ID:**3402

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3402

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3406
Estimate Class: Class 5

Project Information

Name: Area 10 - Commercial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - New Construction

Project Type: Other

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,686,562	$51,729,994	37

POWERPLAN AMP

Asset Class: Customer Growth

Business Case ID:3406

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$2,296,597	$2,415,616	$5,700,134	$5,913,249	$6,037,326	$5,974,117	$5,968,670	$5,889,946	$5,837,630	$5,696,709	$51,729,994
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,296,597	$2,415,616	$5,700,134	$5,913,249	$6,037,326	$5,974,117	$5,968,670	$5,889,946	$5,837,630	$5,696,709	$51,729,994
Retirement Cost											
Total Project Cost	$2,296,597	$2,415,616	$5,700,134	$5,913,249	$6,037,326	$5,974,117	$5,968,670	$5,889,946	$5,837,630	$5,696,709	$51,729,994

Asset Class: Customer Growth

Business Case ID:3406

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3406

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10125
Estimate Class: Class 5

Project Information

Name: Area 10 - Apartment Ensuite - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Apartment Ensuite - New Construction

Project Type: Header Install - Vertical

Issue/Concern: Vertical Subdivision refers to a multiple unit residential building where each suite is individually metered.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements: - Installation costs related to mains, services, and meters

- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Included in the commercial sector are Apartment and Vertical subdivisions. An apartment customer is a multi-residential dwelling containing more than six units that is bulk-metered. A Vertical subdivision is a multiple unit residential building where each suite is individually metered. Collectively, the commercial sector consists of new construction and replacement markets, accounting for over 7% of the customer additions forecast. The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include: - The size and type of material required

- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	1,465,007	$4,602,696	466

Asset Class: Customer Growth **Business Case ID:**10125
Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$2,300,030	$2,302,666	$0	$0	$0	$0	$0	$0	$0	$0	$4,602,696
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,300,030	$2,302,666	$0	$0	$0	$0	$0	$0	$0	$0	$4,602,696
Retirement Cost											
Total Project Cost	$2,300,030	$2,302,666	$0	$0	$0	$0	$0	$0	$0	$0	$4,602,696

Asset Class: Customer Growth **Business Case ID:**10125

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10125

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10129
Estimate Class: Class 5

Project Information

Name: Area 10 - Commercial - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Commercial - New Construction

Project Type: Other

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 10 - Commercial - New Construction Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,159,844	$11,299,955	116

Asset Class: Customer Growth

Estimate Class: Class 5

Business Case ID:10129

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$5,646,742	$5,653,213	$0	$0	$0	$0	$0	$0	$0	$0	$11,299,955
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,646,742	$5,653,213	$0	$0	$0	$0	$0	$0	$0	$0	$11,299,955
Retirement Cost											
Total Project Cost	$5,646,742	$5,653,213	$0	$0	$0	$0	$0	$0	$0	$0	$11,299,955

Asset Class: Customer Growth

Business Case ID:10129

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10129

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3726
Estimate Class: Class 5

Project Information

Name: Area 20 - Commercial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,893,367	$22,819,558	143
Option 2		3,204,115	0	0

Asset Class: Customer Growth **Business Case ID:**3726

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$2,383,320	$2,506,834	$2,173,646	$2,254,914	$2,302,228	$2,278,125	$2,276,047	$2,246,027	$2,226,078	$2,172,340	$22,819,558
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,383,320	$2,506,834	$2,173,646	$2,254,914	$2,302,228	$2,278,125	$2,276,047	$2,246,027	$2,226,078	$2,172,340	$22,819,558
Retirement Cost											
Total Project Cost	$2,383,320	$2,506,834	$2,173,646	$2,254,914	$2,302,228	$2,278,125	$2,276,047	$2,246,027	$2,226,078	$2,172,340	$22,819,558

Asset Class: Customer Growth **Business Case ID:**3726

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:** 3726

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10146
Estimate Class: Class 5

Project Information

Name: Area 20 - Commercial - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 20 - Commercial - New Construction The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,220,905	$4,309,039	581

Asset Class: Customer Growth

Business Case ID:10146

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$2,153,286	$2,155,753	$0	$0	$0	$0	$0	$0	$0	$0	$4,309,039
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,153,286	$2,155,753	$0	$0	$0	$0	$0	$0	$0	$0	$4,309,039
Retirement Cost											
Total Project Cost	$2,153,286	$2,155,753	$0	$0	$0	$0	$0	$0	$0	$0	$4,309,039

Asset Class: Customer Growth **Business Case ID:**10146

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10146

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3783
Estimate Class: Class 5

Project Information

Name: Area 20 - Commercial - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - Replacement

Project Type: Commercial

Issue/Concern: Commercial Replacement refers to a commercial replacement customer using a fuel other than natural gas for commercial business and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 20 - Commercial - Replacement The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	530,498	$5,540,047	108

Asset Class: Customer Growth **Business Case ID:**3783

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$538,169	$566,059	$537,770	$557,876	$569,582	$563,619	$563,105	$555,678	$550,742	$537,447	$5,540,047
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$538,169	$566,059	$537,770	$557,876	$569,582	$563,619	$563,105	$555,678	$550,742	$537,447	$5,540,047
Retirement Cost											
Total Project Cost	$538,169	$566,059	$537,770	$557,876	$569,582	$563,619	$563,105	$555,678	$550,742	$537,447	$5,540,047

Asset Class: Customer Growth **Business Case ID:**3783

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3783

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3731
Estimate Class: Class 5

Project Information

Name: Area 30 - Apartment Ensuite - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Apartment Ensuite - New Construction

Project Type: Header Install - Vertical

Issue/Concern: Vertical Subdivision refers to a multiple unit residential building where each suite is individually metered.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 30 - Apartment Ensuite - New Construction Included in the commercial Sector are Apartment and Vertical subdivisions. An apartment customer is a multi-residential dwelling containing more than six units that is bulk-metered. A Vertical subdivision is a multiple unit residential building where each suite is individually metered. Collectively, the commercial sector consists of new construction and replacement markets, accounting for over 7% of the customer additions forecast. The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include: - The size and type of material required

- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	567,623	$5,341,194	156

Asset Class: Customer Growth **Business Case ID:**3731
Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$157,278	$165,428	$608,409	$631,156	$644,400	$637,653	$637,072	$628,669	$623,085	$608,044	$5,341,194
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$157,278	$165,428	$608,409	$631,156	$644,400	$637,653	$637,072	$628,669	$623,085	$608,044	$5,341,194
Retirement Cost											
Total Project Cost	$157,278	$165,428	$608,409	$631,156	$644,400	$637,653	$637,072	$628,669	$623,085	$608,044	$5,341,194

Asset Class: Customer Growth **Business Case ID:**3731

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3731

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3735
Estimate Class: Class 5

Project Information

Name: Area 30 - Commercial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main - Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,162,829	$38,662,802	63

Asset Class: Customer Growth

Business Case ID:3735

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$4,481,583	$4,713,837	$3,572,436	$3,706,002	$3,783,764	$3,744,149	$3,740,735	$3,691,397	$3,658,609	$3,570,290	$38,662,802
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,481,583	$4,713,837	$3,572,436	$3,706,002	$3,783,764	$3,744,149	$3,740,735	$3,691,397	$3,658,609	$3,570,290	$38,662,802
Retirement Cost											
Total Project Cost	$4,481,583	$4,713,837	$3,572,436	$3,706,002	$3,783,764	$3,744,149	$3,740,735	$3,691,397	$3,658,609	$3,570,290	$38,662,802

Asset Class: Customer Growth **Business Case ID:**3735

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3735

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10155
Estimate Class: Class 5

Project Information

Name: Area 30 - Commercial - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 30 - Commercial - New Construction The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,666,582	$7,082,003	265

Asset Class: Customer Growth **Business Case ID:**10155
Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$3,538,974	$3,543,029	$0	$0	$0	$0	$0	$0	$0	$0	$7,082,003
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,538,974	$3,543,029	$0	$0	$0	$0	$0	$0	$0	$0	$7,082,003
Retirement Cost											
Total Project Cost	$3,538,974	$3,543,029	$0	$0	$0	$0	$0	$0	$0	$0	$7,082,003

Asset Class: Customer Growth **Business Case ID:**10155

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10155

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3744
Estimate Class: Class 5

Project Information

Name: Area 40 - Commercial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,098,272	$13,253,215	178

Asset Class: Customer Growth

Business Case ID:3744

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$1,805,574	$1,899,146	$1,157,598	$1,200,878	$1,226,076	$1,213,240	$1,212,133	$1,196,146	$1,185,521	$1,156,903	$13,253,215
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,805,574	$1,899,146	$1,157,598	$1,200,878	$1,226,076	$1,213,240	$1,212,133	$1,196,146	$1,185,521	$1,156,903	$13,253,215
Retirement Cost											
Total Project Cost	$1,805,574	$1,899,146	$1,157,598	$1,200,878	$1,226,076	$1,213,240	$1,212,133	$1,196,146	$1,185,521	$1,156,903	$13,253,215

Asset Class: Customer Growth **Business Case ID:**3744

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3744

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10164
Estimate Class: Class 5

Project Information

Name: Area 40 - Commercial - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 40 - Commercial - New Construction The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	1,622,587	$2,294,824	797

Asset Class: Customer Growth **Business Case ID:**10164

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$1,146,755	$1,148,069	$0	$0	$0	$0	$0	$0	$0	$0	$2,294,824
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,146,755	$1,148,069	$0	$0	$0	$0	$0	$0	$0	$0	$2,294,824
Retirement Cost											
Total Project Cost	$1,146,755	$1,148,069	$0	$0	$0	$0	$0	$0	$0	$0	$2,294,824

Asset Class: Customer Growth **Business Case ID:**10164

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10164

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3753
Estimate Class: Class 5

Project Information

Name: Area 50 - Commercial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,243,440	$8,350,316	168

Asset Class: Customer Growth

Business Case ID:3753

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$1,170,746	$1,231,419	$721,116	$748,077	$763,773	$755,777	$755,088	$745,128	$738,510	$720,682	$8,350,316
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,170,746	$1,231,419	$721,116	$748,077	$763,773	$755,777	$755,088	$745,128	$738,510	$720,682	$8,350,316
Retirement Cost											
Total Project Cost	$1,170,746	$1,231,419	$721,116	$748,077	$763,773	$755,777	$755,088	$745,128	$738,510	$720,682	$8,350,316

Asset Class: Customer Growth **Business Case ID:**3753

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3753

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3761
Estimate Class: Class 5

Project Information

Name: Area 60 - Commercial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,564,968	$41,631,339	42

Asset Class: Customer Growth **Business Case ID:**3761
Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$2,578,591	$2,712,224	$4,405,692	$4,570,411	$4,666,311	$4,617,456	$4,613,246	$4,552,399	$4,511,964	$4,403,045	$41,631,339
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,578,591	$2,712,224	$4,405,692	$4,570,411	$4,666,311	$4,617,456	$4,613,246	$4,552,399	$4,511,964	$4,403,045	$41,631,339
Retirement Cost											
Total Project Cost	$2,578,591	$2,712,224	$4,405,692	$4,570,411	$4,666,311	$4,617,456	$4,613,246	$4,552,399	$4,511,964	$4,403,045	$41,631,339

Asset Class: Customer Growth **Business Case ID:**3761

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3761

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10181
Estimate Class: Class 5

Project Information

Name: Area 60 - Commercial - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 60 - Commercial - New Construction The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,194,038	$8,733,851	154

Asset Class: Customer Growth

Business Case ID:10181

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$4,364,425	$4,369,426	$0	$0	$0	$0	$0	$0	$0	$0	$8,733,851
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,364,425	$4,369,426	$0	$0	$0	$0	$0	$0	$0	$0	$8,733,851
Retirement Cost											
Total Project Cost	$4,364,425	$4,369,426	$0	$0	$0	$0	$0	$0	$0	$0	$8,733,851

Asset Class: Customer Growth **Business Case ID:**10181

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10181

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3769
Estimate Class: Class 5

Project Information

Name: Area 80 - Commercial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - New Construction

Project Type: Commercial

Issue/Concern: Commercial New Construction refers to a customer intending to run a commercial business in a newly-constructed building and intending to using natural gas to meet energy needs
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,217,019	$9,251,893	148

Asset Class: Customer Growth **Business Case ID:**3769
Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$1,010,624	$1,062,999	$870,247	$902,784	$921,727	$912,077	$911,245	$899,226	$891,239	$869,724	$9,251,893
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,010,624	$1,062,999	$870,247	$902,784	$921,727	$912,077	$911,245	$899,226	$891,239	$869,724	$9,251,893
Retirement Cost											
Total Project Cost	$1,010,624	$1,062,999	$870,247	$902,784	$921,727	$912,077	$911,245	$899,226	$891,239	$869,724	$9,251,893

Asset Class: Customer Growth **Business Case ID:**3769

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3769

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3822
Estimate Class: Class 5

Project Information

Name: Area 80 - Commercial - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Commercial - Replacement

Project Type: Commercial

Issue/Concern: Commercial Replacement refers to a commercial replacement customer using a fuel other than natural gas for commercial business and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Commercial Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new commercial or fuel conversion customers within the EGD franchise area. The number of commercial customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area which is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	186,025	$6,837,167	31

Asset Class: Customer Growth **Business Case ID:**3822
Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$147,000	$154,618	$792,328	$821,952	$839,198	$830,412	$829,655	$818,712	$811,440	$791,852	$6,837,167
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$147,000	$154,618	$792,328	$821,952	$839,198	$830,412	$829,655	$818,712	$811,440	$791,852	$6,837,167
Retirement Cost											
Total Project Cost	$147,000	$154,618	$792,328	$821,952	$839,198	$830,412	$829,655	$818,712	$811,440	$791,852	$6,837,167

Asset Class: Customer Growth **Business Case ID:**3822

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3822

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3727
Estimate Class: Class 5

Project Information

Name: Area 20 - Industrial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Industrial - New Construction

Project Type: Main Install - Commercial/Industrial

Issue/Concern: Industrial New Construction refers to a customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 20 - Industrial - New Construction The Industrial Sector Program scope includes activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new industrial or fuel conversion customers within the EGD franchise area. The number of industrial customer additions is determined through an annual planning process using a number of sources, including economic factors and indicators from reliable third-party data sources. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,491,837	0

Asset Class: Customer Growth **Business Case ID:**3727

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$10,416	$10,955	$299,503	$310,701	$317,221	$313,899	$313,613	$309,477	$306,728	$299,324	$2,491,837
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,416	$10,955	$299,503	$310,701	$317,221	$313,899	$313,613	$309,477	$306,728	$299,324	$2,491,837
Retirement Cost											
Total Project Cost	$10,416	$10,955	$299,503	$310,701	$317,221	$313,899	$313,613	$309,477	$306,728	$299,324	$2,491,837

Asset Class: Customer Growth **Business Case ID:**3727

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3727

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3762
Estimate Class: Class 5

Project Information

Name: Area 60 - Industrial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Industrial - New Construction

Project Type: Main Install - Commercial/Industrial

Issue/Concern: Industrial New Construction refers to a customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 60 - Industrial - New Construction Scope of Work: The Industrial Sector Program scope includes activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new industrial or fuel conversion customers within the EGD franchise area. The number of industrial customer additions is determined through an annual planning process using a number of sources, including economic factors and indicators from reliable third-party data sources. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$19,912,291	0

Asset Class: Customer Growth

Business Case ID: 3762

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$7,136	$7,506	$2,412,263	$2,502,452	$2,554,961	$2,528,211	$2,525,906	$2,492,591	$2,470,451	$2,410,814	$19,912,291
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,136	$7,506	$2,412,263	$2,502,452	$2,554,961	$2,528,211	$2,525,906	$2,492,591	$2,470,451	$2,410,814	$19,912,291
Retirement Cost											
Total Project Cost	$7,136	$7,506	$2,412,263	$2,502,452	$2,554,961	$2,528,211	$2,525,906	$2,492,591	$2,470,451	$2,410,814	$19,912,291

Asset Class: Customer Growth **Business Case ID:**3762

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3762

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10182

Estimate Class: Class 5

Project Information

Name: Area 60 - Industrial - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Industrial - New Construction

Project Type: Main Install - Commercial/Industrial

Issue/Concern: Industrial New Construction refers to a customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 60 - Industrial - New Construction Area 60 - Industrial - New Construction The Industrial Sector Program scope includes activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new industrial or fuel conversion customers within the EGD franchise area. The number of industrial customer additions is determined through an annual planning process using a number of sources, including economic factors and indicators from reliable third-party data sources. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include: - The size and type of material required

- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main

- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$4,782,074	0

Asset Class: Customer Growth **Business Case ID:**10182

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$2,389,668	$2,392,406	$0	$0	$0	$0	$0	$0	$0	$0	$4,782,074
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,389,668	$2,392,406	$0	$0	$0	$0	$0	$0	$0	$0	$4,782,074
Retirement Cost											
Total Project Cost	$2,389,668	$2,392,406	$0	$0	$0	$0	$0	$0	$0	$0	$4,782,074

Asset Class: Customer Growth **Business Case ID:**10182

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10182

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3770
Estimate Class: Class 5

Project Information

Name: Area 80 - Industrial - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Industrial - New Construction

Project Type: Main Install - Commercial/Industrial

Issue/Concern: Industrial New Construction refers to a customer intending to run an industrial manufacturing business in a newly-built facility and intending to use natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 80 - Industrial - New Construction The Industrial Sector Program scope includes activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new industrial or fuel conversion customers within the EGD franchise area. The number of industrial customer additions is determined through an annual planning process using a number of sources, including economic factors and indicators from reliable third-party data sources. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,198,761	0

Asset Class: Customer Growth

Estimate Class: Class 5

Business Case ID:3770

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$6,777	$7,128	$871,046	$903,612	$922,573	$912,914	$912,081	$900,051	$892,057	$870,522	$7,198,761
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,777	$7,128	$871,046	$903,612	$922,573	$912,914	$912,081	$900,051	$892,057	$870,522	$7,198,761
Retirement Cost											
Total Project Cost	$6,777	$7,128	$871,046	$903,612	$922,573	$912,914	$912,081	$900,051	$892,057	$870,522	$7,198,761

Asset Class: Customer Growth **Business Case ID:**3770

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3770

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth

Business Case ID:3408

Estimate Class: Class 5

Project Information

Name: Area 10 - Residential - Replacement

Type: Enbridge Program

Start Year: 2017

Asset Program: Residential - Replacement

Project Type: Other

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 10 - Residential - Replacement The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	1,197,150	$72,199,402	24

Asset Class: Customer Growth **Business Case ID:**3408

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$7,536,716	$8,137,665	$6,852,731	$7,108,939	$7,258,105	$7,182,115	$7,175,566	$7,080,924	$7,018,029	$6,848,613	$72,199,402
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,536,716	$8,137,665	$6,852,731	$7,108,939	$7,258,105	$7,182,115	$7,175,566	$7,080,924	$7,018,029	$6,848,613	$72,199,402
Retirement Cost											
Total Project Cost	$7,536,716	$8,137,665	$6,852,731	$7,108,939	$7,258,105	$7,182,115	$7,175,566	$7,080,924	$7,018,029	$6,848,613	$72,199,402

Asset Class: Customer Growth **Business Case ID:**3408

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3408

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3700
Estimate Class: Class 5

Project Information

Name: Area 10 - Residential - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - New Construction

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,536,019	$7,728,535	291

Asset Class: Customer Growth

Business Case ID:3700

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$339,565	$357,163	$852,491	$884,364	$902,920	$893,467	$892,652	$880,879	$873,054	$851,979	$7,728,535
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$339,565	$357,163	$852,491	$884,364	$902,920	$893,467	$892,652	$880,879	$873,054	$851,979	$7,728,535
Retirement Cost											
Total Project Cost	$339,565	$357,163	$852,491	$884,364	$902,920	$893,467	$892,652	$880,879	$873,054	$851,979	$7,728,535

Asset Class: Customer Growth **Business Case ID:**3700

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3700

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth

Business Case ID:10131

Estimate Class: Class 5

Project Information

Name: Area 10 - Residential - Replacement 2027+

Type: Enbridge Program

Start Year: 2027

Asset Program: Residential - Replacement

Project Type: Other

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 10 - Residential - Replacement Area 10 - Residential - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	999,208	$13,584,865	108

Asset Class: Customer Growth **Business Case ID:**10131
Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$6,788,543	$6,796,322	$0	$0	$0	$0	$0	$0	$0	$0	$13,584,865
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,788,543	$6,796,322	$0	$0	$0	$0	$0	$0	$0	$0	$13,584,865
Retirement Cost											
Total Project Cost	$6,788,543	$6,796,322	$0	$0	$0	$0	$0	$0	$0	$0	$13,584,865

Asset Class: Customer Growth **Business Case ID:**10131

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10131

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3729
Estimate Class: Class 5

Project Information

Name: Area 20 - Residential - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	9,728,340	$63,127,306	226

Asset Class: Customer Growth **Business Case ID:**3729

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$7,318,382	$7,908,016	$5,807,199	$6,024,317	$6,150,724	$6,086,328	$6,080,778	$6,000,576	$5,947,277	$5,803,709	$63,127,306
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,318,382	$7,908,016	$5,807,199	$6,024,317	$6,150,724	$6,086,328	$6,080,778	$6,000,576	$5,947,277	$5,803,709	$63,127,306
Retirement Cost											
Total Project Cost	$7,318,382	$7,908,016	$5,807,199	$6,024,317	$6,150,724	$6,086,328	$6,080,778	$6,000,576	$5,947,277	$5,803,709	$63,127,306

Asset Class: Customer Growth **Business Case ID:**3729

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3729

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth
Estimate Class: Class 5

Business Case ID:10149

Project Information

Name: Area 20 - Residential - New Construction 2027+

Type: Enbridge Program

Start Year: 2027

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 20 - Residential - New Construction Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	8,814,524	$11,512,200	1,122

Asset Class: Customer Growth

Estimate Class: Class 5

Business Case ID:10149

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$5,752,804	$5,759,396	$0	$0	$0	$0	$0	$0	$0	$0	$11,512,200
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,752,804	$5,759,396	$0	$0	$0	$0	$0	$0	$0	$0	$11,512,200
Retirement Cost											
Total Project Cost	$5,752,804	$5,759,396	$0	$0	$0	$0	$0	$0	$0	$0	$11,512,200

Asset Class: Customer Growth **Business Case ID:**10149

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10149

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3730

Estimate Class: Class 5

Project Information

Name: Area 20 - Residential - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 20 - Residential - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	288,633	$10,372,461	41

Asset Class: Customer Growth **Business Case ID:**3730
Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$1,534,290	$1,613,804	$875,836	$908,581	$927,646	$917,934	$917,097	$905,001	$896,962	$875,310	$10,372,461
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,534,290	$1,613,804	$875,836	$908,581	$927,646	$917,934	$917,097	$905,001	$896,962	$875,310	$10,372,461
Retirement Cost											
Total Project Cost	$1,534,290	$1,613,804	$875,836	$908,581	$927,646	$917,934	$917,097	$905,001	$896,962	$875,310	$10,372,461

Asset Class: Customer Growth **Business Case ID:**3730

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3730

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3738

Estimate Class: Class 5

Project Information

Name: Area 30 - Residential - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing. Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	10,182,664	$107,952,704	138

Asset Class: Customer Growth

Business Case ID:3738

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$8,649,860	$8,308,497	$11,031,571	$11,444,016	$11,684,144	$11,561,815	$11,551,273	$11,398,917	$11,297,669	$11,024,942	$107,952,704
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$8,649,860	$8,308,497	$11,031,571	$11,444,016	$11,684,144	$11,561,815	$11,551,273	$11,398,917	$11,297,669	$11,024,942	$107,952,704
Retirement Cost											
Total Project Cost	$8,649,860	$8,308,497	$11,031,571	$11,444,016	$11,684,144	$11,561,815	$11,551,273	$11,398,917	$11,297,669	$11,024,942	$107,952,704

Asset Class: Customer Growth **Business Case ID:**3738

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3738

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3739
Estimate Class: Class 5

Project Information

Name: Area 30 - Residential - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 30 - Residential - Replacement. The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	434,701	$45,820,503	14

Asset Class: Customer Growth

Business Case ID:3739

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$4,867,094	$5,119,328	$4,344,294	$4,506,717	$4,601,281	$4,553,107	$4,548,956	$4,488,957	$4,449,085	$4,341,684	$45,820,503
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,867,094	$5,119,328	$4,344,294	$4,506,717	$4,601,281	$4,553,107	$4,548,956	$4,488,957	$4,449,085	$4,341,684	$45,820,503
Retirement Cost											
Total Project Cost	$4,867,094	$5,119,328	$4,344,294	$4,506,717	$4,601,281	$4,553,107	$4,548,956	$4,488,957	$4,449,085	$4,341,684	$45,820,503

Asset Class: Customer Growth **Business Case ID:**3739

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3739

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10158
Estimate Class: Class 5

Project Information

Name: Area 30 - Residential - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 30 - Residential - New Construction Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	9,258,283	$21,869,003	620

Asset Class: Customer Growth

Business Case ID:10158

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$10,928,240	$10,940,763	$0	$0	$0	$0	$0	$0	$0	$0	$21,869,003
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,928,240	$10,940,763	$0	$0	$0	$0	$0	$0	$0	$0	$21,869,003
Retirement Cost											
Total Project Cost	$10,928,240	$10,940,763	$0	$0	$0	$0	$0	$0	$0	$0	$21,869,003

Asset Class: Customer Growth **Business Case ID:**10158

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10158

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10159

Estimate Class: Class 5

Project Information

Name: Area 30 - Residential - Replacement 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 30 - Residential - Replacement Area 30 - Residential - Replacement The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	384,670	$8,612,135	65

Asset Class: Customer Growth

Estimate Class: Class 5

Business Case ID:10159

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$4,303,602	$4,308,533	$0	$0	$0	$0	$0	$0	$0	$0	$8,612,135
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,303,602	$4,308,533	$0	$0	$0	$0	$0	$0	$0	$0	$8,612,135
Retirement Cost											
Total Project Cost	$4,303,602	$4,308,533	$0	$0	$0	$0	$0	$0	$0	$0	$8,612,135

Asset Class: Customer Growth **Business Case ID:**10159

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10159

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3747

Estimate Class: Class 5

Project Information

Name: Area 40 - Residential - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees

-

- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	7,581,637	$44,856,235	248

Asset Class: Customer Growth

Business Case ID: 3747

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$2,658,446	$2,796,218	$4,776,794	$4,955,387	$5,059,365	$5,006,395	$5,001,830	$4,935,859	$4,892,017	$4,773,923	$44,856,235
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,658,446	$2,796,218	$4,776,794	$4,955,387	$5,059,365	$5,006,395	$5,001,830	$4,935,859	$4,892,017	$4,773,923	$44,856,235
Retirement Cost											
Total Project Cost	$2,658,446	$2,796,218	$4,776,794	$4,955,387	$5,059,365	$5,006,395	$5,001,830	$4,935,859	$4,892,017	$4,773,923	$44,856,235

Asset Class: Customer Growth **Business Case ID:**3747

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3747

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth
Business Case ID:3748
Estimate Class: Class 5

Project Information

Name: Area 40 - Residential - Replacement

Type: Enbridge Program
Start Year: 2017

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans:: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 40 - Residential - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,117,876	$51,184,744	32

Asset Class: Customer Growth

Business Case ID:3748

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$5,227,495	$5,498,406	$4,904,971	$5,088,356	$5,195,124	$5,140,733	$5,136,046	$5,068,304	$5,023,286	$4,902,023	$51,184,744
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,227,495	$5,498,406	$4,904,971	$5,088,356	$5,195,124	$5,140,733	$5,136,046	$5,068,304	$5,023,286	$4,902,023	$51,184,744
Retirement Cost											
Total Project Cost	$5,227,495	$5,498,406	$4,904,971	$5,088,356	$5,195,124	$5,140,733	$5,136,046	$5,068,304	$5,023,286	$4,902,023	$51,184,744

Asset Class: Customer Growth **Business Case ID:**3748

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3748

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10167
Estimate Class: Class 5

Project Information

Name: Area 40 - Residential - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 40 - Residential - New Construction The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	6,911,061	$9,469,523	1,069

Asset Class: Customer Growth

Business Case ID:10167

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$4,732,050	$4,737,473	$0	$0	$0	$0	$0	$0	$0	$0	$9,469,523
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,732,050	$4,737,473	$0	$0	$0	$0	$0	$0	$0	$0	$9,469,523
Retirement Cost											
Total Project Cost	$4,732,050	$4,737,473	$0	$0	$0	$0	$0	$0	$0	$0	$9,469,523

Asset Class: Customer Growth **Business Case ID:**10167

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10167

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10168
Estimate Class: Class 5

Project Information

Name: Area 40 - Residential - Replacement 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 40 - Residential - Replacement Area 40 - Residential - Replacement The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	932,004	$9,723,620	140

Asset Class: Customer Growth **Business Case ID:**10168

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$4,859,026	$4,864,594	$0	$0	$0	$0	$0	$0	$0	$0	$9,723,620
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,859,026	$4,864,594	$0	$0	$0	$0	$0	$0	$0	$0	$9,723,620
Retirement Cost											
Total Project Cost	$4,859,026	$4,864,594	$0	$0	$0	$0	$0	$0	$0	$0	$9,723,620

Asset Class: Customer Growth **Business Case ID:**10168

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10168

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth

Business Case ID:3756

Estimate Class: Class 5

Project Information

Name: Area 50 - Residential - New Construction

Type: Enbridge Program

Start Year: 2017

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	6,323,436	$56,472,348	164

Asset Class: Customer Growth

Estimate Class: Class 5

Business Case ID:3756

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$3,780,190	$3,976,096	$5,906,023	$6,126,836	$6,255,394	$6,189,902	$6,184,258	$6,102,690	$6,048,485	$5,902,474	$56,472,348
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,780,190	$3,976,096	$5,906,023	$6,126,836	$6,255,394	$6,189,902	$6,184,258	$6,102,690	$6,048,485	$5,902,474	$56,472,348
Retirement Cost											
Total Project Cost	$3,780,190	$3,976,096	$5,906,023	$6,126,836	$6,255,394	$6,189,902	$6,184,258	$6,102,690	$6,048,485	$5,902,474	$56,472,348

Asset Class: Customer Growth **Business Case ID:**3756

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3756

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3757
Estimate Class: Class 5

Project Information

Name: Area 50 - Residential - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 50 - Residential - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	832,771	$40,706,756	30

Asset Class: Customer Growth

Business Case ID:3757

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$5,303,794	$5,789,024	$3,590,204	$3,724,433	$3,802,582	$3,762,771	$3,759,340	$3,709,756	$3,676,805	$3,588,047	$40,706,756
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,303,794	$5,789,024	$3,590,204	$3,724,433	$3,802,582	$3,762,771	$3,759,340	$3,709,756	$3,676,805	$3,588,047	$40,706,756
Retirement Cost											
Total Project Cost	$5,303,794	$5,789,024	$3,590,204	$3,724,433	$3,802,582	$3,762,771	$3,759,340	$3,709,756	$3,676,805	$3,588,047	$40,706,756

Asset Class: Customer Growth **Business Case ID:**3757

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3757

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth

Business Case ID:10176

Estimate Class: Class 5

Project Information

Name: Area 50 - Residential - New Construction 2027+

Type: Enbridge Program

Start Year: 2027

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 50 - Residential - New Construction Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	5,740,299	$11,708,108	718

Asset Class: Customer Growth **Business Case ID:**10176
Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$5,850,702	$5,857,406	$0	$0	$0	$0	$0	$0	$0	$0	$11,708,108
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,850,702	$5,857,406	$0	$0	$0	$0	$0	$0	$0	$0	$11,708,108
Retirement Cost											
Total Project Cost	$5,850,702	$5,857,406	$0	$0	$0	$0	$0	$0	$0	$0	$11,708,108

Asset Class: Customer Growth **Business Case ID:**10176

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10176

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10177
Estimate Class: Class 5

Project Information

Name: Area 50 - Residential - Replacement 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 50 - Residential - Replacement Area 50 - Residential - Replacement The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock.

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	738,421	$7,117,226	152

Asset Class: Customer Growth

Business Case ID:10177

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$3,556,575	$3,560,651	$0	$0	$0	$0	$0	$0	$0	$0	$7,117,226
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,556,575	$3,560,651	$0	$0	$0	$0	$0	$0	$0	$0	$7,117,226
Retirement Cost											
Total Project Cost	$3,556,575	$3,560,651	$0	$0	$0	$0	$0	$0	$0	$0	$7,117,226

Asset Class: Customer Growth **Business Case ID:**10177

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10177

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3764
Estimate Class: Class 5

Project Information

Name: Area 60 - Residential - New Construction

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	8,388,938	$106,489,391	115

Asset Class: Customer Growth **Business Case ID:**3764

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$8,454,259	$8,892,394	$10,807,094	$11,211,146	$11,446,388	$11,326,548	$11,316,220	$11,166,965	$11,067,777	$10,800,600	$106,489,391
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$8,454,259	$8,892,394	$10,807,094	$11,211,146	$11,446,388	$11,326,548	$11,316,220	$11,166,965	$11,067,777	$10,800,600	$106,489,391
Retirement Cost											
Total Project Cost	$8,454,259	$8,892,394	$10,807,094	$11,211,146	$11,446,388	$11,326,548	$11,316,220	$11,166,965	$11,067,777	$10,800,600	$106,489,391

Asset Class: Customer Growth **Business Case ID:**3764

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3764

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R1	R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3765
Estimate Class: Class 5

Project Information

Name: Area 60 - Residential - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting
- Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report.

EGD reviews the following when determining feasibility:

- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing
Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 60 - Residential – Replacement. The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,551,781	$73,400,997	51

Asset Class: Customer Growth

Business Case ID:3765

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$10,692,158	$8,875,190	$6,526,446	$6,770,455	$6,912,518	$6,840,147	$6,833,910	$6,743,774	$6,683,874	$6,522,525	$73,400,997
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,692,158	$8,875,190	$6,526,446	$6,770,455	$6,912,518	$6,840,147	$6,833,910	$6,743,774	$6,683,874	$6,522,525	$73,400,997
Retirement Cost											
Total Project Cost	$10,692,158	$8,875,190	$6,526,446	$6,770,455	$6,912,518	$6,840,147	$6,833,910	$6,743,774	$6,683,874	$6,522,525	$73,400,997

Asset Class: Customer Growth **Business Case ID:**3765

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3765

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10184
Estimate Class: Class 5

Project Information

Name: Area 60 - Residential - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 60 - Industrial - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	7,559,997	$21,423,998	517

Asset Class: Customer Growth **Business Case ID:**10184

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$10,705,865	$10,718,133	$0	$0	$0	$0	$0	$0	$0	$0	$21,423,998
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,705,865	$10,718,133	$0	$0	$0	$0	$0	$0	$0	$0	$21,423,998
Retirement Cost											
Total Project Cost	$10,705,865	$10,718,133	$0	$0	$0	$0	$0	$0	$0	$0	$21,423,998

Asset Class: Customer Growth **Business Case ID:**10184

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10184

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth | **Business Case ID:**10185
Estimate Class: Class 5

Project Information

Name: Area 60 - Residential - Replacement 2027+

Type: Enbridge Program | **Start Year:** 2027

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 60 - Residential - Replacement Area 60 - Residential - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.

Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.

Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	2,232,322	$12,938,037	253

Asset Class: Customer Growth

Business Case ID:10185

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$6,465,314	$6,472,723	$0	$0	$0	$0	$0	$0	$0	$0	$12,938,037
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,465,314	$6,472,723	$0	$0	$0	$0	$0	$0	$0	$0	$12,938,037
Retirement Cost											
Total Project Cost	$6,465,314	$6,472,723	$0	$0	$0	$0	$0	$0	$0	$0	$12,938,037

Asset Class: Customer Growth **Business Case ID:**10185

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10185

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3773

Estimate Class: Class 5

Project Information

Name: Area 80 - Residential - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 80 - Residential - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	315,023	$11,227,635	41

Asset Class: Customer Growth **Business Case ID:**3773

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$3,382,564	$3,557,863	$519,754	$539,186	$550,500	$544,736	$544,239	$537,061	$532,291	$519,441	$11,227,635
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,382,564	$3,557,863	$519,754	$539,186	$550,500	$544,736	$544,239	$537,061	$532,291	$519,441	$11,227,635
Retirement Cost											
Total Project Cost	$3,382,564	$3,557,863	$519,754	$539,186	$550,500	$544,736	$544,239	$537,061	$532,291	$519,441	$11,227,635

Asset Class: Customer Growth **Business Case ID:**3773

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3773

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3773
Estimate Class: Class 5

Project Information

Name: Area 80 - Residential - Replacement

Type: Enbridge Program **Start Year:** 2017

Asset Program: Residential - Replacement

Project Type: Residential (Non Subdivision)

Issue/Concern: Residential Replacement refers to a residential replacement customer using a fuel other than natural gas for domestic purposes and is converting to natural gas.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 80 - Residential - Replacement Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	315,023	$11,227,635	41

Asset Class: Customer Growth **Business Case ID:**3773

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$3,382,564	$3,557,863	$519,754	$539,186	$550,500	$544,736	$544,239	$537,061	$532,291	$519,441	$11,227,635
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,382,564	$3,557,863	$519,754	$539,186	$550,500	$544,736	$544,239	$537,061	$532,291	$519,441	$11,227,635
Retirement Cost											
Total Project Cost	$3,382,564	$3,557,863	$519,754	$539,186	$550,500	$544,736	$544,239	$537,061	$532,291	$519,441	$11,227,635

Asset Class: Customer Growth **Business Case ID:**3773

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**3773

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10192

Estimate Class: Class 5

Project Information

Name: Area 80 - Residential - New Construction 2027+

Type: Enbridge Program **Start Year:** 2027

Asset Program: Residential - New Construction

Project Type: Subdivision

Issue/Concern: Residential New Construction refers to a new residential construction development of detached single homes constructed by the builder for domestic purposes.
EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers. Each year, EGD develops a customer additions forecast using a number of information sources:

- Projections of potential customer growth resulting from current projects in different geographical areas of operation based on information from builders, developers and municipalities
- Projections for customer growth based on housing start forecasts and other economic factors such as GDP growth, employment rates, and mortgage rates
- Projections developed by external consultants specializing in population growth forecasting - Municipal long-term plans: EGD extends its gas main within its franchise area to serve new customers when economically feasible, as per criteria prescribed by the Ontario Energy Board (OEB) in the EBO 188 report. EGD reviews the following when determining feasibility:
- The number of potential new customers
- The consumption of natural gas by new customers
- The cost of extending the gas main

The OEB, through EBO 188, directs utilities to have an average PI of 1.0 or greater for their total portfolio of projects and that any one individual project must meet a PI of at least 0.8, ensuring the minimization of cross-subsidization among customers across all projects. This ensures that the costs of projects are recovered from the customer(s) who would directly benefit. Without this approach to system expansion, the utility would not collect enough revenue to fund its projects, and the shortfall would need to be recovered from all other customers. If the cost of the extension is not economically feasible, the applicant(s) will be required to pay a contribution in aid of construction (CIAC). EGD determines the CIAC amount and communicate with the applicant(s) in writing.

Generally, there are three components of capital investments needed to support customer addition requirements:

- Installation costs related to mains, services, and meters
- Material costs related to mains, services and meters
- Costs related to measurement and regulation equipment required to support customer growth.

Assets: All applicable assets.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Area 80 - Residential - New Construction Scope of Work: The Residential Sector Program scope includes annual activities associated with the construction and installation of mains, services, meters, regulator stations, and the associated equipment required to facilitate the connection of new residential or fuel conversion customers within the EGD franchise area. The number of residential customer additions is determined through an annual planning process using a number of sources. Information considered in developing a forecast includes on-the-ground realities such as development projects originating from direct contact with builders, developers, and municipalities. Economic factors and indicators are also considered from reliable third-party data sources. These factors include housing starts forecasts, GDP growth, employment, and mortgage rates. The approach relies on regression models for each customer type and area that is consistent with the approach used by EGD in previous rate applications. Direct customer growth capital is comprised of approximately 65% for services and meters, 30% for mains and 5% for regulator stations. Collectively, material costs make up approximately 15% of the total growth direct capital, while labour is approximately 85%. The installation costs vary depending on installation type. Factors impacting installation costs may include:

- The size and type of material required
- The cost of required permits or fees
- Obtaining any land rights
- Complexity of construction, including the need for horizontal directional drilling, or proximity to a gas main
- Environmental or geotechnical considerations, such as the presence of rock

Resources: Historically, almost all labour resources for the customer growth projects are provided by pipeline contractors. This trend is predicted to continue over the term of the asset management plan.
Solution Impact: EGD is mandated to provide new or upgraded natural gas services to feasible residential and commercial/industrial customers. Feasibility is measured using the the Profitability Index metric that ensures gas cost impacts are minimized. Without the required CAPEX captured under this program, EGD will not be able to provide new or upgraded natural gas services to feasible customers.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	4,301,842	$10,567,766	596

Asset Class: Customer Growth **Business Case ID:**10192
Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$5,280,857	$5,286,909	$0	$0	$0	$0	$0	$0	$0	$0	$10,567,766
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,280,857	$5,286,909	$0	$0	$0	$0	$0	$0	$0	$0	$10,567,766
Retirement Cost											
Total Project Cost	$5,280,857	$5,286,909	$0	$0	$0	$0	$0	$0	$0	$0	$10,567,766

Asset Class: Customer Growth **Business Case ID:**10192

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Growth **Business Case ID:**10192

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Appendix 7.2-2 – Pipe Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Pipe

Business Case ID:1210

Estimate Class: Class 5

Project Information

Name: 2019 Steel Mains Replacement Program

Type: Enbridge Program

Start Year: 2019

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:

• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.

• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.

• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.

In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.

Assets: Steel Mains

Related Program: N/A

Compliance: N

Solution Description:

Scope of Work:

Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).

Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	9,509	$18,843,521	1

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:1210

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$18,843,521	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,843,521
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$18,843,521	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,843,521
Retirement Cost	$0										
Total Project Cost	$18,843,521	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,843,521

Asset Class: Pipe **Business Case ID:**1210

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**1210

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0	R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10321

Estimate Class: Class 5

Project Information

Name: 2020 Steel Mains Replacement Program

Type: Enbridge Program **Start Year:** 2020

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern:

The Steel Main Replacement Program is both a reactive and proactive asset renewal program.
Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:
• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.
• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.
• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.
In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD’s intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.
Assets: Steel Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:
Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).
Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	10,616	$21,598,770	1

Asset Class: Pipe **Business Case ID:**10321
Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$21,598,770	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,598,770
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$21,598,770	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,598,770
Retirement Cost	$0										
Total Project Cost	$21,598,770	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,598,770

Asset Class: Pipe **Business Case ID:**10321

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10321

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0	R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

POWERPLAN AMP

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10322

Project Information

Name: 2021 Steel Mains Replacement Program

Type: Enbridge Program

Start Year: 2021

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:
• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.
• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.
• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.
In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.
Assets: Steel Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:
Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).
Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	11,853	$24,116,965	1

Asset Class: Pipe **Business Case ID:**10322

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$24,116,965	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,116,965
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$24,116,965	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,116,965
Retirement Cost	$0										
Total Project Cost	$24,116,965	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,116,965

Asset Class: Pipe **Business Case ID:**10322

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10322

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0	R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10323

Estimate Class: Class 5

Project Information

Name: 2022 Steel Mains Replacement Program

Type: Enbridge Program **Start Year:** 2022

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:

• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.

• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.

• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.

In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.

Assets: Steel Mains

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:

Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).

Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	13,235	$26,928,763	1

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10323

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$26,928,763	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,928,763
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$26,928,763	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,928,763
Retirement Cost	$0										
Total Project Cost	$26,928,763	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,928,763

Asset Class: Pipe **Business Case ID:**10323

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10323

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0	R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10324

Project Information

Name: 2023 Steel Mains Replacement Program

Type: Enbridge Program

Start Year: 2023

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:

• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.

• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.

• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.

In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD’s intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.

Assets: Steel Mains

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:

Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).

Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	14,781	$30,068,397	1

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10324

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$30,068,397	$0	$0	$0	$0	$0	$0	$0	$0	$0	$30,068,397
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$30,068,397	$0	$0	$0	$0	$0	$0	$0	$0	$0	$30,068,397
Retirement Cost	$0										
Total Project Cost	$30,068,397	$0	$0	$0	$0	$0	$0	$0	$0	$0	$30,068,397

Asset Class: Pipe **Business Case ID:**10324

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10324

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10325

Project Information

Name: 2024 Steel Mains Replacement Program

Type: Enbridge Program

Start Year: 2024

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:

• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.

• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.

• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.

In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.

Assets: Steel Mains

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:

Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).

Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	16,503	$33,574,092	1

Asset Class: Pipe **Business Case ID:**10325

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$33,574,092	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,574,092
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$33,574,092	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,574,092
Retirement Cost	$0										
Total Project Cost	$33,574,092	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,574,092

Asset Class: Pipe **Business Case ID:**10325

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10325

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10326
Estimate Class: Class 5

Project Information

Name: 2025 Steel Mains Replacement Program

Type: Enbridge Program **Start Year:** 2025

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:
• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.
• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.
• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.
In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.
Assets: Steel Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:
Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).
Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	18,426	$37,488,529	1

Asset Class: Pipe

Business Case ID:10326

Estimate Class: Class 5

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$37,488,529	$0	$0	$0	$0	$0	$0	$0	$0	$0	$37,488,529
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$37,488,529	$0	$0	$0	$0	$0	$0	$0	$0	$0	$37,488,529
Retirement Cost	$0										
Total Project Cost	$37,488,529	$0	$0	$0	$0	$0	$0	$0	$0	$0	$37,488,529

Asset Class: Pipe **Business Case ID:**10326

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10326

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID: 10327

Project Information

Name: 2026 Steel Mains Replacement Program

Type: Enbridge Program

Start Year: 2026

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:
• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.
• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.
• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.
In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.
Assets: Steel Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:
Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).
Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	20,575	$41,859,365	1

Asset Class: Pipe

Business Case ID:10327

Estimate Class: Class 5

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$41,859,365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41,859,365
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$41,859,365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41,859,365
Retirement Cost	$0										
Total Project Cost	$41,859,365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41,859,365

Asset Class: Pipe **Business Case ID:**10327

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10327

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:10328

Estimate Class: Class 5

Project Information

Name: 2027 Steel Mains Replacement Program

Type: Enbridge Program

Start Year: 2027

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:

• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.

• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.

• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.

In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.

Assets: Steel Mains

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:

Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).

Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	22,974	$46,739,817	1

Asset Class: Pipe **Business Case ID:**10328

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$46,739,817	$0	$0	$0	$0	$0	$0	$0	$0	$0	$46,739,817
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$46,739,817	$0	$0	$0	$0	$0	$0	$0	$0	$0	$46,739,817
Retirement Cost	$0										
Total Project Cost	$46,739,817	$0	$0	$0	$0	$0	$0	$0	$0	$0	$46,739,817

Asset Class: Pipe **Business Case ID:**10328

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10328

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0	R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:16842

Project Information

Name: 2028 Steel Mains Replacement Program

Type: Enbridge Program

Start Year: 2028

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:

• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.

• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.

• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.

In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.

Assets: Steel Mains

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:

Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).

Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.

Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.
Risks: TRCA, Metrolinx, 3rd party development, IO, City of Toronto, Easements

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	25,653	$52,189,302	1

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:16842

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$52,189,302	$0	$0	$0	$0	$0	$0	$0	$0	$0	$52,189,302
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$52,189,302	$0	$0	$0	$0	$0	$0	$0	$0	$0	$52,189,302
Retirement Cost	$0										
Total Project Cost	$52,189,302	$0	$0	$0	$0	$0	$0	$0	$0	$0	$52,189,302

Asset Class: Pipe **Business Case ID:**16842

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16842

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0	R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:8932

Project Information

Name: Anode Blanket - All Areas (10 Year Plan: 2018-2027)

Type: Enbridge Program

Start Year: 2018

Asset Program: Corrosion Prevention

Project Type: Corrosion Projects

Issue/Concern: This business case is created to group all Anode Blanket projects for all seven operations areas into one program business case to simplify the Risk Assessment process. Financial tracking will be done on the individual Blanket Anode project to provide financial reporting per area.
Justification:The Corrosion Department conducts pipe to soil readings each year on our steel pipelines. When they identify a corrosion area which has fallen below our minimum specifications, they process an order for a anode installation which is completed by the AR&I department. The capital request is for 12 months. Engineering has confirmed the Anode Installation as a compliance project. The Corrosion Prevention Program consists of the annual anode replacement to ensure the steel main system is receiving sufficient cathodic protection. The Program utilizes pipe-to-soil survey results to determine which steel main networks require additional or replacement anodes to improve the level of cathodic protection. In addition to active steel mains, the Corrosion Prevention Programs also cover the corrosion control on steel casings.
Assets: Steel Mains
Related Programs/Business Cases: N/A

Compliance: Y

Solution Description:

Scope of Work: The scope on the corrosion control program includes installation of test stations to monitor cathodic protection performance, as well as anode installation to boost the level of protection. The Corrosion Prevention Program also includes rectifier replacements and remote monitoring system (RMU) upgrades due to obsolescence. This is an annual program that is needed to protect the steel main system against corrosion.
Expenditures: The Corrosion Prevention Program was estimated using the historical anode replacement unit costs. The capital expenditure over the 10 years (2018-2027) for the anode replacement cost is approximately $13M.
Resources: The Corrosion Prevention Program will be delivered with current field resources as traditionally used.
Project Timing & Execution Risks: The Project is a continuation of the annual Corrosion Prevention Program. Identified execution risks: Low execution risk.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	3,955,247	$13,066,028	221

Asset Class: Pipe

Business Case ID:8932

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$1,500,000	$1,210,943	$1,228,735	$1,246,841	$1,265,265	$1,284,014	$1,303,093	$1,322,507	$1,342,263	$1,362,367	$13,066,028
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,500,000	$1,210,943	$1,228,735	$1,246,841	$1,265,265	$1,284,014	$1,303,093	$1,322,507	$1,342,263	$1,362,367	$13,066,028
Retirement Cost											
Total Project Cost	$1,500,000	$1,210,943	$1,228,735	$1,246,841	$1,265,265	$1,284,014	$1,303,093	$1,322,507	$1,342,263	$1,362,367	$13,066,028

Asset Class: Pipe **Business Case ID:**8932

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0R1			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**8932

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0R1			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0	R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:8948

Project Information

Name: Emergency Replacement Blanket - All Areas (10 year plan: 2018-2027)

Type: Enbridge Program

Start Year: 2018

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Throughout the year there is a need to expedite short main replacement projects which typically have short notice. Examples of these types of jobs include cutting out a section of a leaking main/fitting, removing blow-offs that require immediate attention, on going municipal work where we encounter unexpected gas plant - catch basin placements, structures, temporary main cut-out to access municipal plant - water mains etc. The short-cycle replacement projects are initiated by Asset Renewal & Integrity (AR&I) to replace or remove aging or obsolete assets to improve system integrity. The Emergency Replacement Blanket program was created to expedite unforeseen short main replacement Projects that typically have short notice. Examples of these types of jobs include replacement of short section of main or fittings that are leaking, removing blow-off assemblies or mechanical fittings that require immediate attention.
Assets: Distribution Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of work: Projects are initiated by field operations to reactively replace or remove aging or obsolete assets to ensure public and worker safety. This Program is a mandatory annual Program.
Expenditure: The Emergency Replacement Blanket Program cost was estimated using historical actual trends. The capital expenditure for the Program over the 10 years (2018-2027) is $19.8M.
Resources: The Emergency Replacement Blanket work will be delivered with current field resources as traditionally used.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to execute, permitting, and other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$19,800,000	0

Asset Class: Pipe **Business Case ID:**8948

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$1,800,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$19,800,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,800,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$19,800,000
Retirement Cost	$300,000										$300,000
Total Project Cost	$2,100,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$20,100,000

Asset Class: Pipe **Business Case ID:**8948

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**8948

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:16906

Project Information

Name: Replacement Blanket - All Areas (10 year plan: 2028)

Type: Enbridge Program

Start Year: 2028

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Throughout the year there is a need to expedite short main replacement projects which typically have short notice. Examples of these types of jobs include cutting out a section of a leaking main/fitting, removing blow-offs that require immediate attention, on going municipal work where we encounter unexpected gas plant - catch basin placements, structures, temporary main cut-out to access municipal plant - water mains etc. The short-cycle replacement projects are initiated by Asset Renewal & Integrity (AR&I) to replace or remove aging or obsolete assets to improve system integrity. The Emergency Replacement Blanket program was created to expedite unforeseen short main replacement Projects that typically have short notice. Examples of these types of jobs include replacement of short section of main or fittings that are leaking, removing blow-off assemblies or mechanical fittings that require immediate attention.
Assets: Distribution Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of work: Projects are initiated by field operations to reactively replace or remove aging or obsolete assets to ensure public and worker safety. This Program is a mandatory annual Program.
Expenditure: The Emergency Replacement Blanket Program cost was estimated using historical actual trends. The capital expenditure for the Program over in 2028 is $2M.
Resources: The Emergency Replacement Blanket work will be delivered with current field resources as traditionally used.
Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to execute, permitting, and other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe **Business Case ID:**16906

Estimate Class: Class 5

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost	$300,000										$300,000
Total Project Cost	$2,300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,300,000

Asset Class: Pipe **Business Case ID:**16906

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16906

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10087

Estimate Class: Class 5

Project Information

Name: NPS 20 Don River Relocation

Type: Enbridge Project **Start Year:** 2018

Asset Program: Main Replacement

Project Type: Major Pipeline Project

Issue/Concern:

Issue/Concern: The NPS 20 Purpose, Need and Timing is being driven by the following municipal/3rd Party developments:
• Identified conflict with Metrolinx Bridge widening project at Parliament & Lake Shore. This relocation work requires completion in 2019.
• Identified conflict with Keating Railway Bridge extension & widening of the mouth of the Don River. The bridge work is proposed to span from Jul 2020 – Aug 2022.
• Future conflict with First Gulf Development identified with the existing NPS 20 currently in an easement through the First Gulf lands. proposed site construction starting in 2020.

General Concerns: The vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. The current failure projection model is forecasting an exponential increase in the number of corrosion related failures, while the quantitative risk assessment and the 40-year risk projection are showing an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways: Compression couplings; Shallow blow-off valve assemblies that could be damaged during excavation activities;Reduction in the original depth of cover; Continuous exposure of road salt and seasonal ground movement on bridge crossing assets; The lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment; Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion; Latent damages to pipe coatings that were never reported to EGD for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

Assets: NPS 20 Main and associated assets.

Related Programs/BCs: Related BC's 5234, 10026, 10088, 10121, 10122, 10123.

Compliance: N

Solution Description:

Scope of Work: Scope of this project is for the relocation of approximately 2.3 km of NPS 20 HP main from Station B to Parliament St. The preferred option includes the installation of new NPS 20 pipe and new station to feed the existing NPS 20 HP pipeline on the west side of the Don River. This includes approximately 1.5 km of NPS 20 XHP inlet to the new station and 0.5 km of NPS 20 HP outlet/tie-in to the existing NPS 20 HP pipeline at Parliament and Lake Shore.

Related projects:
NPS 30 XHP Replacement project (BC 6423)
NPS 20 Lake Shore KOL (Cherry to Bathurst) (BC 10088). Related BC's 5234, 10026, 10088, 10121, 10122,

10123.

Project details and timing information for the municipal/3rd Party proposed projects under review for possible smaller relocation solutions but the Option 1 to install a new main and a new station at Trinity St (Station A site) is currently the most viable option. The preferred route presented at the open house (Station A) remains as the current proposed solution.
The LTC for the NPS 20 is currently on hold until confirmation of the required timing to address the proposed municipal/3rd Party development projects.
This project is for the relocation of approximately 2.3 km of NPS 20 HP main from Station B to Parliament St. This project is related to the 45.7 km NPS 20 Replacement Project that runs from Lisgar Station to Station B.

Resources: TBD by RFQ

Solution Impact: Relocation required to address sections of pipe with identified conflicts related to the proposed municipal and 3rd Party developments projects.

Project Timing & Execution Risks: 2020 Construction (Q1 start)

UPDATE 8/30/2018: The timelines below may change pending decision on project timing to coordinate with the municipal and 3rd Party development projects.

Assumptions include:
Design & Planning costs in 2018
Two investigative digs completed in 2018
Easements acquired in 2018
Cost of materials procurement in 2019
Cost of station lands in 2019
Construction start 2019, two-year construction period

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,675,938	$35,872,742	119

Asset Class: Pipe **Business Case ID:**10087

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$603,022	$13,016,712	$22,006,030	$850,000	$0	$0	$0	$0	$0	$0	$35,872,742
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$603,022	$13,016,712	$22,006,030	$850,000	$0	$0	$0	$0	$0	$0	$35,872,742
Retirement Cost			$4,000,000								$4,000,000
Total Project Cost	$603,022	$13,016,712	$26,006,030	$850,000	$0	$0	$0	$0	$0	$0	$39,872,742

Asset Class: Pipe **Business Case ID:**10087

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years						R1	
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years	R1						
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10087

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years					R1		
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years						R1	
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**6423

Estimate Class: Class 5

Project Information

Name: NPS 30 Don River Replacement

Type: Enbridge Project **Start Year:** 2017

Asset Program: Main Replacement

Project Type: Major Pipeline Project

Issue/Concern: Main replacement project identified by Asset Management - Pipelines as high-priority. This is an LTC project and the OEB filing number is EB-2018-0108.
Studies have identified structural issues with the Bridge that can become further impaired during flood events which could cause the Bridge to fail resulting in catastrophic failure of the pipeline.
The pipeline is a critical feed to the densely populated urban Toronto area. Damage to this crossing at peak design temperature would result the loss of ~ 92,500 customers, and may take days or weeks to restore service, once the pipeline issue has been addressed.

Assets: NPS 30 XHP Main.
Related Programs/BCs: NPS 20 HP, XHP and Station Replacement project (BC 10087) NPS 20 Lake Shore KOL (Cherry to Bathurst) (BC 10088)

Compliance: N

Solution Description:

Scope of Work: This project is for the replacement of approximately 0.35 km of NPS 30 XHP on the Don River Crossing. This project is a child of the 45.7 km NPS 20 Replacement Project that runs from Lisgar Station to Station B (BC 5234) The current estimate assumes microtunneling under the Don river.
Resources: TBD by RFQ
Solution Impact: Replacement required due to the risk assessment results on the bridge over the Don River.
Project Timing & Execution Risks: The Project was started in 2017 (Construction Q1 start). Identified risks: TRCA, Metrolinx, third-party development.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	237,147	$26,864,009	26

Asset Class: Pipe **Business Case ID:**6423

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$333,801	$829,678	$24,900,530	$800,000	$0	$0	$0	$0	$0	$0	$26,864,009
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$333,801	$829,678	$24,900,530	$800,000	$0	$0	$0	$0	$0	$0	$26,864,009
Retirement Cost			$1,315,903								$1,315,903
Total Project Cost	$333,801	$829,678	$26,216,433	$800,000	$0	$0	$0	$0	$0	$0	$28,179,912

Asset Class: Pipe **Business Case ID:**6423

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							R0
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years						R0	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Pipe **Business Case ID:**6423

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							R0
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							R0
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:11443

Project Information

Name: NPS 12 Martin Grove Rd Main Replacement Ph 2

Type: Enbridge Project

Start Year: 2023

Asset Program: Main Replacement

Project Type: Replacement

General Concerns: ¬¬¬¬Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings, and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The Quantitative Risk Assessment (QRA) and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
• Compression couplings
• Shallow blow-off valve assemblies that could be damaged during excavation activities
• Reduction in the original depth of cover
• Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
• Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
• Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
• Latent damages to pipe coatings that were never reported to EGD for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment
Site-specific Concerns: The Martin Grove project is a size-for-size replacement of NPS 12 HP steel main on Martin Grove Road. This project has been split into two phases within the 10 Year Asset Management Plan.
Phase 1 addresses a section of the pipeline identified to be in the upper limits of the ALARP risk zone and has been scheduled in the first half of the 10-year Asset Management Plan. Phase 2 addresses sections of the pipeline identified to be in the lower limits of the ALARP zone and has been scheduled in the second half of the plan. Phase 2 requires some additional investigation to confirm pipe condition status, and identify the appropriate scope and replacement timing. The replacement of the NPS 12 Martin Grove KOL vintage steel main helps address known pipeline integrity and operational field concerns by proactively replacing steel mains approaching intolerable risk due to failing and/or poor condition pipes. This results in the prevention of the future failures of these critical distribution system assets.
Phase 2:Scope is still being determined and includes replacing approximately 3.1 km along Martin Grove Rd of NPS 12 HP steel main from Burnhamthorpe Road to Clement Road and the abandonment of approximately 3.1 km of existing NPS 12 HP steel main along Martin Grove Road. The following may be included: crossing the Mimico Creek along Martin Grove Road from Rathburn Road to Savalon Court; the replacement of two pressure reduction stations along the existing pipeline route on Martin Grove Rd which requires approximately 170 m of NPS main on Rathburn Road to be replaced and approximately 80 m of NPS 12 main on Burnhamthorpe Road to Burnlem Drive to be replaced. The new route will follow Municipal Right of Way where possible and is planned for construction in 2024. Planning and engineering will take place in 2023.
Assets: NPS 12 HP steel main
Related Programs and BCs: BC 6421, 10086.

Compliance: N

Solution Description:

Related BC 6421 Planning dollars, 10086 2019
Scope of Work: This is for Phase 2 of the Martin Grove replacement project. Remaining 3.1km of pipe will be looked at. Possible replacement of full 3.1km or a portion of this from Burnhamthorpe to Enterprise Road. Replacement of one district station.
Resources: 2020 - 2024 OTC Phase 2 and resources TBD
Solution Impact: Main replacement project identified by Asset Management - Pipelines as high priority. Replacement is required due to age, pipeline condition and risk assessment results.
Project Timing & Execution Risks: This initiative is scheduled to start in 2023. Risks identified: moratoriums and easements.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	25,617	$11,749,725	3

Asset Class: Pipe **Business Case ID:**11443

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$400,000	$10,749,725	$600,000	$0	$0	$0	$0	$0	$0	$0	$11,749,725
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$400,000	$10,749,725	$600,000	$0	$0	$0	$0	$0	$0	$0	$11,749,725
Retirement Cost		$447,988									$447,988
Total Project Cost	$400,000	$11,197,713	$600,000	$0	$0	$0	$0	$0	$0	$0	$12,197,713

Asset Class: Pipe **Business Case ID:**11443

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years					R0		
Once in 10 to 100 years							
Once in 100 to 1000 years						R1	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0					
Once in 10 to 100 years							
Once in 100 to 1000 years			R1				
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**11443

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years					R0		
Once in 10 to 100 years							
Once in 100 to 1000 years					R1		
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years				R0			
Once in 10 to 100 years							
Once in 100 to 1000 years					R1		
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:10089

Estimate Class: Class 5

Project Information

Name: NPS 12 St. Laurent Ottawa North Main Replacement (2021+)

Type: Enbridge Program

Start Year: 2021

Asset Program: Main Replacement

Project Type: Major Pipeline Project

General Concerns: Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third party damages to pipe coating, and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The Quantitative Risk Assessment (QRA) and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:
• Compression couplings
• Shallow blow-off valve assemblies that could be damaged during excavation activities
• Reduction in the original depth of cover
• Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
• Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
• Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
• Latent damages to pipe coatings that were never reported to EGD for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment
Site-specific concerns: Unable to determine leaks on this pipeline due to the close proximity of the NPS 12 XHP 470 psi system. Cathodic protection was not installed until the early 70's. Approximately 429 services are connected off this XHP network, which may be susceptible to degradation.
Assets: NPS 12 XHP system with approximately 429 services.
Related Programs/Business Cases: BC 6422, 10288, 10289, 10290, 10291, 10292, 10293, 10294

Compliance: N

Solution Description:

Related BC 6422 for 2017-2019 This BC 10089 is for 2020 and beyond.
Scope of Work: Full replacement of main comprising Network 6584 - The NPS 12 XHP St. Laurent Ottawa North line is 13.3 km and operates at 275 psi as Network 6584. It runs from south of St. Laurent Control Station (6584:653:1969) to Rockcliffe Control Station (Station #6B558A). It does not include the main south from St Laurent Control Station to Industrial Ave as well as the NPS 12 lateral main to Trans Alta (6584:1234:1235) including the NPS 12 lateral main along Tremblay Rd. but does not include the crossing at the Rideau River to Station #61171A.
• In 2018, pressure increase to Avenue O.
• In 2019, approx. 3.1 km of plastic main will be installed on Tremblay and the Avenues and the services transferred over to IP. Also, due to a road moratorium, 2 km of 6" PE IP main on St Laurent between Donald Street and Montreal needs to be brought forward from 2021 to 2019, including approximately 80 services.
• In 2021, approx. 8.9 km of plastic main will be installed and all the services will be transferred over to IP, four IP stations will be abandoned, one new station will be installed and approximately. 6.5 km of NPS 1 to 8 will be abandoned. Approximately. 0.6 km of 4" SC will be installed to feed four stations that cannot be increased due to the age of the pipe.

• In 2022, approx. 12 km of steel main will be installed, one new station will be built, Rockcliffe and St Laurent Control will be rebuilt, and approximately 9.3 km of NPS 12/16 will be abandoned.
Resources:
2018 - EGD crews
2019 - external contractor
2021-2022 – bids to be solicited
Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results
Project Timing & Execution Risks: Identified risks: moratoriums and easements.
Timing: This initiative starts in 2019.
• 2018 - Pressure Increase Avenue O
• 2019 - Replace Tremblay and the Avenues with IP and transfer 174 off XHP to IP. Replace 2.0 km of XHP to IP on St. Laurent from Donald Ave to Montreal Ave. and transfer 129 customers 2021- Replace St Laurent with PE IP and transfer 466 customers off XHP to IP
• 2022- install NPS 12 XHP tying into network 6580 just south of St Laurent Control all the way to Rockcliffe Station.
Looking at installing the pipe on NCC lands. Need to be aware of moratoriums and special permits from NCC. 42% contingency used.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	15,396	$52,131,583	1

Asset Class: Pipe

Business Case ID:10089

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$9,239,682	$40,641,901	$2,250,000	$0	$0	$0	$0	$0	$0	$0	$52,131,583
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$9,239,682	$40,641,901	$2,250,000	$0	$0	$0	$0	$0	$0	$0	$52,131,583
Retirement Cost	$999,000	$7,572,343	$630,000								$9,201,343
Total Project Cost	$10,238,682	$48,214,244	$2,880,000	$0	$0	$0	$0	$0	$0	$0	$61,332,926

Asset Class: Pipe **Business Case ID:**10089

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years				R0R1			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R1	R0				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:** 10089

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years				R0R1			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years				R0R1			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:10343

Estimate Class:

Project Information

Name: 2020 Vintage PE Main Replacement Program

Type: Enbridge Program

Start Year: 2020

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	3,127	$2,275,540	2

Asset Class: Pipe **Business Case ID:**10343

Estimate Class:

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$2,275,540	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,275,540
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,275,540	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,275,540
Retirement Cost											
Total Project Cost	$2,275,540	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,275,540

Asset Class: Pipe **Business Case ID:**10343

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R0R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0	R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10343

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R0R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:10345

Estimate Class:

Project Information

Name: 2021 Vintage PE Main Replacement Program

Type: Enbridge Program

Start Year: 2021

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	3,775	$2,745,970	2

Asset Class: Pipe **Business Case ID:**10345

Estimate Class:

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$2,745,970	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,745,970
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,745,970	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,745,970
Retirement Cost											
Total Project Cost	$2,745,970	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,745,970

Asset Class: Pipe **Business Case ID:**10345

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R0R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0	R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10345

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R0R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10346
Estimate Class:

Project Information

Name: 2022 Vintage PE Main Replacement Program

Type: Enbridge Program **Start Year:** 2022

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	4,561	$3,319,220	2

Asset Class: Pipe **Business Case ID:**10346

Estimate Class:

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$3,319,220	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,319,220
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,319,220	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,319,220
Retirement Cost											
Total Project Cost	$3,319,220	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,319,220

Asset Class: Pipe **Business Case ID:**10346

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R0R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0	R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10346

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R0R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class:

Business Case ID:10347

Project Information

Name: 2023 Vintage PE Main Replacement Program

Type: Enbridge Program

Start Year: 2023

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	5,523	$4,018,034	2

Asset Class: Pipe **Business Case ID:**10347

Estimate Class:

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$4,018,034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,018,034
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,018,034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,018,034
Retirement Cost											
Total Project Cost	$4,018,034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,018,034

Asset Class: Pipe **Business Case ID:**10347

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:** 10347

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10348

Estimate Class:

Project Information

Name: 2024 Vintage PE Main Replacement Program

Type: Enbridge Program **Start Year:** 2024

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	6,694	$4,870,195	2

Asset Class: Pipe **Business Case ID:**10348

Estimate Class:

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$4,870,195	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,870,195
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,870,195	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,870,195
Retirement Cost											
Total Project Cost	$4,870,195	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,870,195

Asset Class: Pipe **Business Case ID:**10348

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10348

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class:

Business Case ID:10349

Project Information

Name: 2025 Vintage PE Main Replacement Program

Type: Enbridge Program

Start Year: 2025

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	8,121	$5,909,653	2

Asset Class: Pipe **Business Case ID:**10349

Estimate Class:

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$5,909,653	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,909,653
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,909,653	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,909,653
Retirement Cost											
Total Project Cost	$5,909,653	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,909,653

Asset Class: Pipe **Business Case ID:**10349

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10349

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

POWERPLAN AMP

Asset Class: Pipe

Business Case ID:10350

Estimate Class:

Project Information

Name: 2026 Vintage PE Main Replacement Program

Type: Enbridge Program

Start Year: 2026

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern: Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	9,864	$7,177,882	2

Asset Class: Pipe **Business Case ID:**10350

Estimate Class:

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$7,177,882	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,177,882
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,177,882	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,177,882
Retirement Cost											
Total Project Cost	$7,177,882	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,177,882

Asset Class: Pipe **Business Case ID:**10350

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10350

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10351
Estimate Class:

Project Information

Name: 2027 Vintage PE Main Replacement Program

Type: Enbridge Program **Start Year:** 2027

Asset Program: Main Replacement

Project Type: Replacement

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	11,992	$8,725,557	2

Asset Class: Pipe **Business Case ID:**10351

Estimate Class:

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$8,725,557	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,725,557
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$8,725,557	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,725,557
Retirement Cost											
Total Project Cost	$8,725,557	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,725,557

Asset Class: Pipe **Business Case ID:**10351

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10351

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**17984

Estimate Class:

Project Information

Name: 2028 Vintage PE Main Replacement Program

Type: Enbridge Program **Start Year:** 2028

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern:

Pre-1977 plastic mains are the earliest plastic mains used within the distribution system and include vintage resins such as Aldyl A that are considered brittle and have a tendency to crack over time. This time-dependent cracking in the Aldyl A pipe wall can be accelerated by additional stress intensifiers, such as a large number of connections, squeeze-offs, and the presence of rock impingement points caused by rocky soil types that significantly shortens the expected asset life of the Aldyl A plastic mains. Because of its rapid deterioration and high consequence failure mode, a replacement program is required to manage the increasing risk over the long term.
Assets: Plastic Mains
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The strategy is to increase the replacement rate to approximately 10 kilometers per year for pre-1977 plastic mains in the next 10 years, with an immediate focus on replacing plastic mains that have experienced the slow crack growth type failure due to known stress intensifiers such as rocky soil type, as well as replacing the early vintage field trail plastic mains predating the official implementation of plastic main in the early 1970s. EGD will continue to monitor asset conditions to evaluate the asset life of Pre-1977 plastic mains and determine the long term replacement pace required to maintain the average asset age below the estimated asset life.
Resources: Operations crews, Planning, Construction contractor crews.
Solution Impact: Refer to Asset Plan section 5.2.6 for discussion on Distribution Plastic Mains.
Project Timing & Execution Risks: The Project is a continuation of the Vintage PE Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	14,587	$10,614,591	2

Asset Class: Pipe

Business Case ID:17984

Estimate Class:

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$10,614,591	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,614,591
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,614,591	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,614,591
Retirement Cost											
Total Project Cost	$10,614,591	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,614,591

Asset Class: Pipe **Business Case ID:**17984

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**17984

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**8930
Estimate Class: Class 5

Project Information

Name: 2020 Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2020

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern:

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$3,000,000	0

Asset Class: Pipe

Business Case ID:8930

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$3,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,000,000
Retirement Cost											
Total Project Cost	$3,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,000,000

Asset Class: Pipe **Business Case ID:**8930

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**8930

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10281
Estimate Class: Class 5

Project Information

Name: 2021 Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2021

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10281

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**10281

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10281

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10282

Project Information

Name: 2022 Rebillable Relocation Blanket - All Area

Type: Enbridge Program

Start Year: 2022

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10282

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**10282

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10282

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10283

Project Information

Name: 2023 Rebillable Relocation Blanket - All Area

Type: Enbridge Program

Start Year: 2023

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe **Business Case ID:**10283

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**10283

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10283

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10284

Project Information

Name: 2024 Rebillable Relocation Blanket - All Area

Type: Enbridge Program

Start Year: 2024

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe

Business Case ID:10284

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**10284

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10284

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10285

Project Information

Name: 2025 Rebillable Relocation Blanket - All Area

Type: Enbridge Program

Start Year: 2025

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10285

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**10285

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10285

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10286
Estimate Class: Class 5

Project Information

Name: 2026 Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2026

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10286

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**10286

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10286

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10287

Estimate Class: Class 5

Project Information

Name: 2027 Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2027

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.
Assets: Integrity & Distribution Mains
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:
• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.
Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe **Business Case ID:**10287

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**10287

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10287

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:16783

Project Information

Name: 2028 Rebillable Relocation Blanket - All Area

Type: Enbridge Program

Start Year: 2028

Asset Program: Rebillable Relocation

Project Type: Rebillable Relocation

Issue/Concern: Relocation projects are generally requested by the municipality or other third party to address location conflicts with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. A relocation project is required when a municipality, road authority, other utility or third party constructs or reconstructs a road, bridge, railway, canal, building etc. and the proposed work is deemed to be in conflict with an existing gas plant. The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Assets: Integrity & Distribution Mains

Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: A relocation project is the relocation of existing plant – size for size, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work. The construction activity can conflict with a gas pipeline in the following ways:

• Insufficient final cover is left over the gas main after construction.
• The gas main is left in a location that prevents or inhibits future access or maintenance.
• There is insufficient cover over the main during construction to protect it from being damaged by vehicles or equipment.
• There is potential undermining of the gas main during construction.
• Ease of construction for third party
• Insufficient clearances between the gas main and proposed construction of underground structures
• Change in land ownership

The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction, and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.

Expenditures: The capital expenditure over the 10 years (2019-2028) for this annual Program is $66.1M. The baseline-funding requirement is estimated using historical trends. Major, large-scale, transit-related relocations are not included in the estimate beyond 2020, since design details are not sufficient at this time to understand the impact of the work on the gas infrastructure. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost-share structure outlined in specific franchise agreements.

Resources: Relocation projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed large-scale relocation projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Impact: Removing conflict with third party proposed work and infrastructures.
Project Timing & Execution Risks: This initiative is a continuation of the annual relocation program. Execution risks identified: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,700,000	0

Asset Class: Pipe

Business Case ID:16783

Estimate Class: Class 5

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000
Retirement Cost											
Total Project Cost	$7,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,700,000

Asset Class: Pipe **Business Case ID:**16783

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16783

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19346

Estimate Class: Class 5

Project Information

Name: 2020 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2020

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe

Business Case ID:19346

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19346

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19347
Estimate Class: Class 5

Project Information

Name: 2021 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2021

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe

Business Case ID:19347

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19347

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19347

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19349
Estimate Class: Class 5

Project Information

Name: 2022 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2022

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:19349

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19349

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19349

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19352
Estimate Class: Class 5

Project Information

Name: 2023 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2023

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:19352

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19352

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19352

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19353
Estimate Class: Class 5

Project Information

Name: 2024 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2024

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe **Business Case ID:**19353
Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19353

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19353

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19355
Estimate Class: Class 5

Project Information

Name: 2025 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2025

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe **Business Case ID:**19355

Estimate Class: Class 5

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19355

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19355

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19354
Estimate Class: Class 5

Project Information

Name: 2026 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2026

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD’s Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe **Business Case ID:**19354

Estimate Class: Class 5

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19354

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19354

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19350

Estimate Class: Class 5

Project Information

Name: 2027 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2027

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe

Business Case ID:19350

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19350

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19350

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19351
Estimate Class: Class 5

Project Information

Name: 2028 Non-Rebillable Relocation Blanket - All Area

Type: Enbridge Program **Start Year:** 2028

Asset Program: Non-Rebillable Relocation

Project Type: Non-Rebillable Relocation

Issue/Concern:

Relocation projects are generally requested by the municipality or other third party to address location conflict with existing gas facilities. These projects are deemed mandatory as per the terms and conditions in the franchise agreement between EGD and the municipality or third party. Relocation could also be necessitated when gas plants are inadvertently installed on private property, or when land right agreements for the gas plants to stay on private properties expire and renewal of the agreement is not an option.
The purpose of the Relocation Blanket Program is to relocate gas carrying assets that are in conflict with third party proposed work which mitigates the risk by coming up with a resolution. The Planning department within EGD ensures that such conflicts are avoided to the extent possible. If they cannot be avoided, the group ensures that they are resolved within the framework of the various agreements, in most cases by relocating the existing gas infrastructure, to ensure the continued safe and reliable delivery of natural gas to customers. The relocation will renew the asset since the asset will be replaced with new pipe.

Compliance: N

Solution Description:

A relocation Project is the relocation of existing plant – size for size in most cases, such as mains, services, meters, and regulators, because of direct conflicts with third party proposed work.
Below are a few drivers for non-rebillable relocation of a gas pipeline:
? Insufficient cover over the gas main during original installation, causing conflict with proposed third party work
? Change in land ownership or expiration of land right agreement
? Misalignment of existing pipeline onto private property
The Relocation Blanket Program is an annual ongoing program that involves the planning, design, procurement, construction and commissioning of the relocated pipelines. Specific Project details will be developed over time as the work proposed by third parties is reviewed by EGD's Planning department through the mark-up process.
Expenditures
The total capital expenditure for this Program is approximately $2M per year from the years 2019-2028. The baseline-funding requirement is estimated using historical actuals. Since there is no sufficient way to project the non-rebillable relocation needs, the long term cost requirement for this program is estimated at the current spend level of $2M per year. The actual funding required each year is subject to change, as it is dependent on municipal/other party infrastructure plans, the degree of interference associated with the design and the cost share structure outlined in specific franchise agreements. The budget will be reviewed and adjusted annually to reflect the actual capital requirement.
Resources
Relocation Projects are traditionally planned, designed and permitted by the Planning department. The construction is managed by the Construction department while the contractor executes the work. Currently there are no confirmed long term large-scale relocation Projects that would suggest a resource ramp up is required. Relocation Projects will continue to be managed by the current internal resources as done historically.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,000,000	0

Asset Class: Pipe

Business Case ID:19351

Estimate Class: Class 5

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Pipe **Business Case ID:**19351

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**19351

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**9551
Estimate Class: Class 5

Project Information

Name: Fiber Optics on Vital and Critical Mains

Type: Enbridge Project **Start Year:** 2020

Asset Program: Integrity Initiatives - Pipe

Project Type: Engineering

Issue/Concern: Damages caused by third parties defined as contractor, home owner, landowner, other utility etc. This is typically due to excavation activities. Additional complexities listed below have not been implemented and will be considered in the future development of the risk model as part of continuous improvement:

a. Location-specific corrosion factors such as stray current, specific soil conditions (such as contaminated soil, poor backfill materials), types of field applied coating, soil type etc.
b. Interaction between multiple threats, such as combined effects of dented pipes due to excavation activities and corrosion.
c. Failure of compression couplings leading to significant release of gas and pressure due to exposed points of thrust or ground movement.
d. Inadvertent damage of pipe fittings and valves which have shallow depth of cover during excavation activities.
e. Reduction of original depth of cover due to urban development.
f. Variation of population densities due to growth and non-residential purposed areas.
g. Constructability issues during repair and replacement activities.
Business Case-specific concerns: Mechanical damage caused by unauthorized third-party excavations is the most significant threat to pipeline safety, having the highest probability of occurrence and the highest probability of damage. Threats of this type are described as time independent or may fall under human error. Operational dimensions that include both integrity management and leak management can be enhanced as a result of implementing fiber optic technology.
Assets: <list related assets>
Related Programs and BCs: <list if applicable>

Compliance: N

Solution Description:

Scope of Work: Fiber optic monitoring cables will be installed along some major vital and critical mains. There is an opportunity to install the fiber optic cable along major pipelines that are being constructed as part of the 10 year asset plan. Such pipelines include ; Don River project, KOL replacement project, St. Laurent replacement, Rideau Reinforcement projects.
Resources: construction contractor crews and Operations crews.
Solution Impact: Fiber-optic monitoring uses a fiber-optic cable buried near the pipeline to monitor various properties of light transmitted through the cable, which is sensitive to vibrations and pressures transmitted through the ground. Fiber-optic sensing systems operate on a real-time basis. The information is available continuously, 24 hours a day and seven days a week. Thus, incident response capacity and quality will be superior to current practice since operators will possess the ability to quickly responding to unauthorized third-party intrusion detection on pipelines. As well, it will be possible to pinpoint the location of leaks, if and when they occur. New construction pipeline applications represent the most economic option for installing fiber-optic cable along vital mains in EGD's territory.
Project Timing & Execution Risks: Prioritized within a 5 year period (2019-2023). Identified risks: This project is dependant on the construction and associated project risks of planned major pipeline projects (e.g. St. Laurent replacement).

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	17,432	$4,415,000	6

Asset Class: Pipe **Business Case ID:**9551
Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$1,358,000	$1,092,500	$1,381,500	$583,000	$0	$0	$0	$0	$0	$0	$4,415,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,358,000	$1,092,500	$1,381,500	$583,000	$0	$0	$0	$0	$0	$0	$4,415,000
Retirement Cost											
Total Project Cost	$1,358,000	$1,092,500	$1,381,500	$583,000	$0	$0	$0	$0	$0	$0	$4,415,000

Asset Class: Pipe **Business Case ID:**9551

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years					R0		
Once in 10 to 100 years					R1		
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0					
Once in 10 to 100 years		R1					
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**9551

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years				R0			
Once in 10 to 100 years				R1			
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years				R0			
Once in 10 to 100 years				R1			
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:17364

Project Information

Name: NPS 8 Blackburn Extension

Type: Enbridge Project

Start Year: 2018

Asset Program: Integrity Retrofit - Pipe

Project Type: Integrity Retrofit

Issue/Concern: An Area 60 pipeline was communicated to have exceeded the Maximum Operating Pressure (MOP) threshold for integrity mains (operating above 29.5% SMYS) by the MOP team. The pipeline is identified as NPS 8 Blackburn Bypass that is operating at 470 PSI which corresponds to 30.8% SMYS. The current operating set pressure for the pipeline is 470 PSI, corresponding to 30.8% of pipe material SMYS, which means that the pipeline needs to be included in the Integrity Management Program, according to TSSA CAD, FS-220-16, Clause 10.3.11. If the pipelines are operating above 29.5% SMYS, they fall within the definition of an IMP pipeline that is in scope of EGD's Integrity Management Program (IMP). Typically, this means that In Line Inspection (ILI) is performed and follow up integrity digs are performed to mitigate risk by measuring/monitoring the condition of the high risk operating pipeline. The IMP is in response to TSSA CAD 2016, 10.3.11: "For the protection of the pipeline, the public and the environment, the operating company shall develop a pipeline integrity management program for steel pipelines operated at 30% or more of the SMYS of the pipe at MOP that complies with the applicable requirements of clause 3.2 of CSA Z662-15." and is a mandatory regulatory requirement.
Assets: Network #6580
Related Programs/BCs: N/A

Compliance: Y

Solution Description:

Scope of Work: Retrofits required include:
i. launcher installation (with and Oversize & Nominal) and an NPS 8 Isolation Block Valve installed at Innes Rd. and Cleroux Cres.
ii.ii. LSF component to be removed and replaced with straight pipe and barred tee at Innes Rd. and Opp 1916 Du Clairvaux
iii. LSF component to be removed and replaced with straight pipe and barred tee at Innes Rd. and Opp 1920 Du Clairvaux
iv. Cut out LSF and install WSS Tee (bypass required due to busy intersection) at Innes Rd. and Orleans Blvd.
v. Cut out LSF and install 3D or greater Elbows, Tee's associated with LSF would have to be cut-out and replaced with pipe and elbows >3D. This is a very busy intersection at Innes Rd. and Orleans Blvd.
vi. Replace elbow with long radius elbow at Opp 3519 Innes Rd.
vii. Receiver Install - The pipeline section ends under Innes Rd, thus recommend the more practical approach of routing the receiver trap configuration (Receiver with oversize and nominal, NPS 8 Isolation Block Valve) to the south side of Innes Rd. aat Opp 3519 Innes Rd. Resources: Contractor / TFS
Resources: <list resources>
Solution Impact: Multiple excavations, some temporary shut-off may be required, some bypass' required and Innes Rd. and Orleans Blvd. is a busy intersection.
Project Timing and Execution Risks: This initiative is proposed to start in 2018. Identified risks: Underground conditions unknown.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$3,855,000	0
Option 2		0	$3,500,000	0

Asset Class: Pipe **Business Case ID:**17364

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$0	$3,855,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,855,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$0	$3,855,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,855,000
Retirement Cost											
Total Project Cost	$0	$3,855,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,855,000

Asset Class: Pipe **Business Case ID:**17364

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**17364

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:8949

Project Information

Name: Relay Blanket - All Areas (10 year plan: 2018-2027)

Type: Enbridge Program

Start Year: 2018

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: This Business Case is created to group all Blanket Relay Busniess Cases for all seven areas into one program business case to simplify the Risk Assessment process. Financial tracking will be done on the individual Blanket Relay project to provide financial reporting per area.
Justification: Throughout the year, there is a need to relay services to EGD customers for various reasons. These relays could be initiated by Asset Renewal & Integrity for safety and integrity purposes, or they could be requested by a third party (contractor, city, authority, customers, etc.) to accommodate building demolition, utility conflict, public safety, or service alteration. Other work included in this budget include non-targeted, proactive AMP fitting riser replacements and the replacement of distribution services, the link between the distribution main and the customer's meter set. Of the different service materials, both steel and plastic services behave similarly to their parent steel and plastic mains of the same vintage. Therefore, vintage steel services and vintage plastic services will be replaced during vintage steel main and vintage plastic main replacements. Copper services (inventory of 6,000) will require a proactive replacement program, as they are prone to failure. In addition to the proactive program, the Service Relay Blanket is also needed to manage reactive service replacement on a regular basis.
Assets: Distribution Services
Related Programs/Business Cases: N/A

Compliance: Y

Solution Description:

Scope:
Similar to the Main Replacement Blanket, a Service Relay Blanket is used to relay services to customers for various reasons throughout the year. These relays could be initiated by field operations for safety, integrity and compliance purposes, such as relaying a leaking or shallow service line. Service relays could also be requested by a third party (contractor, city, authority, customers, etc.) to accommodate building demolition, utility conflicts, and for public safety reasons. This Program is an on-going annual Program.
In conjunction with the Service Relay Blanket, the Sewer Safety Program was initiated to mitigate the safety risks specific to sewer laterals/mains and to prevent the inadvertent intersection with a natural gas pipeline (cross bore). This usually occurs in trenchless technology whereby a gas main or service being installed pierces through the sewer line. Over time, this causes a blockage of the sewer line, and shows up when a customer notices poor drainage from their homes water drainage system. The cross bore becomes a public risk when the sewer becomes blocked, and the customer, their contractor or the municipality cleans out the sewer line with rotary cutting and/or water jetting equipment. The equipment is extended down through the sewer line and rotates to cut through any obstruction that is blocking the sewer line including the natural gas pipeline that has penetrated the sewer. This damage can result in a natural gas escape into homes and buildings and can create a safety issue. Because the sewer acts as a direct path for escaping gas into the customer's home, there is potential for ignition and/or an explosion. Preventing the creation of new cross bores is dependent on the continued work on locating underground infrastructure to ensure trenchless technology installation methods do not introduce a new risk. Mitigation of the potential interaction of natural gas lines with sewer lines is achieved through performing private sewer lateral locates using specialized equipment, completing site assessments and visual verification prior to the installation of new natural gas pipelines and constructing sewer lateral specific transition holes and excavations to expose the pipeline. The cost of the sewer lateral locates are factored into the Service Relay Blanket.

A third component of the Service Relay Program Business Case is the Copper Services Replacement Program. It is a proactive replacement program aimed at removing the remaining active copper services from the system prior to failure. Copper services are facing both external and internal corrosion that may eventually result in leaks or choked services. This proactive program will replace copper services with new plastic services and anodeless risers over the next 10 years.

Expenditures: The total capital expenditure for this Program is $222M from years 2018-2027. The Program cost is estimated using historical actuals and failure projections.
Resources: Construction contractor crews and Operations crews.
Solution Impact: Refer to Asset Plan section 5.2.7 for discussion on Distribution Services.
Project Timing & Execution Risks: This project starts in 2018. Identified execution risks are: Potential resource capacity, timing and certainty due to third party driven work.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	3,489,976	$222,024,754	28

Asset Class: Pipe

Business Case ID:8949

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Tota
Direct Capital Cost	$14,500,000	$17,722,914	$20,295,803	$21,195,208	$22,174,994	$23,183,476	$24,260,587	$25,233,391	$26,222,726	$27,235,655	$222,024,75
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$14,500,000	$17,722,914	$20,295,803	$21,195,208	$22,174,994	$23,183,476	$24,260,587	$25,233,391	$26,222,726	$27,235,655	$222,024,75
Retirement Cost											
Total Project Cost	$14,500,000	$17,722,914	$20,295,803	$21,195,208	$22,174,994	$23,183,476	$24,260,587	$25,233,391	$26,222,726	$27,235,655	$222,024,75

Asset Class: Pipe **Business Case ID:**8949

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**8949

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:16907

Estimate Class: Class 5

Project Information

Name: Relay Blanket - All Areas (10 year plan: 2028)

Type: Enbridge Program

Start Year: 2028

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: This Business Case is created to group all Blanket Relay Busniess Cases for all seven areas into one program business case to simplify the Risk Assessment process. Financial tracking will be done on the individual Blanket Relay project to provide financial reporting per area.
Justification: Throughout the year, there is a need to relay services to EGD customers for various reasons. These relays could be initiated by Asset Renewal & Integrity for safety and integrity purposes, or they could be requested by a third party (contractor, city, authority, customers, etc.) to accommodate building demolition, utility conflict, public safety, or service alteration. Other work included in this budget include non-targeted, proactive AMP fitting riser replacements and the replacement of distribution services, the link between the distribution main and the customer's meter set. Of the different service materials, both steel and plastic services behave similarly to their parent steel and plastic mains of the same vintage. Therefore, vintage steel services and vintage plastic services will be replaced during vintage steel main and vintage plastic main replacements. Copper services (inventory of 6,000) will require a proactive replacement program, as they are prone to failure. In addition to the proactive program, the Service Relay Blanket is also needed to manage reactive service replacement on a regular basis.
Assets: Distribution Services
Related Programs/Business Cases: N/A

Compliance: N

Solution Description:

Scope of Work: Similar to the Main Replacement Blanket, a Service Relay Blanket is used to relay services to customers for various reasons throughout the year. These relays could be initiated by field operations for safety, integrity and compliance purposes, such as relaying a leaking or shallow service line. Service relays could also be requested by a third party (contractor, city, authority, customers, etc.) to accommodate building demolition, utility conflicts, and for public safety reasons. This Program is an on-going annual Program.
In conjunction with the Service Relay Blanket, the Sewer Safety Program was initiated to mitigate the safety risks specific to sewer laterals/mains and to prevent the inadvertent intersection with a natural gas pipeline (cross bore). This usually occurs in trenchless technology whereby a gas main or service being installed pierces through the sewer line. Over time, this causes a blockage of the sewer line, and shows up when a customer notices poor drainage from their homes water drainage system. The cross bore becomes a public risk when the sewer becomes blocked, and the customer, their contractor or the municipality cleans out the sewer line with rotary cutting and/or water jetting equipment. The equipment is extended down through the sewer line and rotates to cut through any obstruction that is blocking the sewer line including the natural gas pipeline that has penetrated the sewer. This damage can result in a natural gas escape into homes and buildings and can create a safety issue. Because the sewer acts as a direct path for escaping gas into the customer's home, there is potential for ignition and/or an explosion. Preventing the creation of new cross bores is dependent on the continued work on locating underground infrastructure to ensure trenchless technology installation methods do not introduce a new risk. Mitigation of the potential interaction of natural gas lines with sewer lines is achieved through performing private sewer lateral locates using specialized equipment, completing site assessments and visual verification prior to the installation of new natural gas pipelines and constructing sewer lateral specific transition holes and excavations to expose the pipeline. The cost of the sewer lateral locates are factored into the Service Relay Blanket.
A third component of the Service Relay Program Business Case is the Copper Services Replacement Program. It

is a proactive replacement program aimed at removing the remaining active copper services from the system prior to failure. Copper services are facing both external and internal corrosion that may eventually result in leaks or choked services. This proactive program will replace copper services with new plastic services and anodeless risers over the next 10 years.

Expenditures: The total capital expenditure for this Program in 2028 is $28.2M. The Program cost is estimated using historical actuals and failure projections.
Resources: Construction contractor crews and Operations crews.
Solution Impact: Refer to Asset Plan section 5.2.7 for discussion on Distribution Services.
Project Timing & Execution Risks: This project starts in 2018. Identified execution risks are: Potential resource capacity, timing and certainty due to third party driven work.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	391,851	$28,252,443	24

Asset Class: Pipe

Business Case ID:16907

Estimate Class: Class 5

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$28,252,443	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,252,443
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$28,252,443	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,252,443
Retirement Cost											
Total Project Cost	$28,252,443	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,252,443

Asset Class: Pipe **Business Case ID:**16907

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16907

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:1418

Project Information

Name: 2019 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2019

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD’s field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	153,292	$4,406,944	56

Asset Class: Pipe **Business Case ID:**1418

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$4,406,944	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,406,944
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,406,944	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,406,944
Retirement Cost	$3,600,038										$3,600,038
Total Project Cost	$8,006,982	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,006,982

Asset Class: Pipe **Business Case ID:**1418

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**1418

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10223

Project Information

Name: 2020 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2020

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures:The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD's field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	169,222	$4,483,144	61

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10223

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$4,483,144	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,483,144
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,483,144	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,483,144
Retirement Cost	$3,662,319										$3,662,319
Total Project Cost	$8,145,463	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,145,463

Asset Class: Pipe **Business Case ID:**10223

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10224

Project Information

Name: 2021 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2021

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD's field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	278,785	$6,841,115	66

Asset Class: Pipe **Business Case ID:**10224

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$6,841,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,841,115
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,841,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,841,115
Retirement Cost	$3,725,677										$3,725,677
Total Project Cost	$10,566,792	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,566,792

Asset Class: Pipe

Business Case ID:10224

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10224

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10261

Project Information

Name: 2022 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2022

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD's field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	407,027	$9,279,287	71

Asset Class: Pipe **Business Case ID:**10261

Estimate Class: Class 5

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$9,279,287	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,279,287
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$9,279,287	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,279,287
Retirement Cost	$3,790,131										$3,790,131
Total Project Cost	$13,069,418	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,069,418

Asset Class: Pipe **Business Case ID:**10261

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10261

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10262

Project Information

Name: 2023 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2023

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD’s field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	222,097	$10,839,819	33

Asset Class: Pipe **Business Case ID:**10262

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$10,839,819	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,839,819
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,839,819	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,839,819
Retirement Cost	$3,855,701										$3,855,701
Total Project Cost	$14,695,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,695,520

Asset Class: Pipe **Business Case ID:**10262

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10262

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10263

Project Information

Name: 2024 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2024

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD’s field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	241,649	$13,004,692	30

Asset Class: Pipe **Business Case ID:**10263
Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$13,004,692	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,004,692
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$13,004,692	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,004,692
Retirement Cost	$5,883,606										$5,883,606
Total Project Cost	$18,888,298	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,888,298

Asset Class: Pipe **Business Case ID:**10263

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10263

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe | **Business Case ID:**10264
Estimate Class: Class 5

Project Information

Name: 2025 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2025

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD's field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,049,750	$19,538,524	87

Asset Class: Pipe **Business Case ID:**10264

Estimate Class: Class 5

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$19,538,524	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,538,524
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$19,538,524	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,538,524
Retirement Cost	$7,980,524										$7,980,524
Total Project Cost	$27,519,048	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,519,048

Asset Class: Pipe **Business Case ID:**10264

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10264

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe
Estimate Class: Class 5

Business Case ID:10265

Project Information

Name: 2026 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2026

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD's field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,417,246	$24,845,675	92

Asset Class: Pipe **Business Case ID:**10265

Estimate Class: Class 5

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$24,845,675	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,845,675
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$24,845,675	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,845,675
Retirement Cost	$10,148,234										$10,148,234
Total Project Cost	$34,993,909	$0	$0	$0	$0	$0	$0	$0	$0	$0	$34,993,909

Asset Class: Pipe **Business Case ID:**10265

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10265

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10266

Project Information

Name: 2027 AMP Fitting Replacement Program

Type: Enbridge Program

Start Year: 2027

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD's field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,526,877	$25,275,506	98

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10266

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$25,275,506	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,275,506
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$25,275,506	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,275,506
Retirement Cost	$10,323,798										$10,323,798
Total Project Cost	$35,599,304	$0	$0	$0	$0	$0	$0	$0	$0	$0	$35,599,304

Asset Class: Pipe **Business Case ID:**10266

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10266

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10267
Estimate Class: Class 5

Project Information

Name: 2028 AMP Fitting Replacement Program

Type: Enbridge Program **Start Year:** 2028

Asset Program: Service Relay

Project Type: Relays

Issue/Concern: The AMP Fitting Replacement Program is a proactive replacement Program to replace copper risers and the AMP fittings that transition plastic services to copper risers. The AMP fitting causes a disturbance in the flow of gas, creating a low-pressure zone after the fitting when the gas flow becomes turbulent. This turbulence causes an erosion-corrosion failure mechanism to occur, resulting in a pinhole or a circumferential crack. As can be seen in the copper riser failure projection, the condition of copper risers will degrade significantly over the next two decades, resulting in a larger number of leaks. Based on the long term condition of the asset, a proactive program is required to mitigate the risk to the customers and the public.
Assets: Copper risers
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Gradual pacing increase to achieve 20,000 units of AMP Fitting & Copper Riser replacement per year, starting with 4000 units per year in 2019 and increasing to 20000 units per year by 2026 and beyond. The AMP Fitting Replacement Program will target the replacement of the copper risers and the transition of AMP fittings. EGD will strive to replace vintage plastic services while replacing the copper risers. The copper risers and AMP fittings will be replaced over the next 18 years and will be completed by approximately 2035.
Expenditures: The capital expenditure for this Program over the next 10 years (2019-2028) is $144M. The Program cost is estimated using the most current actual unit cost from the 2017 AMP Fitting Replacement Program. No contingency has been considered in this unit cost.
Resources: The program is currently being executed using EGD's field operations resources. As the Program pace increases over the next 10 years, EGD will continue to evaluate the cost efficiency and monitor resource capacity among other operations workloads. External resources may be engaged to execute a part or all of the work should it prove to be a more cost efficient approach.
Project Timing & Execution Risks: The Project is a continuation of the program that begins in 2018. Identified execution risks: Resource capacity to execute as the program ramps up to 20,000 copper riser replacement per year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,640,451	$25,712,772	103

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:10267

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$25,712,772	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,712,772
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$25,712,772	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,712,772
Retirement Cost	$10,502,400										$10,502,400
Total Project Cost	$36,215,172	$0	$0	$0	$0	$0	$0	$0	$0	$0	$36,215,172

Asset Class: Pipe **Business Case ID:**10267

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10267

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7732

Estimate Class: Class 5

Project Information

Name: AJAX Reinforcement

Type: Enbridge Project **Start Year:** 2020

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need:

- Customer growth data coupled with Zoning Bylaw and Site Plan applications suggest that Network 4543 is expected to experience significant load growth
- System lacks supplementary supply from the northern end of the network; network flexibility is compromised and reliability is a concern during emergency or maintenance situations
- Due to current system configuration, a NPS 4"ST main (located on Station St, between Old Station St and Thomson St) acts as a bottleneck in the HP system, dropping pressure by approximately 8psi and hindering maximum pressures available downstream at station inlets.

Risk if not completed: System risks without reinforcement:

- Three stations that feed gas into the network will have inlet pressures below the minimum, starting in 2022
- The low inlet pressures at the stations will inhibit the ability to deliver gas to the network, downstream of the station
- In 2022 there are approximately 21120 customers that would be connected to the network that may be impacted.

Assets (preferred option):

- Preferred reinforcement option is comprised of approximately 2.1km of 6"ST HP-pipe along Church St N, originating from the existing NPS 16"ST XHP Vital Main (at Taunton Rd & Church St N) and terminating at Church St N and Rossland Rd W.
- Two (2) stations would need to be installed – (1) XHP-HP Station at Church & Taunton and (1) HP-IP Station at Church & Rossland.
- Additionally, 450m of 8"PE-IP would need to be installed along Rossland Rd W, from Church St N to 120m E. of Harkins Dr.

Related Programs & BCs: N/A

Compliance: N

Solution Description:

Scope of Work: 2.1km of 6"ST-HP on Church St N. from Taunton Rd (Node 45810115) to Rossland Rd W. Install 2 stations - (1) XHP-HP Station at Church & Taunton and (1) HP-IP Station at Church & Rossland. Install 450m of 8"PE-IP on Rossland Rd W, from Church St to 120m E. of Harkins Dr.
Resources: Construction contractor crews and Operations crews.

Solution Impact:
Project Benefits
This project will allow the Ajax IP-network to be permanently biased to be fed from the north of the city, which is much closer to Pickering Gate Station, which feeds the area. This will make future reinforcements less frequent by having the gas travel a shorter distance through pipes, resulting in a lower pressure drop. The new line will also run through an area shown in the Ajax official plan as zoned for residential development. Installing this line will make servicing these customers very inexpensive once the area is developed. Installing this pipe will also keep pressures on the XHP line at Kingston Rd & Salem Rd as well as the HP at Kingston Rd and Westney Rd above the system minimum, allowing for the continued reliable operation of the network and for new customer to be added in 2022 and beyond. The new line will also add significant flexibility to the system in emergency situations.
Project Timing and Execution Risks: With current system configurations at design Degree Day of 41, it is forecasted that station inlet pressures at WESTNEY & HWY-2, ADAMS & RITCHIE, and KNAPTON & ELGIN will likely reach minimum system limits in forecast year 2023. Therefore, it is recommended that the reinforcement is executed by end of year 2022. The reinforcement is intended to ensure that there is always enough capacity to support the growth of any given year up to 2026, as well as continue to support the network in subsequent winters. Identified risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	232,727	$3,212,025	103

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:7732

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$160,000	$3,052,025	$0	$0	$0	$0	$0	$0	$0	$0	$3,212,025
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$160,000	$3,052,025	$0	$0	$0	$0	$0	$0	$0	$0	$3,212,025
Retirement Cost											
Total Project Cost	$160,000	$3,052,025	$0	$0	$0	$0	$0	$0	$0	$0	$3,212,025

Asset Class: Pipe **Business Case ID:**7732

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7732

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16744
Estimate Class:

Project Information

Name: Amaranth System Reinforcement

Type: Enbridge Project **Start Year:** 2021

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern:

See email from Meetpal regarding station costing and that he is unable to cost out station component. Email Attached (PLEASE DO NOT DELETE THIS NOTE) Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need:
The existing station equipment is inadequate to handle volume flow increase brought by the yearly load LRP growth as projected. Hence, at a certain time it will not be operating efficiently and thus impact the IP downstream. The rebuild of the two stations will mitigate the identified issue. Consequent to the yearly LRP load growth as projected; the HP source at the tail end of the NPS4 ST HP main will be degraded at a certain time. The NPS 8 ST HP main reinforcement will mitigate the identified issue.
Risk if not completed: If the two stations are not rebuilt, downstream pressures will be below the minimum system pressure due to the droop.
If the NPS 4 HP ST main is not looped with a larger diameter pipe (NPS 8), the HP minimum inlet pressure will be below the minimum system pressure which again will make the station droop and thus affecting the IP system pressures which will be below the minimum system pressure.
Assets (preferred option): Phase 1 2021 ? Rebuild the district station feeding NW 2176 (RS20031A, Mill St) Phase 2022 ? Rebuild the district station feeding NW 2166 (RS20024A, Melody Lane) Phase 3 2025 ? Install app. 5000m NPS 8 ST HP Main Reinforcement on Sideroad 5 from Crago Station Outlet main Rd to 5th Line
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:
Phase 1 2021 - Rebuild the district station feeding NW 2176 (RS20031A, Mill St)
Phase 2 2022 - Rebuild the district station feeding NW 2166 (RS20024A, Melody Lane)
Phase 3 2025 - Install app. 5000m NPS 8 ST HP Main Reinforcement on Sideroad 5 from Crago Station Outlet main Rd to 5th Line
Resources: Construction contractor crews and Operations crews.
Solution Impact: Project Benefits: Once the two stations are rebuilt, it will have the capacity to handle the expected LRP’s load growth as projected yearly. ? The existing NPS 4 ST HP main has limited capacity to boost the pressures which is seen to degrade due to the yearly load growth on the IP system. The NPS 8 ST HP main reinforcement provides the needed capacity, mitigating the degradation of pressures on the HP tail end.
Project Timing & Execution Risks:
Yr 2021 Phase 1
Yr 2022 Phase 2
Yr 2025 Phase 3 The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in

the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	142,270	$5,147,342	39

Asset Class: Pipe **Business Case ID:**16744

Estimate Class:

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$100,000	$100,000	$0	$4,947,342	$0	$0	$0	$0	$0	$0	$5,147,342
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$100,000	$100,000	$0	$4,947,342	$0	$0	$0	$0	$0	$0	$5,147,342
Retirement Cost				$53,523							$53,523
Total Project Cost	$100,000	$100,000	$0	$5,000,865	$0	$0	$0	$0	$0	$0	$5,200,865

Asset Class: Pipe **Business Case ID:**16744

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16744

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7726
Estimate Class: Class 5

Project Information

Name: Barrie to Collingwood XHP Pressure Elevation

Type: Enbridge Project **Start Year:** 2025

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.
Project Purpose/ Need: The low pressure in this 400 psig XHP system will reach the MSP of 100 psig at the tail end (grey County) in 2025. As of 2017, there are 28,138 customers on this network. Without reinforcement, forecasted 3,471 customers may not be able to be added.
Risk if not completed: Due to the long distance from the station to the tail end of Grey County, with a single source feed from Barrie Gate, a potential low pressure is forecasted with customer growth - pressure at Grey County station will reach the minimum pressure of 100Psi by 2025-2026, which could inhibit customer additions in the growing areas of Springwater, Wasaga Beach, Clearview and Collingwood. Low pressure in this XHP system will reach the minimum system pressure at the tail end of the network by 2025. By 2025, 30915 customers are anticipated to be connected to this network.
Assets: A combination of Pipe and Station Assets to meet the project objectives.

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:
• Install a XHP-XHP Regulating Station on the NPS 8 XHP outlet in Barrie Gate Station, after the tee to the NPS 12 XHP ST pipeline, outlet pressure will be set at 385 Psig.
• Increase the Barrie Gate Station outlet from 400 psig to 480 psig.
• Install a XHP-XHP Kicker Station at Phelpston near node 53011504, outlet pressure will be set at 300 Psig.
• Install 400m of NPS 6 XHP ST gas main at Phelpston (node 53011504 to 53011182) to connect Barrie system and Rugby system, isolate the NPS 8 XHP ST and NPS 6 XHP ST.
• Remove the current Kicker Station 3648317 at Phelpston.
• Install a XHP-XHP Station on the NPS 8 XHP ST near Stayner, outlet pressure will be set at 385 Psig.
• Replace 11 km of 8" SC XHP on Flos 4 Rd W, from node 53011125 to 53011094 (TBD).
Resources: Construction contractor crews and Operations crews.
Solution Impact: Customer growth Benefit: With this pressure elevation, we can gain more capacity for this XHP system, to meet the customer growth along this one-way fed XHP line, including Collingwood, Wasaga Beach, Springwater, and Clearview.
Project Timing and Execution Risks: This pressure elevation project is suggested to be executed before December 2025. Considering 11 km of 8" SC XHP on Flos 4 Rd W might not be qualified to elevate pressure, this replacement will need to be completed prior to this pressure elevation. Identified risks: The Long Range Plan is

determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	574,177	$7,722,688	107

Asset Class: Pipe

Business Case ID:7726

Estimate Class: Class 5

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$7,722,688	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,722,688
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,722,688	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,722,688
Retirement Cost	$630,661										$630,661
Total Project Cost	$8,353,350	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,353,350

Asset Class: Pipe **Business Case ID:**7726

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7726

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R1	R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7706
Estimate Class: Class 5

Project Information

Name: Bathurst Reinforcement

Type: Enbridge Project **Start Year:** 2018

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.
Project Purpose/Need: The year-over-year amount of customers being fed by Parkview & Doris have seen a slight decline since 2011, but according to forecasted growth data there will be an increase. Without reinforcement in 2019, the station inlet pressure will drop below a sustainable value. This progression should stop after 2019 as pressures could potentially drop below 100psi and the station will be deemed inoperable. Evidence of densification has become apparent through load sheets. Without the reinforcement, growth cannot be supported in the downstream system.
Pressure issue/concern: The minimum system pressure is forecasted to be infeasible by 2018. Customer growth issue/ concern: As of 2017, there are 11650 customers on this network. Without reinforcement, supply security may not be maintained.
Assets: The proposed pipeline installation will originate near Steeles Ave W and Bathurst St and will terminate at Betty Ann Dr and Bathurst St. Approximately 3.2km of NPS12 will need to be installed on Bathurst St and a 55psi station installed at the terminus point of Betty Ann Dr and Bathurst St.
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Install 3.2km of NPS 12 ST HP (1802014 to 1770274).
Resources: Construction contractor crews and Operations crews.

Solution Impact: The addition of another station and the proposed pipeline will help alleviate some of the pressure concerns at Parkview & Doris. If this concern is addressed other problems can be solved:
• Allowing future growth in the downstream network
• Creating a redundant, secure source for approx. 11,650 customers in the downstream network
• Reducing the need for future rebuild of Parkview & Doris
According to customer growth data, there will be an increase in customers from 2017 to 2026. This increase will lower the station inlet pressure year over year. On a peak day, Parkview & Doris feeds approximately 11,650 customers. Most of the customers dispersed throughout the network are of the residential type. By creating a redundant source those customers will have ample supply in the event Parkview & Doris is damaged or taken out of service for repairs.
Project Timing and Execution Risks: The Project is proposed to start in 2018. The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes
Project Timing: According to the model, at design Degree Day 41, the pressure at Parkview & Doris will drop below the minimum inlet for the station in 2017. During simulation, a difference of 10% was recorded between field and

model readings. As such, there is likely continued ability to operate the station until 2019. Historical pressures at this location have been noisy. Low pressures have been recorded in 2014 and 2015, which do fall in line with predictions, but temperatures have not reached design conditions for 2017. The reinforcement is intended to ensure that there is enough capacity to support the growth of any given year, as well as continue to support the network through subsequent winters.

Identified Risks: System Risk without this Reinforcement - Parkview and Doris station may not maintain 55Psi outlet pressure, and could impact customers in the downstream network - There are approximately 11,650 customers that are fed by this single station as of 2017. Therefore, any disruption at the station could have major customer impacts.

• According to forecasted growth projections, the number of customers in the network are set to increase and without this reinforcement, growth cannot be supported in the downstream system

• ERX monitors and actual data have shown that the station will drop below the 100Psi minimum inlet by 2019

According to the model, at design Degree Day 41, the pressure at Parkview & Doris will drop below the minimum inlet for the station in 2017. During simulation, a difference of 10% was recorded between field and model readings. As such, there is likely continued ability to operate the station until 2019. Historical pressures at this location have been noisy. Low pressures have been recorded in 2014 and 2015, which do fall in line with predictions, but temperatures have not reached design conditions for 2017. The reinforcement is intended to ensure that there is enough capacity to support the growth of any given year, as well as continue to support the network through subsequent winters.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	549,214	$9,957,651	78

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:7706

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$496,812	$8,810,839	$650,000	$0	$0	$0	$0	$0	$0	$0	$9,957,651
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$496,812	$8,810,839	$650,000	$0	$0	$0	$0	$0	$0	$0	$9,957,651
Retirement Cost											
Total Project Cost	$496,812	$8,810,839	$650,000	$0	$0	$0	$0	$0	$0	$0	$9,957,651

Asset Class: Pipe **Business Case ID:**7706

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7706

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7739
Estimate Class: Class 5

Project Information

Name: Clarence Rockland XHP

Type: Enbridge Project **Start Year:** 2024

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.
Project Purpose/ Need:

• Pressures in this area are low, relative to their pressure class, and indicate growth in downstream systems.
• Generally these regions are experiencing growth and new feeds are needed to support the forecasted growth.
• No redundant feed for many customers at design day within network boundaries.
Pressure issue/concern: The minimum system pressure is 470 Psi, and is forecasted to be infeasible by 2025.
Customer growth issue/ concern: As of 2017, there are 6013 customers on this network. Without reinforcement, forecasted 871 customers may not be able to be added.
Risk if not completed:
System risk without the reinforcement:
• The system may not be able to maintain outlet pressures and could result in a number of downstream impacts - this is a one way fed system at the tail end of the Ottawa East XHP.
• Approximately 6000 existing customers would be potentially lost over the winter of 2025-2026 - low pressures at the stations indicate growth downstream. The current system would be unable to continue adding 13 customers per year.
Assets (preferred option): - 18.0 km - NPS 4 XHP main - from Innes Rd & Frank Kenny Rd - to Joanisse Rd & Du Golf Rd (Hwy 1) - along Frank Kenny Rd, Colonial Rd, Du Golf Rd
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: This reinforcement includes the installation of approximately 18Km of NPS 4 ST XHP gas main. Zero service relays will be required, however there is a potential of servicing new residential and commercial customers, including the Sarsfield community. This reinforcement ties in on the west at Innes Road and Frank Kenny Road in Ottawa to the intersection on the east tie in of Du Golf Road and Joanisse Road in Clarence-Rockland. It will include the use of Frank Kenny Road, Colonial Road and Du Golf Road.
Resources: Construction contractor crews and Operations crews.
Solution Impact: Customer growth benefit: The current system would be unable to continue adding 13 customers per year as of the proposed in-service date. Pressure benefit : A pressure improvement from 120 psig to 225 psig are predicted at the tail-end stations.
Project Timing & Execution Risks: The main in its entirety will need to be installed by the winter of 2025. The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	11,851	$7,569,879	2

Asset Class: Pipe **Business Case ID:**7739

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$94,500	$7,475,379	$0	$0	$0	$0	$0	$0	$0	$0	$7,569,879
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$94,500	$7,475,379	$0	$0	$0	$0	$0	$0	$0	$0	$7,569,879
Retirement Cost											
Total Project Cost	$94,500	$7,475,379	$0	$0	$0	$0	$0	$0	$0	$0	$7,569,879

Asset Class: Pipe **Business Case ID:**7739

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7739

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16745
Estimate Class:

Project Information

Name: County Rd 9 Reinforcement

Type: Enbridge Project **Start Year:** 2024

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Note- Date changed per the direction of Meetpal (see email from Meetpal on April 26th at 9:52am) also attaching the email from him in RIVA (see attachements)
Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need: Customer growth in the surrounding area will drive this reinforcement. Increase in load will cause tail end pressures at inlet of station 51014A (LOUISA & MARY DISTRICT) to drop over 10% every year without reinforcement. And due to the long stretch on about 11 km of 4" SC XHP on Centre Line Rd and then 5 km of 2" SC XHP, the pressure at the tail end will be very sensitive and drop abruptly.
Pressure issue/concern: The minimum pressure is 100 Psi, and is forecasted to be infeasible by 2024 Customer growth issue/ concern: As of 2017, there are 2698 customers on this network. Without reinforcement, forecasted 1221 customers (2018-2028) may not be able to be added.
Risk if not completed: Due to the long stretch on 2" SC XHP, the tail end pressure will drop quickly with the customer adding. The pressure drop about 100 psig over this 2" XHP. This reinforcement will limit the risk of customer loss up to forecast temperatures under normal operating conditions. Customer additions might be limited if this reinforcement isn't completed. The average pressure drop due to customer adding will be over 10% at the inlet of station 51014A.
Assets (preferred option): Proposed 5 km of 4" SC XHP in Creemore on County Rd 9, from Centre line Rd to Mary St (station 51014A inlet).
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Phase 1 in 2022, Proposed 2.5 km of 12" SC XHP on Innisfil Beach Rd, from Thornton Gate Station #3613819 outlet to County Rd 53. - Phase 2 in 2024 Proposed 6 km of 8" SC XHP on Lockhart Rd, from tail end of existing 8" SC XHP at Lockhart Rd/Yonge St to 25 Sideroad. "
Resources: Construction contractor crews and Operations crews.
Solution Impact: Ability to maintain minimum required system pressure, maintain capacity, and meet customer demand.
Project Timing and Execution Risks: LRP growth modeling indicates that this project will be needed in 2024 based on the minimum operating pressure of the system. Project Benefits This reinforcement will allow continued customer additions in the network as identified in LRP. It can solve the capacity constraint issue on 2" SC XHP on County Rd 9. Identified risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

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Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	201,208	$3,051,994	95
Option 2		252,844	$5,880,882	62

Asset Class: Pipe **Business Case ID:**16745

Estimate Class:

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$3,051,994	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,051,994
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,051,994	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,051,994
Retirement Cost	$18,983										$18,983
Total Project Cost	$3,070,977	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,070,977

Asset Class: Pipe **Business Case ID:**16745

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16745

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16748
Estimate Class: Class 5

Project Information

Name: Erin IP System Reinforcement

Type: Enbridge Project **Start Year:** 2018

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.
Project Purpose/ Need: The purpose of Phase 1 main reinforcement is to provide capacity on the east side of district station RS21100A, Erin District along Main Street and improve the degrading pressures Phase 2 and 3 will provide capacity and will improve the degrading pressures southwest of the station along Trafalgar Road. Pressure issue/concern: The minimum system pressure is 10 Psi, and is forecasted to be infeasible by 2019 (when the first phase is proposed to start). Customer growth issue/concern: As of 2018, there are 2039 customers on this network. Without reinforcement, forecasted 866 customers may not be able to be added.
Risk if not completed: At its current condition, the system will not be able to supply gas for large load additions (i.e., subdivision and commercial) as per the LRP projections since existing mains have limited capacity and pressures below the minimum system pressure. As per model results, in years 2019, 2023, and 2025 pressures were below minimum system pressures.
Assets (preferred option):
Phase 1 Yr 2019 ? Upsize app. 2600m existing NPS 4 ST/PE to NPS 6 PE on Main St (Stn RS21100A, ERIN DISTRICT to Wellington Rd 124)
Phase 2 Yr 2023 ? Upsize app. 3100m existing NPS 4 ST to NPS 8 PE on Sideroad 17 t (Stn RS21100A, ERIN DISTRICT to Wellington Rd 24)
Phase 3 Yr 2025 ? Upsize app. 5000m existing NPS 4 ST to NPS 8 PE on Wellington Rd 24 (Sideroad 17 to Orangeville St)
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work:
Phase 1 Yr 2019 - Upsize app. 2600m existing NPS 4 ST/PE to NPS 6 PE on Main St (Stn RS21100A, ERIN DISTRICT to Wellington Rd 124)
Phase 2 Yr 2023 - Upsize app. 3100m existing NPS 4 ST to NPS 8 PE on Sideroad 17 t (Stn RS21100A, ERIN DISTRICT to Wellington Rd 24)
Phase 3 Yr 2025 - Upsize app. 5000m existing NPS 4 ST to NPS 8 PE on Wellington Rd 24 (Sideroad 17 to Orangeville St)
Resources: Construction contractor crews and Operations crews.
Solution Impact: Project Benefits: The existing NPS 4 main has limited capacity to accommodate the LRP projected load growth. The installation of the NPS 6 & 8 PE reinforcement will provide the needed capacity and improve pressures.
Customer growth Benefit: With reinforcement, forecasted addition of 866 customers (2018-2028) will be possible.
Pressure Benefit: With reinforcement, the pressure would increase to above the minimum requirements.
Project Timing & Execution Risks:

Phase 1 Yr 2019
Phase 2 Yr 2023
Phase 3 Yr 2025
Identified Risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	287,978	$5,962,939	68
Option 2		331,431	$11,709,698	40

Asset Class: Pipe **Business Case ID:**16748

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$20,000	$1,454,120	$0	$0	$0	$1,711,158	$0	$2,777,661	$0	$0	$5,962,939
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$20,000	$1,454,120	$0	$0	$0	$1,711,158	$0	$2,777,661	$0	$0	$5,962,939
Retirement Cost		$15,068				$25,687		$41,430			$82,185
Total Project Cost	$20,000	$1,469,188	$0	$0	$0	$1,736,845	$0	$2,819,091	$0	$0	$6,045,124

Asset Class: Pipe **Business Case ID:**16748

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16748

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7740
Estimate Class: Class 5

Project Information

Name: Kemptville Reinforcement

Type: Enbridge Project **Start Year:** 2022

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need:

a. Low Pressures @ Stations - Pressures in this area are low, relative to their pressure class, and indicate growth in downstream systems.
b. Customer Growth - Generally these regions are experiencing growth and new feeds are needed to support the forecasted growth. In particular the Kemptville subdivision is already equipped with reasonable backbone piping sizes but is fed from relatively far downstream the XHP source of Kemptville Gate, which has travelled through a significant amount of NPS 4 piping.
c. Undersized piping - The NPS 4 XHP line heading to Merrickville-Wolford is long and causes significant pressure drop.
Pressure issue/concern: The minimum system pressure is forecasted to be infeasible by 2023. Customer growth issue/ concern: As of 2017, there are 1,482 customers on this network. Without reinforcement, forecasted 302 customers may not be able to be added.
Risk if not completed: System risk without the reinforcement - a single station feeds a one way fed network. - approximately 3500 existing customers could be lost over the winter of 2024-2025 - without the reinforcement, nodes at the end of the network show below the minimum pressure requirements
Assets (preferred option):
a. Station: - XHP to IP - Intersection of Hwy 43 & Merlyn Wilson Rd
b. Main: - 9.5 km - NPS 6 XHP main - from Innes Rd & Frank Kenny Rd - to Joanisse Rd & Du Golf Rd (Hwy 1) -along Frank Kenny Rd, Colonial Rd, Du Golf Rd.
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: New XHP to IP District Station at Hwy 43 and Merlyn Wilson Rd. 9.5km of 6” ST XHP from Kemptville Gate to Rideau River Rd & Hwy 43.
Resources: Construction contractor crews and Operations crews
Solution Impact: Project Benefits –
Customer growth Benefit: with reinforcement, forecasted addition of 302 customers (2026) will be possible.
Pressure Benefit : with reinforcement, the pressure would increase to 450 Psig from 300 at the station inlets.
Project Timing & Execution Risks:

- Station in 2023
- Main in 2024

Identified Risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	54,400	$5,025,454	15

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:7740

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$186,000	$4,839,454	$0	$0	$0	$0	$0	$0	$0	$0	$5,025,454
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$186,000	$4,839,454	$0	$0	$0	$0	$0	$0	$0	$0	$5,025,454
Retirement Cost											
Total Project Cost	$186,000	$4,839,454	$0	$0	$0	$0	$0	$0	$0	$0	$5,025,454

Asset Class: Pipe **Business Case ID:**7740

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7740

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R1	R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:7743

Estimate Class: Class 5

Project Information

Name: L'Original Reinforcement

Type: Enbridge Project

Start Year: 2019

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need: This reinforcement is to add capacity within EGD's pipe network to: 1) Satisfy the current contractually allowable demand of the LVC customer Ivaco Rolling Mills, which is 6800 m3/h 2) Support customer growth of the downstream HPPE network This geographic area sits at the eastern tail-end of XHP network 6587, which is fed exclusively by Lancaster gate to the southeast.
Pressure issue/concern : The minimum system pressure is forecasted to be infeasible by 2020. Customer growth issue/ concern: As of 2017, there are 2,039 customers on this network. Without reinforcement, forecasted 24 customers may not be able to be added.
Risk if not completed : System risk without the reinforcement - May not be able to satisfy contractual demand of a large volume customer along with supporting forecasted customer growth - This network is at the mid-tail end of the east valley line, with pressures approaching the minimum - This XHP system is operating at over 30% SMYS. If this line pressure drops below 30% SMYS, this reinforcement will not be sufficient - approximately 1430 customers would potentially be lost over the winter of 2017-2018 - there are approximately 2039 customers forecasted to be connected by 2017.
Assets (preferred option): Station: 62328A set to 80 psig Main: - 10.0 km - NPS 4 XHP main - from County Rd 17 & Hwy 11 - to Cassburn Rd & Emerson Rd - along Hwy 11.
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Installation of approximately 9.5km of NPS 4 XHP along Cassburn Rd (11). There are no current customers impacted by this reinforcement, although there is the potential to add new customers along this route.
Resources: Construction contractor crews and Operations crews.
Solution Impact: Project Benefits Customer growth Benefit: Pressures in this area are low, relative to their pressure class, and indicate growth in downstream systems. The current system would be unable to continue adding four (4) customers per year as of the proposed in-service date.
Project Timing & Execution Risks: Installation of NPS 4 XHP main by winter 2020-2021. Identified Risks The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

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Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	368,028	$4,069,108	129

Asset Class: Pipe

Business Case ID:7743

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$172,500	$3,896,608	$0	$0	$0	$0	$0	$0	$0	$0	$4,069,108
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$172,500	$3,896,608	$0	$0	$0	$0	$0	$0	$0	$0	$4,069,108
Retirement Cost											
Total Project Cost	$172,500	$3,896,608	$0	$0	$0	$0	$0	$0	$0	$0	$4,069,108

Asset Class: Pipe **Business Case ID:**7743

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1		R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7743

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1		R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7710
Estimate Class: Class 5

Project Information

Name: McCowan Ave HP Reinforcemen

Type: Enbridge Project **Start Year:** 2020

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need: This reinforcement is meant to support upstream and downstream load growth, bring back the flexibility we previously had in the system and to reduce dependency of other stations feeding the IP network. Both McCowan & Southdale and South Unionville districts have been set to 40psi and 50psi respectively in 2016 to increase the tail?end pressures in the HP network. M&R has posed concerns with leaving these stations set at their current outlet pressures for an extended period of time. If the reinforcement is completed the set pressures can be increased to 55psi, the downstream networks intended pressure setting. Monitor points have been set up near the tail?end of the HP network to determine if a reinforcement would be required in the near future. Mostly Large Volume Customers and HP?IP district stations are fed off of the HP network and maintaining an inlet above 100psi has always been an Enbridge standard (as per the PDR). As indicated, there are many alternate sources available, but the pressure tends to diminish as it approaches the tail?end of the network. This constraint will become apparent in the event of a damage or repairs need to be performed on one of the alternate feeds. If the reinforcement is performed at the date indicated key decisions can be made in the field with high levels of confidence.
Pressure issue/concern: McCowan & Southdale District is approaching the minimum inlet pressure of 100psi. There is a need to shift the flow to other sources in order to boost pressures near the tail?end of the HP network Risk if not completed: If the inlet to STN 36013A ? MCCOWAN & SOUTHDALE DISTRICT or STN 32758A ?SOUTH UNIONVILLE & McCOWAN DISTRICT (MARKHAM) fall below 100psi during design conditions in 2021 approximately 5,000 customers downstream will be lost. Scheduled maintenance for both stations beyond 2017 will need to occur in summer months due to the instability of the HP feed. If this reinforcement is completed by the in?service date either station could be taken offline for servicing without customer losses.
Assets (preferred option):
2021: Install XHP to HP station at Steeles Ave and IBM. The station will have a designed inlet of 485psi with an outlet of 175psi. The primary feed for this station will come from Victoria Gate. The tie?in for the inlet will be off of the NPS 30 SC and the outlet will feed into the NPS 12 ST HP on Steeles Ave. Approx. 25m for the inlet and 25m for the outlet will be required.
2022: Raise STN 36013A ? MCCOWAN & SOUTHDALE DISTRICT from 40psi to 50psi 2024: Install 1.4km of NPS 12 SC main on Tapscott Ave from Passmore Ave to Steeles Ave 2024: Raise pressure of STN 32758A ? SOUTH UNIONVILLE & McCOWAN DISTRICT (MARKHAM) from 40psi to 55psi and raise pressure of STN 36013A ? MCCOWAN & SOUTHDALE DISTRICT from 50psi to 55psi
Related Programs and BCs: N/A

Compliance: N

Solution Description:

Scope of Work: 2021: Install XHP to HP station at Steeles Ave and IBM. The station will have a designed inlet of 485psi with an outlet of 175psi. The primary feed for this station will come from Victoria Gate. The tie?in for the inlet will be off of the NPS 30 SC and the outlet will feed into the NPS 12 ST HP on Steeles Ave. Approx. 25m for the inlet and 25m for the outlet will be required. 2022: Raise STN 36013A ? MCCOWAN & SOUTHDALE DISTRICT from 40psi to 50psi 2024: Install 1.4km of NPS 12 SC main on Tapscott Ave from Passmore Ave to Steeles Ave 2024: Raise pressure of STN 32758A ? SOUTH UNIONVILLE & McCOWAN DISTRICT (MARKHAM) from 40psi to 55psi and raise pressure of STN 36013A ? MCCOWAN & SOUTHDALE DISTRICT from 50psi to 55psi.

Resources: Construction contractor crews and Operations crews.

Solution Impact: Ability to maintain minimum required system pressure, maintain capacity, and meet customer demand.

Project Timing and Execution Risks: This project is to be initiated by Planning in 2019 (2 years in advance of construction start)since it would be a Leave to Construction Project. The first phase completed by the winter of 2021. The second phase is to be completed in 2024. Identified risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	401,940	$2,997,610	190
Option 2		401,940	$2,997,610	190
Option 3		84,302	$533,523	223
Option 4		334,557	$2,404,087	197

Asset Class: Pipe

Estimate Class: Class 5

Business Case ID:7710

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$30,000	$533,522	$60,000	$0	$2,374,087	$0	$0	$0	$0	$0	$2,997,610
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$30,000	$533,522	$60,000	$0	$2,374,087	$0	$0	$0	$0	$0	$2,997,610
Retirement Cost											
Total Project Cost	$30,000	$533,522	$60,000	$0	$2,374,087	$0	$0	$0	$0	$0	$2,997,610

Asset Class: Pipe **Business Case ID:**7710

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7710

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:2458

Estimate Class: Class 5

Project Information

Name: Peterborough Reinforcement

Type: Enbridge Project

Start Year: 2019

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need:

- Customer growth data coupled with Zoning Bylaw and Site Plan applications suggest that Network 4721 is expected to experience significant load growth.
- Station inlets at WOODLAND & CARNEGIE and 5TH LINE & WATER/LAKEFIELD will drop below minimum operating limits and growing demand northeast of Peterborough can't be supported. Pressure issue/concern: The minimum system pressure is forecasted to be infeasible by 2022. Customer growth issue/ concern: As of 2017, there are 25,142 customers on this network. Without reinforcement, forecasted 3,090 customers may not be able to be added.

Risk if not completed: There are ~800 residential and commercial customers (~1,860m3/h load addition) have been approved to add to the system by end of 2015. With these load additions, pressure at the end of the 400psig MOP XHP line at Fifth & Water in north of Peterborough
Assets (preferred option): 2.2km of NPS 8"ST-XHP along Preston Rd, from Maple Grove Rd to 600m-North of Mt. Pleasant Rd. Tie into existing 6"ST XHP-main on Trans Canada Hwy-7
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Install 2.2km of NPS 8"ST-XHP along Preston Rd, from Maple Grove Rd to 600m-North of Mt. Pleasant Rd. Tie into existing 6"ST XHP-main on Trans Canada Hwy-7
Resources: Construction contractor crews and Operations crews.
Solution Impact:
Project Benefits - The proposed reinforcement would increase station inlet pressures at WOODLAND & CARNEGIE and 5TH LINE & WATER/LAKEFIELD well above minimum operating limits - Security of supply would be increased for all the customers fed by the two district stations in the system; providing increased pressure support in the IP Network 4721 to allow for demand fluctuations as the area grows.
Project Timing and Execution Risks: LRP growth modeling indicates that the proposed reinforcement will be needed by end of year 2022 based on station inlets dropping below the minimum operating pressure of the system. Identified risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	185,935	$2,121,657	125

Asset Class: Pipe **Business Case ID:**2458

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$50,000	$2,071,657	$0	$0	$0	$0	$0	$0	$0	$0	$2,121,657
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$50,000	$2,071,657	$0	$0	$0	$0	$0	$0	$0	$0	$2,121,657
Retirement Cost	$0	$0									
Total Project Cost	$50,000	$2,071,657	$0	$0	$0	$0	$0	$0	$0	$0	$2,121,657

Asset Class: Pipe **Business Case ID:**2458

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**2458

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16751

Estimate Class:

Project Information

Name: Thornton XHP reinforcement

Type: Enbridge Project **Start Year:** 2022

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.
Project Purpose/ Need: Customer growth in the surrounding area will drive this reinforcement. Increase in load will cause tail end pressures to go below the minimum pressure of 100psi without reinforcement.
Risk if not completed: This reinforcement will limit the risk of customer loss up to forecast temperatures under normal operating conditions. Customer additions might be limited if this reinforcement is not completed.
Assets (preferred option):
? Phase 1 in 2022, Proposed 2.5 km of 12" SC XHP on Innisfil Beach Rd, from Thornton Gate Station #3613819 outlet to County Rd 53.
? Phase 2 in 2024 Proposed 6 km of 8" SC XHP on Lockhart Rd, from tail end of existing 8" SC XHP at Lockhart Rd/Yonge St to 25 Sideroad.
Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Phase 1 in 2022, Proposed 2.5 km of 12" SC XHP on Innisfil Beach Rd, from Thornton Gate Station #3613819 outlet to County Rd 53. - Phase 2 in 2024 Proposed 6 km of 8" SC XHP on Lockhart Rd, from tail end of existing 8" SC XHP at Lockhart Rd/Yonge St to 25 Sideroad.
Resources: Construction contractor crews and Operations crews.
Solution Impact: Project Benefits:
This reinforcement will allow continued customer additions in Innisfil, including Hewitt, Salems, Friday Harbour.
Project Timing & Execution Risks:
Phase 1 at 2022
Phase 2 at 2024
Identified risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

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Solution Options

OPTIONS				

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	600,882	$5,467,818	158

Asset Class: Pipe

Business Case ID: 16751

Estimate Class:

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$1,834,811	$3,633,007	$0	$0	$0	$0	$0	$0	$0	$0	$5,467,818
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,834,811	$3,633,007	$0	$0	$0	$0	$0	$0	$0	$0	$5,467,818
Retirement Cost	$44,707	$48,066									$92,773
Total Project Cost	$1,879,518	$3,681,073	$0	$0	$0	$0	$0	$0	$0	$0	$5,560,591

Asset Class: Pipe **Business Case ID:**16751

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**16751

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe

Business Case ID:7727

Estimate Class: Class 5

Project Information

Name: Welland IP NW8925 Reinforcement

Type: Enbridge Project

Start Year: 2019

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure to maintain the capacity to meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers. Project Purpose/ Need:

- Pressure at the east tail end will be low with the customer growth in this IP network.
- Customer growth in this IP network in the east section need more feeds to support.

Pressure issue/concern: The minimum system pressure is forecasted to be infeasible by 2020. Customer growth issue/ concern: As of 2017, there are 568 customers on this network. Without reinforcement, forecasted 105 customers may not be able to be added.
Risk if not completed: System Risk without this Reinforcement:

- Low pressure at the tail end of the network. Specifically, there are two nodes being fed from station 891740 and 89040 which are single fed. - Reinforcement in 2020 will allow tail end pressure to be above minimum of 10psi
- Without reinforcement, unable to add more customers to the network - there will be approximately 595 customers connected to this network by 2020 Assets (preferred option): - 1.3km of 4” PE IP on Lyons Creek Rd/Mathews Rd, from node 89250011 to 89250315 - 800m of 4” PE IP on Lyons Creek Rd, from node 89250309 to 89250301 - Station#89174A upgrade - 1.7km of 4” PE IP on Ridge Rd, from Doans Ridge Rd to McKenney Rd, from node 89250378 to 89250400.

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: 1.3km of 4” PE IP on Lyons Creek Rd/Mathews Rd, from node 89250011 to 89250315. And 800m of 4” PE IP on Lyons Creek Rd, from node 89250309 to 89250301. And Station#89174A upgrade. And 1.7km of 4” PE IP on Ridge Rd, from Doans Ridge Rd to McKenney Rd, from node 89250378 to 89250400
Resources: Construction contractor crews and Operations crews.
Solution Impact: Project Benefits:
Customer growth benefit: with reinforcement, This proposed reinforcement could raise the east tail end pressure while supporting the future customer growth in the IP network 8925 in Welland, and make sure it can support the next 10 years’ growth after the reinforcement in 2020.
Project Timing and Execution Risks: Reinforcement is proposed to be completed by year 2020. Identified risks: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	17,941	$2,501,458	10

Asset Class: Pipe **Business Case ID:**7727

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$1,669,305	$832,152	$0	$0	$0	$0	$0	$0	$0	$0	$2,501,458
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,669,305	$832,152	$0	$0	$0	$0	$0	$0	$0	$0	$2,501,458
Retirement Cost	$534,398	$267,199									$801,596
Total Project Cost	$2,203,703	$1,099,351	$0	$0	$0	$0	$0	$0	$0	$0	$3,303,054

Asset Class: Pipe **Business Case ID:**7727

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**7727

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**1213
Estimate Class: Class 5

Project Information

Name: York Region Reinforcement

Type: Enbridge Project **Start Year:** 2017

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement

Issue/Concern: Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.
Assets: A combination of Pipe and Station Assets to meet the project objectives.
Related Programs/Business Cases: N/A

Compliance: N
Solution Description:
Scope of Work
Pipeline installation will originate from Bathurst Gate Station (Bathurst Street and Gamble Avenue) and will terminate at Bathurst Street and Mulock Drive. Approximately 6.5km of NPS16 and will be installed on Bathurst Street and end at Bathurst Street and Bloomington Road. At this point it will reduce to an NPS12 and will continue 8.5km on Bathurst Street and terminate at Mulock Drive. The total proposed pipeline will be approximately 15km. Approximate estimate for future construction phase $30,000,000. In addition to the 15km of pipeline installation, 4 pressure cut stations will be required, 2 IP locations will be severed, including a section of the IP main.

2018: Rebuild Glenwoods & Woodbine Station (3546065) so that it has a differential of 35 psi or less. 2018: Rebuild Doane & Woodbine Station (2937273) so it has a differential of 50 psi or less and can handle the existing capacity.
2019: Install 2.1 km 4" XHP on Civic Centre Rd from Baseline Rd to 200m south of Metro Rd N.
2022: Install 5.4 km of 12" XHP starting at Bondhead Gate station and replace the existing 6" XHP all the way to the intersection of Hwy 88 and 10th Line. This may result in the requirement for a rebuild of Bondhead Gate Station for capacity reasons, pending confirmation of the maximum station throughput.
2024: Install 4.0 km 6" XHP on Baseline Road from McCowan Road to Dalton Road, north along Dalton Road to Black River Road, east along Black River Road to Station 3872873
2026: Install 7.6 km 12" XHP on Bathurst Street from Gamble Road to McClellan Way. Install 7.1 km 8" SC XHP on Bathurst from McClellan Way to Mulock Drive. Install 1 XHP to HP station at Bathurst Street and Bloomington Road.
2026: IP à HP pressure elevation must be completed. Elevate IP to HP New District Stations:
• 1 XHP to HP station at Bathurst Street and Mulock Road
• 1 HP to IP station at Bathurst Street and William Dunn Crescent
• 1 HP to IP station at Mulock Drive and Yonge Sever IP locations
• Bathurst Street and Keith Avenue
• Mulock Drive and Columbus Way
Elevate IP to HP:
• NPS12, NPS8, NPS4 and NPS2 main – approximately 7km
• Main located on Bathurst Street, Mulock Drive, 19th Sideroad and Old Bathurst Street
If the engineering assessment indicates that the IP cannot be elevated to HP then the following must be completed

instead:
• Install 1.7 km 8” SCs XHP on Mulock Dr from Bathurst St to Yonge St.
• Install XHP?HP station at Bathurst & Mulock.
• Install HP?IP station at Yonge & Mulock.
Resources: Construction contractor crews and Operations crews.
Solution Impact: Ability to maintain minimum required system pressure, maintain capacity, and meet customer demand.
Project Timing & Execution Risks: This project started in 2017. Identified risks are: The Long Range Plan is determined based on the best available information at the time of the plan, and is subject to change. If there are changes to the forecasted number of customer additions, or changes in the location of the forecasted growth, the Long Range Plan will be updated to reflect these changes

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,567,434	$68,368,000	53
Option 2	N	2,345,696	$52,018,000	63
Option 3		2,454,117	$59,498,000	58

Asset Class: Pipe **Business Case ID:**1213

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$0	$0	**$2,522,000**	**$70,000**	$2,656,000	$15,400,000	**$280,000**	**$6,260,000**	$1,280,000	$39,900,000	$68,368,000
Rebillable Amount	$0	$0	**$0**	**$0**	$0	$0	**$0**	**$0**	$0	$0	
Net Direct Capital Cost	$0	$0	**$2,522,000**	**$70,000**	$2,656,000	$15,400,000	**$280,000**	**$6,260,000**	$1,280,000	$39,900,000	$68,368,000
Retirement Cost	$0										
Total Project Cost	$0	$0	**$2,522,000**	**$70,000**	$2,656,000	$15,400,000	**$280,000**	**$6,260,000**	$1,280,000	$39,900,000	$68,368,000

Note:

The capital spend that is reflected in EGD's Asset Management Plan for this project totals $9.132M for years 2019, 2020, 2023, and 2024 (see the numbers in bold in the above table). All other costs are associated with the portion of the solution that is currently under development (see Section 6.3).

Asset Class: Pipe **Business Case ID:**1213

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**1213

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R1	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Appendix 7.2-3 – Stations Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Stations **Business Case ID:**1700
Estimate Class: Class 5

Project Information

Name: BLACKHORSE GATE

Type: Enbridge Project **Start Year:** 2019

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

Blackhorse Gate Station is located on an EGD-owned property of approximately 1,500 m2 fenced compound in Welland, Ontario (approximately 10 km west of Niagara Falls, On.), within a rural area, in close proximity to five residential homes, a motel and a small business. This station accepts natural gas from TCPL and provides supply to four separate XHP networks, two NPS 12, one NPS 6, and one NPS 8 IP outlet. The station consists of gas measurement, pressure control, a gas preheat system, an odourant injection system, and a telemetry system. This station supplies natural gas to approximately 65,000 customers in Niagara region. The following issues have been identified at this station:
Compliance: An engineering assessment of the site layout has identified a conflict with the location of the telemetry or boiler Buildings with respect to the ESA Area Classification requirements which has identified that an ignition source is in close proximity to a potential leak source, as defined within the Electrical Codes and Standards.
Measurement: The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redundancy to the existing measurement and improved response capabilities. The meter was installed in 2002, and has been identified for replacement.
Heating: The three existing boilers at this site are at least 20 years old, they have had trouble call/failures over the recent years, including failures of the motors and pumps, burner lock-outs and exchanger failures. The heat exchanger is to be replaced, along with the boilers and their building, by a CWT system.
Pressure Control: The regulation system contains obsolete components (Welker Jets) which are difficult and costly to work on, and parts are difficult to obtain when repairs are required. The two other stations that feed two other outlets are double-boot, posing an undesired higher risk and high associated ongoing maintenance costs.
Odourization: The odourant injection system is a combination of Link and Wilroy Pumps which are located in a separate building from the tank. The pump building has no containment for a leak. The tank sits in a steel “dog house” -type shed which will have to be replaced with a functional building with proper containment, and ancillary equipment including fire suppression, and gas detection. The current configuration of the odourant system does does not meet the current engineering standards and approvals.
Telemetry and Electrical: The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement, and gas chromatograph installation. The existing RTU building and the room off of the regulator building are expected to be sufficient for the work proposed. A new RTU building is required.
Integrity: The two existing 400psi outlets have been identified as potential >30%SMYS lines. Currently, there are no provisions for launchers. As part of the rebuild, ensure provisions to make these outlets inline inspection-ready.
Asset: Blackhorse Gate Station assets.
Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work:
Pipes & Valves: All valves and piping will be replaced to accommodate a new layout.
Heating System: The existing heating system will be removed and replaced with two new CWT units outside of any

hazardous area.
Pressure Control: All regulators will be replaced and a new building will be installed with methane detection. The existing boot-style regulators will be replaced with new regulators sized to handle the future projected load. Jet control valves will be replaced with new Becker control valves.
Odourant System: The entire odourant system will be replaced with a new system meeting design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and CGIs.
Telemetry and Electrical: The undersized RTU building will be replaced with a new building. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator, modem and firewall upgrades, station lighting upgrades, and weather station installation. New inlet and outlet metering will also be installed.
Measurement: A second metering run will be installed to accurately measure all flow conditions to address any metering discrepancies and provide better data for the odourant injection rate. The existing meter will be replaced with properly sized mass flow meters.
Compliance & Others: N/A
Solution Impact: Improved station reliability that meets code requirements, with capacity for current demands and future gas forecasts.
Resources: Company crews, contractor labour and third-party vendor suppliers.
Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2
Execution Risk Weather impacts, resource availability, procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	631,396	$3,633,653	244

Asset Class: Stations

Business Case ID:1700

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$1,200,000	$2,433,653	$0	$0	$0	$0	$0	$0	$0	$0	$3,633,653
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,200,000	$2,433,653	$0	$0	$0	$0	$0	$0	$0	$0	$3,633,653
Retirement Cost		$182,114									$182,114
Total Project Cost	$1,200,000	$2,615,767	$0	$0	$0	$0	$0	$0	$0	$0	$3,815,767

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**1700

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R1	R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1			R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations | **Business Case ID:**7749
Estimate Class: Class 5

Project Information

Name: BOWMANVILLE GATE

Type: Enbridge Project | **Start Year:** 2024

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

Bowmanville Gate Station is located on a fenced property owned by EGD, of approximately 700 square meters in the Clarington, Ontario. It is approximately 5 km north of Newcastle Ontario, within a rural area. This station accepts natural gas from TCPL and provides supply to two separate XHP networks, through a measurement system, pressure control system, gas pre heat system, odourant injection system, and telemetry and controls system. This station supplies natural gas to approximately 61,000 customers in an area that spans from Bowmanville to Lindsay.
The following issues have been identified at this station:
Valves and Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves, however, the valves have deteriorated to the point where the reliability is no longer acceptable. The inlet piping to the heat exchanger shows signs of deterioration and should be replaced. The station is located close to Hwy 35/115 and its proximity to traffic puts it at a higher risk. The piping is to be relocated away from the road, as practical as possible.
Measurement: The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides redundancy to the existing measurement, odourant injection reliability, and improved response capabilities. The turbine meter is to be replaced with a Coriolis meter.
Heating: The existing boilers at this site are 18 years old, they have had 42 trouble call/failures over the life of the heating system, including failures of the motors and pumps, burner lock-outs and exchanger failures. The system, including buildings, will require replacement as it approaches end-of-life.
Odourization: The odourant system was installed in 1999. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. The building is an old style, rusted “dog house” and a new building, tank, and odourant injection system will be required.
Telemetry and Electrical: The existing electrical system does not meet current EGD electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.
OTHER: Odourant deliveries - a third-party company is used for traffic control during deliveries. Additional land, not included in this business case may be identified under a separate business case for station expansion to improve safety during odourant deliveries off of Hwy 35/115.
Asset: Bowmanville gate station assets.
Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work:
Pipes & Valves: Excessive station piping will be shortened and/or removed and the inlet to the heat exchangers will be replaced. The valves will have to be replaced.
Heating System: The boilers will have to be replaced due to their age and a new heating system, including glycol piping will have to be sized to accommodate future load and installed. The boiler building will also be relocated to an area outside of any hazardous areas.
Pressure Control: The existing double boot-style regulators will be replaced with new regulators sized to handle the future projected load.
Odourant System: The entire odourant system will be replaced with a new system meeting design standards. The

new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and CGIs.
Telemetry and Electrical: The telemetry and electrical systems will be brought up to current standards and may include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement, and gas chromatograph installation are also required.
Measurement: The existing turbine meter will be replaced with mass-flow meters and redundant annubar meters on both outlets.
Compliance & Others: Additional land, not included in this business case may be identified under a separate business case for station expansion to improve safety during odourant deliveries off of Hwy 35/115.
Solution Impact: Improved station reliability that meets code requirements, with capacity for current demands and future gas forecasts.
Resources: Company crews, contractor labour and third-party vendor suppliers.
Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2.
Execution Risk - Weather impacts, resource availability, procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	137,547	$3,247,557	60

Asset Class: Stations **Business Case ID:**7749

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$1,905,580	$1,341,977	$0	$0	$0	$0	$0	$0	$0	$0	$3,247,557
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,905,580	$1,341,977	$0	$0	$0	$0	$0	$0	$0	$0	$3,247,557
Retirement Cost		$147,012									$147,012
Total Project Cost	$1,905,580	$1,488,989	$0	$0	$0	$0	$0	$0	$0	$0	$3,394,569

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:** 7749

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3608

Estimate Class: Class 5

Project Information

Name: BROCKVILLE GATE

Type: Enbridge Project **Start Year:** 2024

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

Brockville Gate Station is located on EGDowned property approximately 5 km from the town of Brockville, Ontario. This station accepts natural gas from TCPL and provides supply to two separate XHP networks. Station components include measurement, gas preheat system, pressure regulation, odourant injection and a telemetry system. This station supplies natural gas to approximately 19,463 customers in Brockville region. The following issues have been identified at this station:

Compliance: An engineering assessment of the site layout has identified a conflict with the location of the telemetry or boiler Buildings with respect to the ESA Area Classification. The assessment identified improperly rated equipment operating in a classified area as defined by the Canadian Electrical Code.

Valves and Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Valve maintenance has been unable to remediate the problem and the valves have deteriorated to the point where the reliability is no longer acceptable. All valves will have to be replaced.

Heating: The existing boilers at this site are 18 years old, they have had several trouble call/failures over the recent years, including failures of the motors and pumps, burner lock-outs and exchanger failures. While the boilers are being replaced this year (2018), the glycol tank and heat exchanger will need to be replaced and relocated to meet ESA requirements mentioned above.

Pressure Control: The regulator station have boot-style regulators posing an undesired higher risk and high associated ongoing maintenance costs. Engineering has identified that boot-style regulators operating as both monitor and operating regulators is unacceptable. The regulator runs will have to be rebuilt.

Odourziation: The odourant system was installed in 2000. A new odourant building will have to be installed to ensure adequate containment in the event of a leak. The injection pumps are located in the regulator room and will have to be relocated into the odourant building to meet current standards.

Telemetry and Electrical: The RTU building is undersized and needs replacement to accommodate adequate working space for employees and equipment. Improperly rated electrical equipment is installed and operating in electrical hazardous areas and the layout will have to be redesigned.

Asset: Brockville gate station assets.

Related Program:N/A

Compliance: Y

Solution Description:

Scope of Work:

Piping & Valves: Replace all valves including station isolation valves and bypass valves. Station piping will have to be rebuilt to accommodate a new layout.

Heating System: Replace glycol piping and heat exchanger.

Pressure Control: The existing double boot-style regulators will be replaced with new regulators sized to handle the future projected load.

Odourant System: The entire odourant system will be replaced with a new system meeting current design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and secondary containment.

Telemetry and Electrical: The undersized RTU building will be replaced with a new building. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and

monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement, and gas chromatograph installation are also required.
Measurement: The existing flow meters will be replaced with a mass-flow meter and two back up annubars, one on each outlet.
Compliance & Others: Resolution with Area Classification conflicts is required.
Solution Impact: Improved station reliability that meets code requirements, with capacity for current demands and future gas forecasts.
Resources: Company crews, contractor labour and third-party vendor suppliers.
Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2.
Execution Risk - Weather impacts, resource availability, procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	107,270	$2,774,489	55

Asset Class: Stations **Business Case ID:**3608

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$2,774,489	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,774,489
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,774,489	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,774,489
Retirement Cost		$189,636									$189,636
Total Project Cost	$2,774,489	$189,636	$0	$0	$0	$0	$0	$0	$0	$0	$2,964,125

Asset Class: Stations **Business Case ID:**3608

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3608

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations | **Business Case ID:**13384

Estimate Class: Class 5

Project Information

Name: Campbell St District Stn relocate

Type: Enbridge Project | **Start Year:** 2020

Asset Program: Gate & Feeder Station

Project Type: Station Replacement Program

Issue/Concern:

Campbell St. District station receives XHP (400 psi) gas and regulates it to 30psi. A boiler and heat exchanger system preheats the gas. This station is at the end of the Barrie to Collingwood NPS 8 line and ILI inspection requires a receiver installed. The current location of the Campbell St. station has a receiver which is too small to accommodate the smart tools that the Integrity department wishes to use. Additional operational room is required to remove pigs from the receiver and there is no room for parking on site to support current operations. The surrounding property is too close to contain the hazardous area created from the piping. The station is to be relocated to an appropriate-sized lease.
Asset: Campbell St District Station assets.
Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work:

Permanent relocation of station to a location upstream from current location of at least 30mx40m In this option:
• A new station will be rebuilt in the new location to meet current and future flows.
• 280m of NPS 6 ST IP main extension is required to tie back the outlet of the station to the existing IP network.
• The section of NPS 8 XHP downstream of the new station location will NOT be replaced and will be inspected using a crawler tool. Inspection using crawler tool would impact the O&M budget of approx. $200,000 every seven-year cycle (or whenever this pipeline needs to be inspected). Refer to attached document (Scenario D) for the breakdown of the cost estimate.
Resources: Company crews and/or contractors
Solution Impact: Ability to run Enbridge standard tools for ILI of pipelines.
Project Timing and Execution Risks: Meeting regulatory required ILI intervals.:

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	290,491	$3,933,089	112
Option 2		290,636	$4,105,174	108

Asset Class: Stations

Business Case ID:13384

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$1,930,820	$2,002,269	$0	$0	$0	$0	$0	$0	$0	$0	$3,933,089
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,930,820	$2,002,269	$0	$0	$0	$0	$0	$0	$0	$0	$3,933,089
Retirement Cost											
Total Project Cost	$1,930,820	$2,002,269	$0	$0	$0	$0	$0	$0	$0	$0	$3,933,089

Asset Class: Stations **Business Case ID:**13384

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3612

Estimate Class: Class 5

Project Information

Name: LISGAR GATE

Type: Enbridge Project **Start Year:** 2022

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

Lisgar Gate Station is located on Enbridge owned property of approximately 12,700 m2 fenced compound in Mississauga, Ontario. It sits in a heavily developed area of both residential and commercial buildings including the Meadowvale Town Center, approximately 500 m away, and it is directly adjacent to a community church, a small commercial plaza, and several residential detached homes. This station accepts natural gas from Union Gas and provides supply to 2 separate XHP feeds, 1 HP supply and 1 IP supply. This station is a major supply point for the NPS 24 NEB regulated pipeline and the NPS 20 which feeds Mississauga, Etobicoke, and loops supply to downtown Toronto.

The natural gas supplied from Union Gas is measured, heated, regulated down to XHP and is odourized. This station also includes piping to move gas back and forth from the NPS 24 and NPS 20 pipelines which provide operational flexibility for gas supply. Lisgar is also the principle feed for the NPS 30 line that feeds Mississauga, Malton, Signet, Downsview and ends at Keele and Steeles. The following issues have been identified at this station:

Valves & Piping: The existing valves at this site have experienced issues in performance and operation. Valve maintenance has not resolved their performance issues and the valves have deteriorated to the point where their ability to isolate is unreliable. The NPS 30 outlet valve needs to be replaced as it is leaking. All copper tubing currently used as sense lines in underground conduit runs is to be replaced. The Shaeffer actuator sits on an unknown bypass valve that was purchased along with the NPS 24 from TCPL. This valve and actuator also needs to be replaced as it is as the actuator has no operational manuals for maintenance. The crossover valve from the NPS 20 and NPS 30 line must be replaced as operations cannot operate the valve. This is a single above ground valve separating two pressure classes that is undersized. When gas flows through this valve have caused noise complaints from surrounding residences.

Underground piping is original and its integrity is unconfirmed.

Measurement: The current system has older style pitot tube measurement on the four outlets. The station has no inlet measurement and we rely on Union Gas measurement for odourization. Redundant measurement is standard for odourization that is required when gas is supplied by Union Gas.

Heating: Four boilers are used in the gas preheat system upstream of regulation and currently one boiler is non-operational. These boilers are 18 years old and are approaching end of life. The boiler location is within an area classification to which they are not rated. The boilers need replacement and relocation. Glycol filtration was installed in 2017. The 3 way valves on the glycol system experience operational issues because of the deteriorating quality of the glycol. The heat exchanger is also in need of replacement as it is located in a basement that is subject to flooding when the sump pumps have failed. The water sump pumps are in a confined space. The glycol pumps are also located in a basement which is accessible by ladder only. All glycol piping will have to be replaced.

Pressure Control: The regulation station that receives gas from Union needs to be replaced as it has an old style NPS 6 control valves without any remote operation, an NPS 8 has flow control only, and an NPS 12 old pressure controller which is unreliable. All regulators at the Union inlet must be replaced. The isolation valves leak and also must be replaced. The regulators that feed the NPS 20 and NPS 30 are relatively new and do not need replacement. The regulator building has settled and will require some civil work. The district station has older axial flow regulators that have experience frost heave and are to be replaced.

Odourization: The odourant system was installed in 2012. The current configuration of the odourant system does

not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. Building replacement is required. The Odourant pumps that exist require redundant runs added to ensure odourization.
Telemetry & Electrical: The existing electrical system does not meet current EGD electrical installation standards and extensive electrical work will have to be completed. Generator install is required at this site as the existing generator installed in 1999 has caused noise complaints from neighbours. The RTU is an old 3330 and requires replacement. A new tower installation, card swipe security access installation (though this is a combined site that which is also accessed Union), Methane Monitoring, CO sensor and monitoring, ESA Compliance Issues, Station wiring, Electrical service Upgrade, Station Grounding, Inlet Flow Meter, Outlet Flow meter upgrading.

Asset: Lisgar Gate Station
Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work:
Pipes & Valves: Replace station isolation valves with new and reliable Cameron ball valves. All station piping and valves will be examined to ensure that material specifications and their current condition are acceptable for continued use. Projected future station capacity requirements will also be considered.
Heating System: Replace the boilers and heat exchanger. Boiler piping will also have to be replaced to match up with the new boilers and heat exchanger. The boilers are at end of life and require replacement. The glycol piping will have to be repiped to the new boilers and the building replaced to accommodate. Relocation of the boilers will require a new building.
Pressure Control: There are three different stations at Lisgar and the regulator station that receives gas from Union will have to be replaced including their isolation valves. The other two regulator stations that feed the NPS 20 and NPS 30 are relatively new and do not need replacement. A new Regulator building will have to be installed for security and public optics as this is a heavily congested and well trafficked area. Odourant System: The existing odourant tank will have to have a new odourant building that will include sufficient secondary containment which is not installed at the current station. A new odourant tank will also be required, along with a second backup injection system to serve as redundancy to the first.
Telemetry & Electrical: The existing RTU cabinet and panel will be replaced with a new Control Wave unit. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement.
Measurement: New measurement will be installed on the inlet from Union Gas and updated measurement will be included on the three outlet lines of the station. This will measure flow out of the NPS 24, NPS 20, and NPS 12. Piping will be designed to ensure gas measurement when operationally flowing from the NPS 24 to the NPS 20 and reverse.
Compliance & Others: Sump pumps will be replaced/relocated to remove them from the confined space. Pending decision of the Union Gas and EGD merger, the odourant system may be decommissioned.

Solution Impact: The station will meet current EGD standards and will close the existing compliance gaps for an efficient facility with suitable controls installed for Gas Control.

Resources: Company Crews, Contractor Labour and 3rd Party vendor suppliers

Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2 / Execution Risk - Weather impacts, Resource availability, Procurement, etc.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	103,060	$4,940,178	30

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:3612

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$2,593,599	$2,346,579	$0	$0	$0	$0	$0	$0	$0	$0	$4,940,178
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,593,599	$2,346,579	$0	$0	$0	$0	$0	$0	$0	$0	$4,940,178
Retirement Cost		$277,596									$277,596
Total Project Cost	$2,593,599	$2,624,175	$0	$0	$0	$0	$0	$0	$0	$0	$5,217,774

Asset Class: Stations **Business Case ID:**3612

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations
Estimate Class: Class 5

Business Case ID:1013

Project Information

Name: MARKHAM GATE

Type: Enbridge Project

Start Year: 2023

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

Markham Gate Station is located on an EGDowned fenced compound in Markham, Ontario, approximately 15km from the town of Markham, within a rural/urban area, in close proximity to Greensborough. This station accepts natural gas from TCPL and provides supply to two separate XHP networks, through components within the measurement system, pressure control system, hating system, odourant system, and telemetry system. This station supplies natural gas to approximately 110,000 customers in York region. The following issues have been identified at this station:
Compliance: An engineering assessment of the site layout has identified a conflict with the location of the telemetry or boiler Buildings with respect to the ESA Area Classification requirements which has identified that an ignition source is in close proximity to a potential leak source, as defined within the Electrical Codes and Standards.
Valves and Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves, however, the valves have deteriorated to the point where the reliability is no longer acceptable. Three NPS 16 outlet valves were reused from Parkway rebuild and do not lock up. These will have to be replaced.
Measurement System: The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redudancy to the existing measurement required for odourant injection and improved response capabilities. Currently, the north outlet is measured and flow on the south outlet is subtracted from the inlet measurement. Low flow is not registered on the inlet meter when only the north flow is running. Under this operation, odourant injection needs to be manually adjusted.
Heating: The existing boilers at this site are 15 years old, they have had four trouble call/failures over the recent years, including failures of the motors and pumps, burner lock-outs and exchanger failures. Due to recent and upcoming customer growth in the Markham area, the existing heating system will not be capable of supplying the heating requirements to meet the demand. The existing tin building and boilers will have to be replaced. The existing heat exchanger is not anticipated to require replacement.
Pressure Control: The regulation system is undersized and not capable of supplying the demand required to meet the customer growth in the Markham area. The north outlet is fed by two three-inch double boot regulators which will have to be replaced to eliminate the undesired risk of the double boot and associated ongoing maintenance costs. The south outlet requires replacement of one EZR regulator.
Odourization System: The odourant system was installed in 2009. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. The odourant injection system will be moved into a new building. A new tank will be required.
Telemetry and Electrical: The existing electrical system does not meet current EGD electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications.
Asset: Markham gate station assets
Related Program:N/A

Compliance: Y
Solution Description:
Scope of Work:
Piping and Valves: The three existing NPS 16 station outlet valves will be replaced with new Cameron ball valves

along with the bypass valves and inlet valves.
Heating System: The existing heating system will be replaced with new boilers and a new boiler building outside of any hazardous areas.
Pressure Control: New regulator runs will have to be installed on the north outlet regulator station.Tthe south outlet regulator station only requires replacement of one EZR regulator.
Odourant System: The entire odourant system will be replaced with a new system, tank, injection system and building that meets current design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and CGIs.
Telemetry and Electrical: The undersized RTU building will be replaced with a new building. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator upgrade, modem and firewall upgrades, station lighting upgrades, and weather station installation/replacement are also required.
Measurement: A new outlet meter will be installed on the south outlet and the inlet meter will be replaced to accommodate required future capacity.
Compliance & Others: Fence repairs are also required at this site.
Solution Impact: Improved station reliability that meets code requirements, with capacity for current demands and future gas forecasts.
Resources: Company crews, contractor labour and third-party vendor suppliers.
Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2.
Execution Risk - Weather impacts, resource availability, procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	20,405	$2,941,519	10

Asset Class: Stations **Business Case ID:**1013

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$1,480,274	$1,461,245	$0	$0	$0	$0	$0	$0	$0	$0	$2,941,519
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,480,274	$1,461,245	$0	$0	$0	$0	$0	$0	$0	$0	$2,941,519
Retirement Cost		$188,241									$188,241
Total Project Cost	$1,480,274	$1,649,486	$0	$0	$0	$0	$0	$0	$0	$0	$3,129,760

Asset Class: Stations **Business Case ID:**1013

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**1013

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3620
Estimate Class: Class 5

Project Information

Name: MOUNTAIN RD GATE

Type: Enbridge Project **Start Year:** 2028

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:
Mountain Road Gate Station is located on EGD- owned property of approximately 1800 square meters in a fenced compound in Niagara Falls, Ontario, approximately 10 km from Niagara Falls, within a rural/urban area. This station accepts natural gas from TCPL and provides supply to one NPS 12 XHP network (Glendale) network, one NPS 12 HP (Dorchester) network, and one NPS 8 IP network (Lundy's Lane). The gate station includes a measurement system, pressure control system, heating system, odourant system, and telemetry system. This station supplies natural gas to approximately 85,700 customers in the Niagara region. The following issues have been identified at this station:
Valves and Piping: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves, however, the valves have deteriorated to the point where the reliability is no longer acceptable. Valve actuators have been installed on the outlet valves and heat exchanger isolation and bypass valves but programming is required to control the actuators with the RTU. Valves are all original valves installed during the installation of the gate station (approximately 30 years).
Measurement: The inlet is metered by a relatively new NPS 12 ultrasonic meter (approximately 10 years). The current system does not provide measurement of the individual outlet supplies. Visibility to each outlet supply provides greater redudancy to the existing measurement and improved response capabilities. Outlet metering is to be connected to SCADA and visible to theGas Control group.
Heating: Three existing boilers at this site are old boilers, approximately 20 years old, they have had 10 trouble call/failures over the recent years, including failures of the motors and pumps, burner lock-outs and exchanger failures. The existing heat exchanger was installed in 1995 and will be at end-of-life by the rebuild date. Due to recent and upcoming customer growth in the Niagara Falls area, the existing heating system will not be capable of supplying the heating requirements to meet the demand. Fuel gas station to the boilers is metered but conversion of the generator from diesel to natural gas will require it to be upsized.
Pressure Control: The configuration of the existing regulators are all boot-style regulators, posing an undesired higher risk and high associated ongoing maintenance costs. The regulators will have to be replaced.
Odourization: The odourant injection system is a combination of Link and Wilroy Pumps which are located in a separate building from the tank. The pump building has no containment for a leak. The tank sits in a steel "dog house" -type shed which will have to be replaced with a functional building with proper containment, and ancillary equipment including fire suppression, and gas detection. The current configuration of the odourant system does does not meet the current engineering standards and approvals.
Telemetry and Electrical: The existing electrical system does not meet current EGD electrical installation standards. This poses a potential electrical hazard and faulty wiring may result in lost communications. A new RTU building will be required to upgrade the control room to current standards. The RTU has recently replaced recently (2016) and rewiring will have to be done to install it into an RTU building. The existing generator is an old diesel generator and will be replaced with a new natural gas generator.
Asset: Mountain Road Gate station assets.
Related Program: N/A

Compliance: Y
Solution Description:

Scope of Work:
Pipes & Valves: The previously -nstalled actuators will be integrated and tied-in. Outlet valves are to be replaced. Fuel gas system to the boilers (CWT) and new generator will have to be rebuilt.
Heating System: The existing heating system will be removed and replaced with two CWT units outside of any hazardous area to appropriately provide sufficient heat and redundancy. One CWT will be dedicated to the IP outlet and the other for the two outlets.
Pressure Control: The existing double boot-style regulators will be replaced with new regulators sized to handle the future projected load.
Odourant System: The entire odourant system will be replaced with a new system meeting design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and CGIs.
Telemetry and Electrical: The telemetry and electrical systems will be brought up to current standards and may include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator upgrades, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement, and gas chromatograph installation. The existing RTU building and the room off of the regulator building are expected to be sufficient for the work proposed. No new RTU building is identified as required.
Measurement: Secondary measurement will be installed on all three outlets and tied into the RTU and SCADA system so that the outlets are visible to gas control.
Compliance & Others: None identified.
Solution Impact: Improved station reliability that meets code requirements, with capacity for current demands and future gas forecasts.
Resources: Company crews, contractor labour and third-party vendor suppliers
Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2.
Execution Risk - Weather impacts, resource availability, procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	21,419	$3,268,071	10

Asset Class: Stations **Business Case ID:**3620

Estimate Class: Class 5

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$3,268,071	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,268,071
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,268,071	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,268,071
Retirement Cost		$209,537									$209,537
Total Project Cost	$3,268,071	$209,537	$0	$0	$0	$0	$0	$0	$0	$0	$3,477,608

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**7753
Estimate Class: Class 5

Project Information

Name: NOBLETON GATE

Type: Enbridge Project **Start Year:** 2024

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:
Nobleton Gate Station is located on a fenced in, EGDowned property of approx 1,000 square meters in the City of Vaughan, Ontario, approximately 3 km from the Town of Nobleton, within a rural area. This station accepts natural gas from TCPL and provides supply to an XHP network, with a measurement system, pressure control system, heating system, odourant system, and a telemetry and controls system. This station supplies natural gas to approximately 1800 customers in the Bolton and King City areas. The following issues have been identified at this station:
Compliance: An engineering assessment of the site layout has identified a conflict with the location of the telemetry and boiler buildings with respect to the ESA area classification requirements which has identified that an ignition source is in close proximity to a potential leak source, as defined within the Electrical Codes and Standards. Additional property will be required to remediate the area classification issue.
Measurement: Gas measurement is completed using a turbine meter installed in 2004. This meter type has experienced failures causing potential downstream impacts and loss of service to customers. This meter has experience six failures in the past two years, due to leaks and faulty measurement. A new mass flow meter will be installed to replace the turbine meter and a backup outlet annubar meter will also be installed.
Heating: The existing boilers at this site are 14 years old, they have had three trouble call/failures over the past year, including failures of the motors and pumps, burner lock-outs and exchanger failures. The boilers, building, and glycol piping require replacement as they will be will be 20 years old by the target rebuild date. The heat exchanger is not expected to be replaced but inspection is to be included.
Pressure Control: The regulators are the original regulators installed when the station was first commissioned. In 2001, a building was installed over them to improve maintenance and operation. The regulators have experienced 29 trouble calls/failures in the time period, including leaks, boot failures, and pilot failures. Both monitor and operator runs are boot-style regulators, which poses an undesired higher risk and high associated ongoing maintenance costs.
Odourization: The odourant system was installed in 2004, with the injection system installed in 2009. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak and does not meet the current engineering standards and approvals. The panel will have to be relocated into a new building with a larger new tank.
Telemetry and Electrical: The existing electrical system does not meet current EGD electrical installation standards and there are area classification issues that need be resolved. The wiring poses a potential electrical hazard and faulty wiring may result in lost communications.
Other: Programming as required.
Asset: Nobleton Gate Station assets.
Related Program:N/A

Compliance: Y

Solution Description:

Scope of Work:
Piping andValves: No issues have been identified with the valves but the area classification remediation will require rebuild of the piping. Reuse of valves is an option for cost efficiency but construction efforts may not deem this as feasible.

Heating System: New boilers, building and glycol piping will have to be built to replace the boilers and address the area classification issue. The existing expansion tank will be replaced during the boiler building relocation to remove the building from any hazardous area. This expansion will require additional property.
Pressure Control: Axial flow regulators will be replaced with new regulators sized to handle future projected load. This will eliminate the vulnerability of having both monitor and operator as boot-style regulators.
Odourant System: The entire odourant system will be replaced with a new system meeting design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and CGIs.
Telemetry and Electrical: The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, modem and firewall upgrades, station lighting upgrades, weather station, and installation/replacement are also required.
Measurement: The existing turbine meter will be replaced with a properly sized ultrasonic or mass-flow meter. Redundant annubar measurement will be installed on the outlet to reinforce odourant injection rates.
Compliance & Others: Required programming for the new equipment is also required. A looping line to the NPS 24 pipe would provide reinforcement to the network. This may be the best cost effective way of accomplishing redundancy supply to the NPS 24 pipe.
Solution Impact: Improved station reliability that meets code requirements, with capacity for current demands and future gas forecasts.
Resources: Company crews, Contractor labour and third-party vendor suppliers.
Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2.
Execution Risk - Weather impacts, resource availability, procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	55,660	$2,179,536	35

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:7753

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$1,070,805	$1,108,731	$0	$0	$0	$0	$0	$0	$0	$0	$2,179,536
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,070,805	$1,108,731	$0	$0	$0	$0	$0	$0	$0	$0	$2,179,536
Retirement Cost		$150,707									$150,707
Total Project Cost	$1,070,805	$1,259,438	$0	$0	$0	$0	$0	$0	$0	$0	$2,330,243

Asset Class: Stations **Business Case ID:**7753

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**7753

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**1031

Estimate Class: Class 3

Project Information

Name: ORO-MEDONTE GATE

Type: Enbridge Project **Start Year:** 2018

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

Oro-Medonte Gate Station is located on EGD- owned property of approximately 1,800 m2 fenced compound in the Township of Oro-Medonte, Ontario, in a rural area north of Barrie. This station accepts gas from TCPL and provides supply to the XHP network, through components within the measurement system, pressure control, heating system, odourant system, and telemetry system. This station supplies natural gas to approximately 10,000 customers in Barrie and Oro-Medonte Township.
The following issues have been identified at this station:
Piping and Valve: The piping configuration does not facilitate the proper maintenance procedures to complete the compliance inspection requirements of the components at this site. This causes non-standard procedures to be used for maintenance activities, with the potential for errors to occur.
Heating System: The existing heating system is 12 years old, and has experienced failures and maintenance issues. The existing boiler building is in a state disrepair, with leaks and ongoing repair requirements.
Odourization: The odourant system was installed 2003 with a 200-gallon odourant tank. Over the past 10 years, there have been seven trouble calls, due to leaks or increased maintenance calls due to vapour locks or leaks found in the system, and a complete system failure. The current configuration of the odourant system does not ensure adequate containment of the odourant product in the event of a leak.
Measurement: The existing Turbine meter was installed in 2004. We have experienced numerous meter inaccuracy issues due to large fluctuations in seasonal changes, and significant maintenance costs due to the inspection requirements.
TELEMETRY & ELECTRICAL: The telemetry and electrical systems do not meet current EGD standards, the existing generator and backup power supply were installed in 2000 and are approaching end of useful life. The existing RTU is obsolete and is required to be upgraded to current components along with new communications equipment in order to eliminate cyber security threats
Asset: Oro-Medonte Gate station assets.
Related Program: N/A

Compliance: Y

Solution Description:

Oro-Medonte Gate Boiler System, Odourant System and Boiler Building Replacement
Decommissioning BOiler, HExchanger, glycol piping, flare burner, odourant tank & injection equipment, inlet filter.
Civil Work
install in CWT,
FROM DBM: The existing boilers and heat exchanger systems are approaching end of asset life.
The existing condensing boilers present a compliance non-conformance as the condensate is not treated prior to release to ground.
The Odourant system does not have appropriate containment and requires upgrades
The measurement at the gate station requires replacement and a redundant meter to support odourization.x
Inlet area piping does not have built in bypass around the filter and meter
RTU upgrade to Control Wave Micro.
New Generator install.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	8,030	$2,037,321	5

Asset Class: Stations

Business Case ID: 1031

Estimate Class: Class 3

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$342,654	$1,064,449	$630,218	$0	$0	$0	$0	$0	$0	$0	$2,037,321
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$342,654	$1,064,449	$630,218	$0	$0	$0	$0	$0	$0	$0	$2,037,321
Retirement Cost			$102,198								$102,198
Total Project Cost	$342,654	$1,064,449	$732,416	$0	$0	$0	$0	$0	$0	$0	$2,139,519

Asset Class: Stations **Business Case ID:**1031

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**1031

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**9741
Estimate Class: Class 5

Project Information

Name: PARKWAY GATE

Type: Enbridge Project **Start Year:** 2022

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:
Pipe and Valves: Large diameter valves are difficult to operate manually. Actuators are to be installed on all large diameter valves to allow for easier operation.There is no permanent pig launcher for the MSL. A new pig launcher is scheduled to be installed in 2019.

Heating System: Replace Boilers & Building as the current grade and elevations causes flooding in the boiler building. Water pools under the electrical service to the building and creates unnecessary hazards. Replace obsolete Delta V boiler control system with current Honeywell controllers. Replace manual 3 way valves & actuators in heating system. 3 way valves have been difficult to operate in glycol service. Glycol piping will have to be replaced to accommodate new actuated 3 way valves.
The Heat Exchangers were inspected in 2017 and there was no immediate concern to indicate that they would need replacement. However, they are not equipped with catch pans for catching any glycol solutions should there be a leak and containment pans are to be installed.
Pressure Control: One Becker control valve is defective and not locking up and repair is planned for 2018. This is to be completed as part of trigger spend in 2018 and is completed under Business Case 19629. New DNGP pilot actuators are to be installed on new operating regulators are to be replaced. Two flow control valves from TCPL leak and isolation is required. This can be achieved by actuating the run valves so that Gas Control can confidently shut in the regulator station.
Odourant: Odourant is contained in two separate old dog house style buildings and requires replacement with a new odourant building. The existing building currently doesn't have combustible gas detection and the concrete pad is in need of replacement. Fire suppression system was never installed and will be required. Additional required upgrades include a new injection panel and new tanks. Separate injection panels will have to be replaced. One odourizes the NPS 36 MSL and the other odourizes the NPS 36 Parkway North line.
Telemetry/Electrical: Replace old 3330 RTU to upgrade to a new Control Wave unit with a new modem and firewall that will allow for control of the regulator runs and optimization of gas supply to the GTA. A new RTU building will have to be installed to alleviate area classification issues. The instruments inside the room adjacent to the RTU room are to be relocated directly onto the pipe to eliminate the runs of sense lines across the lease. The station will have to be rewired with to accommodate the new instrument locations.
The communication tower will have to be replaced to meet CSA standards as it is not equipped with an anti-climb device or an appropriate caged ladder.
The existing emergency generator set is undersized and outdated for the intended application per current EGD Standards and a corresponding UPS system will also be needed for installation (Note: 600VAC 3-Phase power (Milton Hydro) is available at this site). The electrical service will have to be upgraded to accommodate the increased electrical load.
The fuel gas supply to the emergency generator and boilers are metered but it requires a second duplicate regulator run to allow for proper redundancy should the primary run fail to operate.
Methane and CO sensing and monitoring will have to be installed where appropriate. Additional electrical work includes installation of a station grounding network, station lighting upgrade, and a weather station.

Measurement: The NPS 30 ultrasonic flowmeters that feeds the MSL has had discrepancies between this meter

and the flow data from the custody-transfer USM in the Union Gas facility next door. The off-axis 90-degree elbows may also have caused excess swirls on the gas stream going through this meter and the meter runs and their piping is to be replaced. Inlet measurement is required for the Union connection but the inlet from TCPL is metered.
Existing station flowmeters are not of custody-transfer quality meters.
Check accuracy of the existing USMs with respect to summer flowrates. Inaccuracy of the meters may cause odorization issues during warm summer days

Compliance and Other: Relocate Boiler building due to hazardous area compliance issues. Sources of ignition are inside the hazardous areas of existing block valves, fittings, and equipment. This is a non-compliant condition per the Canadian Electrical Code and EGD Standards.
Considerations should be given to replace station piping that corroded and/or having combined stress of 30% SMYS or greater.
There is no urethane layer between the pipe support cradle and the bottom of the pipe leaving the pipe susceptible to corrosion.
Asset: Parkway Gate Station
Related Program: N/A

Compliance: Y
Solution Description:

Scope of Work:

Pipes & Valves: All station piping and valves will be examined to ensure that material specifications and their current condition are acceptable for continued use. Projected future station capacity requirements will also be considered for sizing. Actuators will be installed as this site to allow for more efficient use of the facility by Gas Control.

Heating System: The boiler building needs to be replaced and relocated outside of any hazardous areas. New boilers are to be installed with new boiler controls. New glycol piping will have to be installed to accommodate the new boilers.
Secondary containment for the heat exchangers are required as part of the heating system overhaul. The obsolete Delta V controller will be replaced with new Honeywell controllers.

Pressure Control: The existing control valves will be replaced with properly sized Becker Control Valves complete with a combination of Jordan motor and DNGP controls.

Odourant System: The entire odourant system will be replaced with a new system meeting design standards. The new odourant building will contain both the tank and injection panel, complete with containment, fire suppression system, and instrumentation.

Telemetry & Electrical: The existing RTU cabinet and panel will be replaced with a new Control Wave unit. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator, modem and firewall upgrades, station lighting upgrades, weather station installation/replacement, and gas chromatograph installation.

Measurement: Installation of two new NPS 30 ultrasonic meters to address any volumetric discrepancies.

Compliance & Others: Programming as required.

Solution Impact: Station risk will be reduced by closing compliance gaps and by bringing the station up to current EGD standards.

Resources:
Company Crews, Contractor Labour and 3rd Party vendor suppliers

Project Timing & Execution Risk:
Planning in Year 1, Execution in Year 2 / Execution Risk - Weather impacts, Resource availability, Procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	123,529	$4,063,794	45

Asset Class: Stations **Business Case ID:**9741

Estimate Class: Class 5

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$1,966,132	$2,097,662	$0	$0	$0	$0	$0	$0	$0	$0	$4,063,794
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,966,132	$2,097,662	$0	$0	$0	$0	$0	$0	$0	$0	$4,063,794
Retirement Cost		$292,341									$292,341
Total Project Cost	$1,966,132	$2,390,003	$0	$0	$0	$0	$0	$0	$0	$0	$4,356,135

Asset Class: Stations **Business Case ID:**9741

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**9741

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8567

Estimate Class: Class 5

Project Information

Name: STJOHN SIDEROAD FEEDER

Type: Enbridge Project **Start Year:** 2018

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:
The property on which St. John's Sideroad Feeder station currently sits is insufficient for operation. It is located adjacent to residential property and the area classification extends onto the adjacent private property. The boiler building is located in a hazardous area classification and the non-compliance needs to be remedied. Road widening of St. John's Sideroad currently has the sidewalk encroaching on our station. A land sale agreement with York Region was completed in 2016 and requires movement of the electrical meter. As the area classification issue risks shutdown of the station by the Electrical Safety Authority, EGD is postponing the movement of the electrical meter (onsite) pending a new land purchase for relocation of the entire station. As a result of station relocation, a complete rebuild will be required. Maintenance on the boiler system piping, pumps and gauges, which are old and obsolete, suggest that the heating system needs to be replaced regardless of station relocation. The heating system is already undersized for the current demand. The FL regulators are difficult to work on due to their weight and the ergonomic restriction in a cramped building. These are to be replaced and upgraded. The old RTU 3330 telemetry system needs to be upgraded, including the backup power generator which is old and obsolete. Station updated in 2006. Generator installed in 2003. Boilers installed in 2003. Source records does not indicate capacity issue with regulators.

Asset: Stn ID: 2944180.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work:
A new station and all supporting infrastructure will be constructed on a newly acquired parcel of land. The existing station will be removed from service and abandoned appropriately.
The new location will be in close proximity to the existing station just off of St. John's Sideroad, East of Leslie and West of the 404.
Pipes & Valves: All existing piping will have to be built as part of the station relocation. This includes station isolation and bypass valves as well as isolation valves required for the heating system and regulator runs. A new fuel gas station will be required that includes measurement of fuel gas consumption by the boilers and the generator.
Heating System: A new boiler and heat exchanger type heating system will have to be installed for gas preheat and all area classification requirements will be met.
Pressure Control: New regulator runs will have to be installed as the existing FL regulators are difficult to maintain.
Odourant System: No odourant system is required as this is a Feeder Station.
Telemetry & Electrical: The existing RTU panel will be replaced with a new unit in a new electrical building to meet area classification requirements. A new RTU cabinet and panel will be replaced with a Control Wave unit. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator installation, modem and firewall upgrades, station lighting upgrades, and weather station installation/replacement.
Measurement: A new mass flow meter will be installed and connected to SCADA so that Gas Control can monitor station flows, pressures, and temperatures.

Compliance & Others: New land will have to be acquired to allow for the station relocation and there are currently two sites that are favoured. Either of these options will require significant civil work to ensure a suitable grade on which the station will sit and allow for adequate run off capabilities. The new station will require additional XHP and HP pipe to be installed to connect appropriately to the existing network. The location will determine the length of pipe needed to be installed.
$2 million allotment for Land acquisition.
Solution Impact: TBD
Resources: Company Crews, Contractor Labour and 3rd Party vendor suppliers
Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2 / Execution Risk - Weather impacts, Resource availability, Procurement, etc.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	N	27,903	$4,421,959	9
Option 2	Y	30,413	$5,669,370	8

Asset Class: Stations **Business Case ID:**8567

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$10,000	$1,000,000	$4,659,370	$0	$0	$0	$0	$0	$0	$0	$5,669,370
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,000	$1,000,000	$4,659,370	$0	$0	$0	$0	$0	$0	$0	$5,669,370
Retirement Cost		$184,559									$184,559
Total Project Cost	$10,000	$1,184,559	$4,659,370	$0	$0	$0	$0	$0	$0	$0	$5,853,929

Asset Class: Stations **Business Case ID:**8567

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years				R2			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years		R2					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations

Business Case ID:8567

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R2				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R2					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3584
Estimate Class: Class 5

Project Information

Name: 2019 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2019

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	718,802	$6,500,000	185

Asset Class: Stations

Business Case ID:3584

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$6,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000

Asset Class: Stations **Business Case ID:** 3584

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3584

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3585

Estimate Class:

Project Information

Name: 2020 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2020

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	646,147	$6,500,000	160

Asset Class: Stations

Business Case ID:3585

Estimate Class:

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$6,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000

Asset Class: Stations **Business Case ID:**3585

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3585

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3586
Estimate Class: Class 5

Project Information

Name: 2021 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2021

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	309,033	$7,000,000	123

Asset Class: Stations

Business Case ID:3586

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,000,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$8,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,000,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0	R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3586

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0	R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8935

Estimate Class: Class 5

Project Information

Name: 2022 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2022

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	520,567	$7,500,000	109

Asset Class: Stations **Business Case ID:**8935

Estimate Class: Class 5

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000

Asset Class: Stations **Business Case ID:**8935

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8935

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10241

Estimate Class: Class 5

Project Information

Name: 2023 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2023

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	241,993	$7,500,000	55

Asset Class: Stations **Business Case ID:**10241

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10296
Estimate Class: Class 5

Project Information

Name: 2024 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2024

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	607,577	$7,500,000	131

Asset Class: Stations

Business Case ID:10296

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000

Asset Class: Stations **Business Case ID:**10296

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10296

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10297

Estimate Class: Class 5

Project Information

Name: 2025 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2025

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors with 3rd party vendors for equipment supply.
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	607,577	$7,500,000	131

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:10297

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000

Asset Class: Stations **Business Case ID:**10297

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10298
Estimate Class: Class 5

Project Information

Name: 2026 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2026

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	607,577	$7,500,000	131

Asset Class: Stations **Business Case ID:**10298

Estimate Class: Class 5

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000

Asset Class: Stations **Business Case ID:**10298

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:10299

Project Information

Name: 2027 District Station Rebuilds Program

Type: Enbridge Program

Start Year: 2027

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	607,577	$7,500,000	131

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:10299

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$7,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000

Asset Class: Stations **Business Case ID:**10299

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10299

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**16434

Estimate Class: Class 5

Project Information

Name: 2028 District Station Rebuilds Program

Type: Enbridge Program **Start Year:** 2028

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

The stations identified in this business case fall into one of the following categories:
Below-ground box replacements: Removal of below-ground stations improves life cycle cost of stations due to accelerated corrosion related to salting and flooding, increased O&M costs related to increased paint frequency, and the requirement for two at a box when work is performed. An additional and very important benefit to the elimination of below-ground boxes is the improvement of worker health and safety by eliminating the need to handle potentially contaminated water, and non-ergonomic work conditions.
Obsolete Regulators: The criteria for this category is that there are no spare parts available, or parts are no longer approved for use on new installations, or a combination of poor performance and manufacturer availability.
Low Pressure Districts: The failure of a low pressure district can have disastrous downstream impacts in the event of over-pressure protection failure. The outlets of these stations feed customers who may not have individual regulators at their meter sets. This additional line of defense is not present to protect customer piping.
Double Boot-style Regulators: Stations with both operator and monitor boot-style regulators have a common failure mechanism as a result of debris in the gas stream. Replacement of one boot-style regulator with a non-boot regulator reduces the vulnerability of failure.
Increased Capacity: Stations that are operating over designed capacity due to system growth are targeted for replacement to maintain gas supply.
Loss of Containment: Station experiencing loss of containment (leaks) and high maintenance calls to repair equipment are also identified for replacement.
Asset: District station assets
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The District Station Rebuild Program strategy is to maintain a consistent operational reliability profile and requires the replacement of approximately 20 to 30 district stations per year, based on condition assessments and component obsolescence/age. Each station replacement in a given year will require a complete rebuild including the removal and replacement of the pressure control components, valves, associated piping, and enclosure. The duration of a typical district station rebuild project is approximately six months, which includes design, permitting, procurement, execution, and site restoration activities.
Resources: Internal resources, company crews and/or Contractors
Solution Impact: Maintain operationally reliable and safe district stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	607,577	$8,500,000	115

Asset Class: Stations **Business Case ID:**16434

Estimate Class: Class 5

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$8,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,500,000
Retirement Cost	$1,000,000										$1,000,000
Total Project Cost	$9,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,500,000

Asset Class: Stations **Business Case ID:**16434

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1	R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**16434

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3581

Estimate Class:

Project Information

Name: 2021 Sales stations rebuilds

Type: Enbridge Program **Start Year:** 2021

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:

Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.

Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.

Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.

Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact aligment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.

Asset: Sales station assets.

Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of sales station rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations. Project
Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	81,313	$2,000,000	60

Asset Class: Stations **Business Case ID:**3581

Estimate Class:

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost	$600,000										$600,000
Total Project Cost	$2,600,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,600,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3581

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8937
Estimate Class: Class 5

Project Information

Name: 2022 Sales stations rebuilds

Type: Enbridge Program **Start Year:** 2022

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:
Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.
Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.
Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.
Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact aligment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.
Asset: Sales station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of sales station rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations. Project
Timing and Execution Risks: Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	92,929	$2,035,000	68

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:8937

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$2,035,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,035,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,035,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,035,000
Retirement Cost	$615,000										$615,000
Total Project Cost	$2,650,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,650,000

Asset Class: Stations **Business Case ID:**8937

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8937

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations
Estimate Class: Class 5

Business Case ID:9844

Project Information

Name: 2023 Sales stations rebuilds

Type: Enbridge Program

Start Year: 2023

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:
Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.
Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.
Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.
Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact aligment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.
Asset: Sales station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of sales station rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	81,313	$2,070,613	58

Asset Class: Stations

Business Case ID:9844

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$2,070,613	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,070,613
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,070,613	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,070,613
Retirement Cost	$620,000										$620,000
Total Project Cost	$2,690,613	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,690,613

Asset Class: Stations **Business Case ID:**9844

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**9844

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10303
Estimate Class: Class 5

Project Information

Name: 2024 Sales stations rebuilds

Type: Enbridge Program **Start Year:** 2024

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:
Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.
Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.
Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.
Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact alignment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.
Asset: Sales station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of sales station rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	64,718	$2,106,848	46

Asset Class: Stations

Business Case ID:10303

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$2,106,848	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,106,848
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,106,848	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,106,848
Retirement Cost	$630,000										$630,000
Total Project Cost	$2,736,848	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,736,848

Asset Class: Stations **Business Case ID:**10303

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10304
Estimate Class: Class 5

Project Information

Name: 2025 Sales stations rebuilds

Type: Enbridge Program **Start Year:** 2025

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:
Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.
Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.
Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.
Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact alignment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.
Asset: Sales station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of sales station rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	96,248	$2,143,718	67

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:10304

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$2,143,718	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,143,718
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,143,718	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,143,718
Retirement Cost	$650,000										$650,000
Total Project Cost	$2,793,718	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,793,718

Asset Class: Stations **Business Case ID:**10304

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10304

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10361
Estimate Class: Class 5

Project Information

Name: 2026 Sales stations rebuilds

Type: Enbridge Program **Start Year:** 2026

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:
Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.
Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.
Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.
Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact alignment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.
Asset: Sales station assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of sales station rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	73,016	$2,181,233	50

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:10361

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$2,181,233	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,181,233
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,181,233	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,181,233
Retirement Cost	$660,000										$660,000
Total Project Cost	$2,841,233	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,841,233

Asset Class: Stations **Business Case ID:**10361

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10361

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**10362
Estimate Class: Class 5

Project Information

Name: 2027 Sales stations rebuilds

Type: Enbridge Program **Start Year:** 2027

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:
Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.
Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.
Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.
Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact aligment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.
Asset: Sales station assets.
Related Program:N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of salesstation rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	81,313	$2,219,405	54

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:10362

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$2,219,405	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,219,405
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,219,405	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,219,405
Retirement Cost	$670,000										$670,000
Total Project Cost	$2,889,405	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,889,405

Asset Class: Stations **Business Case ID:** 10362

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**16433
Estimate Class: Class 5

Project Information

Name: 2028 Sales stations rebuilds

Type: Enbridge Program **Start Year:** 2028

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

Sales Stations are the final pressure control point prior to entering into a customer's building. Operational failure of a sales station such as loss of containment can lead to an explosion or fire. Some factors included in this risk category are damage to property, injuries to members of the public, and the cost to repair the damaged assets. Over-pressure at a sales station can lead to over-pressure in the customer piping system, causing potential leaks in the downstream system or inside customer premises. This could result in consequences of ignition within the customer's property. Under-pressure at a sales station can lead to loss of service for customers, which is particularly a problem if the gas is used for process, home heating, or for life safety generators. The Sales Station Rebuild Program Strategy is to continuously inspect, collect information and remediate assets with the following issues:
Non-conforming installations: The design or configuration of some sales stations does not allow for required maintenance work (compliance work) to be completed without customer interruptions. Installation practices have evolved such that an older station may require a rebuild to ensure operational integrity. Design or configuration of a sales station may not allow for required maintenance work (compliance work) to be completed without customer interruptions.
Obsolete parts: The failure of obsolete regulators would cause excessive delay to repair since parts are not readily available. This could lead to a disruption in service and may impact the safe and reliable delivery of natural gas to customers.
Unsafe installation locations: Stations may be exposed to the elements, located in potentially hazardous locations, lack proper clearances and be susceptible to potential threats from third-party damages. Development and encroachment may also increase the risk of a sales station. Any of these issues could result in a rebuild.
Integrity of a station: A station may be subject to corrosion and degrading paint and pipe coating due to age or environment may decrease the integrity of the piping and components. The effects of time and/or frost heaving can impact alignment that may cause a station to be rebuilt. Based on the historical replacement rate of the sales station population, and comparing to the condition assessment findings, it is expected that the replacement rate should increase as part of the Asset Plan. The Sales Station Rebuild Program will target approximately 100 stations per year to address the issues above.
Asset: Sales Stations assets.
Related Program:N/A

Compliance: N

Solution Description:

Scope of Work: Prioritization of sales station rebuilds will be in accordance with condition assessment reviews, Asset Health Review projections, and risk assessments. Currently, approximately 100 stations have been identified with condition issues in need of remediation. Projects within the Sales Station Rebuild Program will target stations that require rebuilding based on location, condition, age, and obsolescence. The Sales Station Rebuild Program will focus on a complete rebuild of the station site, which includes the removal and replacement of the pressure control components, valves, and associated piping. Some projects may require the station to be relocated. Operational reliability is based on asset condition improvements and the ability to operate safely, but does not preclude consideration of an asset's early retirement because of obsolescence. The Sales Station Rebuild Program will be to maintain consistent operational reliability profile through the duration of the Asset Plan.

Resources: Company crews, contractor labour and third-party vendor suppliers.
Solution Impact: Maintain operationally reliable and safe sales stations.
Project Timing and Execution Risks:Specific to each child project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	64,718	$2,258,244	42

POWERPLAN AMP

Asset Class: Stations **Business Case ID:**16433

Estimate Class: Class 5

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$2,258,244	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,258,244
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,258,244	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,258,244
Retirement Cost	$680,000										$680,000
Total Project Cost	$2,938,244	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,938,244

Asset Class: Stations **Business Case ID:**16433

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R1	R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**1261
Estimate Class: Class 5

Project Information

Name: ERR Program

Type: Enbridge Program **Start Year:** 2016

Asset Program: Inside Regulator Program

Project Type: Integrity Mitigation - Distribution

Issue/Concern:

Inside Regulators pose a public safety risk within our distribution system and to our customers' properties. A regulator serves the main purpose of reducing the system pressure prior to the customer's piping and distribution throughout the customer's property. Having these regulators located inside a building poses an increased risk because a loss of containment at or upstream of the regulator due to third-party damage or regulator malfunction which could potentially release IP gas into the building, resulting in a high consequence event. Inside regulators could potentially cause adverse downstream pressures (over-pressures) to customer piping if the regulator vent to the exterior becomes blocked or degraded. Received Risk Director approval for an initial $5M in 2015 ($2M for Area 10, $2M for Area 60, $0.2M for Area 40, and $0.8M already approved) out of the total estimate of $18.6M.
Asset: Inside Regulators and ERRs
Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: The scope of work includes the relocation of remaining inside regulator stations and low pressure sets to outside locations for all areas.
Year 3 (2018) $500,000 for continuing ERR remediation.
• Continue with enclosures for the inside regulator stations committed to in 2015 / 2016. This amounts to a total spend of $1,008,500.00 for Eastern Region in 2017.
• Defer two enclosures for the inside regulator station which willhave yet to be confirmed for 2018. The planned spend is $48,500.00 for 171 Slater St. and 230 Queen St. in 2018.
• Defer all work on ERR’s to 2018. At present, the planned spend estimated for this work is $57,500.00. Quotes were requested to remediate 50 Rideau St., 215 Slater St., 150 Elgin St. and 180 Wellington St.; these are not currently included in the $57,500.00 required in 2018. To summarize, theestimated spend for 2017 will be $1,008,500.00, and have agreed to defer $106,000 to 2018. There will be extra costs estimated for 2018 once the quotes are received for the four ERR’s recently identified.
Resources: Company crews and Contractors.
Solution Impact: Reduced risk of inside regulators.
Project Timing and Execution Risks: Access to privately owned property

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Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI

Option 1	Y	0	$4,000,004	0

Asset Class: Stations

Estimate Class: Class 5

Business Case ID:1261

Cost

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Direct Capital Cost	$2	$2	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$4,000,004
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2	$2	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$4,000,004
Retirement Cost	$65,000										$65,000
Total Project Cost	$65,002	$2	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$4,065,004

Asset Class: Stations **Business Case ID:**1261

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8144

Estimate Class: Class 5

Project Information

Name: Integrity Stations Retrofit Program > 30% SMYS

Type: Enbridge Program **Start Year:** 2017

Asset Program: Integrity Initiatives - Stations

Project Type: Integrity Retrofit

Issue/Concern:

Funds to install or to retrofit temporary launcher or receiver within Station facilities to allow for in-line inspection (ILI). This will allow in-line inspection of the pipeline required as per the Pipeline Integrity Management Program. This project is part of the Gas Storage and Transmission System (GSTS) integrity management plan that satisfies the requirements of the Pipeline Integrity Management Program mandated by CSA Z662-11 Clauses 3.2 and 10.3.10 as audited by the TSSA. These features are compliance-driven items that must be completed as part of the program.

Asset: Launchers and Receivers within Station facilities.

Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Install ILI launchers and receivers at selected station sites where ILI runs have been identified. A decision was made to install permanent launchers and receivers at any station site. The justification to switch from temporary to permanent launchers and receivers is due to lack of records of temporary facilities, loss of material between temporary uses, damages occurring during transit of facilities between temporary jobs and poor maintenance and upkeep. The decision was also made based on the Ottawa Gate Station launcher incident in 2014-2015.

Resources: Internal resources, company crews and/or Contractors

Solution Impact: Permanent launchers and receivers at station sites installed at either end of the pipeline to allow for in-line inspection of the which is required as per the Pipeline Integrity Management Program.

Project Timing and Execution Risks: Timing to required to accommodate ILI runs on pipelines.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	73,395	$9,984,183	11

Asset Class: Stations **Business Case ID:**8144

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$2	$1,012,947	$2,573,483	$1,850,374	$1,197,377	$1,500,000	$1,400,000	$450,000	$0	$0	$9,984,183
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2	$1,012,947	$2,573,483	$1,850,374	$1,197,377	$1,500,000	$1,400,000	$450,000	$0	$0	$9,984,183
Retirement Cost											
Total Project Cost	$2	$1,012,947	$2,573,483	$1,850,374	$1,197,377	$1,500,000	$1,400,000	$450,000	$0	$0	$9,984,183

Asset Class: Stations **Business Case ID:**8144

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years				R1			
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years	R1						
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8144

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years				R1			
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years				R1			
Once in 100000 to 1000000 years							

Appendix 7.2-4 – Storage Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Storage **Business Case ID:**12957
Estimate Class: Class 5

Project Information

Name: SCOR:100MOD Hdr Valves-Replace

Type: Enbridge Project **Start Year:** 2020

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Operations have identified compressor station yard isolation valves that do not provide sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Valve condition is under investigation in the Asset Health Review. Condition assessment results are rudimentary. Leaking valve seals are not necessarily valves that leak to atmosphere or pose a loss of containment threat. The valves referenced in this business case are those that allow gas to flow, when in the closed position. These leaking valves pose: (i) a process safety threat (ii) a loss of system performance by creating recycle loops; and (iii) decreased ability to provide a safe work environment for maintenance activities that require double lock and bleed. If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of overpressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe.
Asset: ¼ Turn Isolation valves . There are dozens of these valves in service.
Related Programs/BCs: Not Applicable

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost assumes that all MOD valves on the Transmission Header will be replaced. There are a total of 23 valves - all valves are PN100 pressure classification. It is assumed that valves sizes match the size of the Transmission Header (NPS24). Valves include: 66101-MV-014; 66101-MV-007; 66102-MV-014; 66102-MV-007; 66103-MV-014; 66103-MV-007; 66104-MV-014; 66104-MV-007; 66105-MV-014; 66105-MV-007; 66106-MV-014; 66106-MV-007; 66107-MV-014; 66107-MV-007; 66108-MV-014; 66108-MV-007; 66109-MV-014; 66109-MV-007; 66110-MV-014; 66110-MV-007; 66111-MV-014; 66111-MV-007; 132-MV-034. The project targets a specified header to replace all associated MOD valves. Work includes design, stakeholder consultations, retaining a construction contractor, prefabricating piping, hydrotesting at shop, laying plates, isolate system likely with a full station outage, cut out existing valves, installing supports as required, install new piping coating as required, NDE, energize system and remediating site.
Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety External Resources: Engineering Firm, Site Inspector, Construction Contractor and Sub-contractors, Non-Destructive Testing contractor, Survey contractor, Concrete Testing/Ground Testing contractor, Community Engagement, Environmental.
Solution Impact: Replacing the valves with new valves will stop leakage issues. This ensures the MOD valves are capable of preventing mixing of gases at different pressures, directing gas as required and isolation can be obtained when required.
Risks Reduced:
(1) Safety - leaking valves can result in safety risks for all staff and contractors. In addition leakage can result in damage to infrastructure in the event of ignition
(2) Infrastructure reliability - Leakage or can interfere with the operation of the facility if valves are required for purposes such as over pressure protection. In the event that separate MOPS can not be kept isolated, derating of systems may be required having significant impacts pending the point in the injection/withdrawal cycle
(3) Performance degradation. Leaking valves create recycle loops that reduce the effectiveness of compression. *

Project Timing and Execution Risks: Planning and Execution in Year 1: Execution Risk such as unavailability of the yard, weather, and injection/withdrawal schedule. The project impacts a crucial area of plant which can affect or be affected by numerous systems.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	489,958	$5,218,230	106

Asset Class: Storage **Business Case ID:**12957

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$100,000	$5,118,230	$0	$0	$0	$0	$0	$0	$0	$0	$5,218,230
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$100,000	$5,118,230	$0	$0	$0	$0	$0	$0	$0	$0	$5,218,230
Retirement Cost											
Total Project Cost	$100,000	$5,118,230	$0	$0	$0	$0	$0	$0	$0	$0	$5,218,230

Asset Class: Storage **Business Case ID:**12957

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**12957

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**12958
Estimate Class: Class 5

Project Information

Name: SCOR:100MOD Hdr Valves-Replace

Type: Enbridge Project **Start Year:** 2021

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Operations have identified compressor station yard isolation valves that do not have sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Valve condition is under investigation in the Asset Health Review. Condition assessment results are rudimentary. Leaking valve seals are not necessarily valves that leak to atmosphere or pose a loss of containment threat. The valves referenced in this business case are those that allow gas to flow, when in the closed position. These leaking valves pose: (i) a process safety threat; (ii) a loss of system performance by creating recycle loops; and (iii) decreased ability to provide a safe work environment for maintenance activities that require double lock and bleed. If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency, will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of overpressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe.
Asset: ¼ Turn Isolation valves. There are dozens of these valves in service.
Related Programs/BCs: Not Applicable

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost assumes that all MOD valves on the MKC Header will be replaced. There are a total of 23 valves - all valves are of the PN100 pressure classification. It is assumed that valves sizes match the size of the MKC Header (NPS24). Valves include: 66101-MV-013; 66101-MV-006; 66102-MV-013; 66102-MV-006; 66103-MV-013; 66103-MV-006; 66104-MV-013; 66104-MV-006; 66105-MV-013; 66105-MV-006; 66106-MV-013; 66106-MV-006; 66107-MV-013; 66107-MV-006; 66108-MV-013; 66108-MV-006; 66109-MV-013; 66109-MV-006; 66110-MV-013; 66110-MV-006; 66111-MV-013; 66111-MV-006; 120-MV-032. The project targets a specified header to replace all associated MOD valves. Work includes design, stakeholder consultations, retaining a construction contractor, prefabricating piping, hydrotesting at shop, laying plates, isolating the system likely with a full station outage, cutting out existing valves, installing supports as required, installing new piping coating as required, NDE, energizing the system and remediating the site.
Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety.
External Resources: Engineering Firm, Site Inspector, Construction Contractor and sub-contractors, Non-Destructive Testing contractor, Survey contractor, Concrete Testing/Ground Testing contractor, Community Engagement, Environmental.
Solution Impact: Replacing the valves with new valves will stop leakage issues. This ensures the MOD valves are capable of preventing the mixing of gases at different pressures, directing gas as required and isolation can be obtained when required.
Risks Reduced:
(1) Safety - leaking valves can result in safety risks for all staff and contractors. Leakage can also result in damage to infrastructure in the event of ignition
(2) Infrastructure reliability - Leakage or can interfere with the operation of the facility if valves are required for purposes such as over pressure protection. In the event that separate MOPS can not be kept isolated, derating of

systems may be required, having significant impacts pending the point in the injection/withdrawal cycle
(3) Performance degradation. Leaking valves create recycle loops that reduce the effectiveness of compression.
Project Timing and Execution Risks: Planning and Execution in Year 1. Execution Risk such as unavailability of the yard, weather, and injection/withdrawal schedule. The project impacts a crucial area of plant which can affect or be affected by numerous systems.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	341,487	$3,866,880	100

Asset Class: Storage

Business Case ID:12958

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$100,000	$3,766,880	$0	$0	$0	$0	$0	$0	$0	$0	$3,866,880
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$100,000	$3,766,880	$0	$0	$0	$0	$0	$0	$0	$0	$3,866,880
Retirement Cost											
Total Project Cost	$100,000	$3,766,880	$0	$0	$0	$0	$0	$0	$0	$0	$3,866,880

Asset Class: Storage **Business Case ID:**12958

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**12958

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**12959
Estimate Class: Class 5

Project Information

Name: SCOR:100MOD Hdr Valves-Replace

Type: Enbridge Project **Start Year:** 2022

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Operations have identified compressor station yard isolation valves that do not provide sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Valve condition is under investigation in the Asset Health Review. Condition assessment results are rudimentary. Leaking valve seals are not necessarily valves that leak to the atmosphere or pose a loss of containment threat. The valves referenced in this business case are those that allow gas to flow, when in the closed position. These leaking valves pose: (i) a process safety threat; (ii) a loss of system performance by creating recycle loops; and (iii) decreased ability to provide a safe work environment for maintenance activities that require double lock and bleed. If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves leak, there is an increased threat of overpressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe.
Asset: ¼ Turn Isolation valves. There are dozens of these valves in service.
Related Programs/BCs: Not Applicable

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost assumes that all MOD valves on the SKC/WLK Header will be replaced. There are a total of 24 valves - all valves are of the PN100 pressure classification. It is assumed that valves sizes match the size of the SKC/WLK header (NPS20). Valves include: 66101-MV-015; 66101-MV-008; 66102-MV-015; 66102-MV-008; 66103-MV-015; 66103-MV-008; 66104-MV-015; 66104-MV-008; 66105-MV-015; 66105-MV-008; 66106-MV-015; 66106-MV-008; 66107-MV-015; 66107-MV-008; 66108-MV-015; 66108-MV-008; 66109-MV-015; 66109-MV-008; 66110-MV-015; 66110-MV-008; 66111-MV-015; 66111-MV-008; 120-MV-037; 120-MV-036. The project targets a specified header to replace all associated MOD valves. Work includes design, stakeholder consultations, retaining a construction contractor, prefabricating piping, hydrotesting at shop, laying plates, isolating the system likely with a full station outage, cutting out existing valves, installing supports as required, install new piping coating as required, NDE, energizing the system and remediating the site.
Resources: Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety
External Resources: Engineering Firm, Site Inspector, Construction Contractor and sub-contractors, Non-Destructive Testing contractor, Survey contractor, Concrete Testing/Ground Testing contractor, Community Engagement, Environmental.
Solution Impact: Replacing the valves with new valves will stop leakage issues, ensuring the MOD valves are capable of preventing the mixing of gases at different pressures, directing gas as required and isolation can be obtained when required.
Risks Reduced:
(1) Safety - leaking valves can result in safety risks for all staff and contractors and leakage can result in damage to infrastructure in the event of ignition.
(2) Infrastructure reliability - Leakage can interfere with the operation of the facility if valves are required for purposes such as over pressure protection. In the event that separate MOPS cannot be kept isolated, derating of systems may be required, having significant impacts pending the point in the injection/withdrawal cycle
(3) Performance degradation. Leaking valves create recycle loops that reduce the effectiveness of compression.

Project Timing and Execution Risks: Planning and Execution in Year 1. Execution Risk such as unavailability of the yard, weather, and injection/withdrawal schedule. The project impacts a crucial area of plant which can affect or be affected by numerous systems.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	369,897	$3,866,880	108

Asset Class: Storage **Business Case ID:**12959

Estimate Class: Class 5

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$100,000	$3,766,880	$0	$0	$0	$0	$0	$0	$0	$0	$3,866,880
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$100,000	$3,766,880	$0	$0	$0	$0	$0	$0	$0	$0	$3,866,880
Retirement Cost											
Total Project Cost	$100,000	$3,766,880	$0	$0	$0	$0	$0	$0	$0	$0	$3,866,880

Asset Class: Storage **Business Case ID:**12959

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**12959

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**12960
Estimate Class: Class 5

Project Information

Name: SCOR:100MOD Hdr Valves-Replace

Type: Enbridge Project **Start Year:** 2023

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Operations have identified compressor station yard isolation valves that do not have sufficient seal quality to provide isolation during normal maintenance activities or emergency situations. Valve condition is under investigation in the Asset Health Review. Condition assessment results are rudimentary. Leaking valve seals are not necessarily valves that leak to the atmosphere or pose a loss of containment threat. The valves referenced in this business case are those that allow gas to flow, when in the closed position.
These leaking valves pose: (i) a process safety threat; (ii) a loss of system performance by creating recycle loops; and (iii) decreased ability to provide a safe work environment for maintenance activities that require double lock and bleed. If valve condition is not maintained at a reasonable level, the ability to isolate assets during an emergency, will be compromised. Valves in question are sometimes used to separate piping with different MOPs. If these valves are allowed to leak, there is an increased threat of overpressuring lower MOP pipe as gas bleeds through the valve from higher MOP pipe.
Asset: ¼ Turn Isolation valves. There are dozens of these valves in service.
Related Programs/BCs: Not Applicable

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost assumes that all MOD valves on the SEC Header will be replaced. There are a total of 23 valves - all valves are of the PN100 pressure classification. It is assumed that valves sizes match the size of the SEC Header (NPS16). Valves include: 66101-MV-012; 66101-MV-005; 66102-MV-012; 66102-MV-005; 66103-MV-012; 66103-MV-005; 66104-MV-012; 66104-MV-005; 66105-MV-012; 66105-MV-005; 66106-MV-012; 66106-MV-005; 66107-MV-012; 66107-MV-005; 66108-MV-012; 66108-MV-005; 66109-MV-012; 66109-MV-005; 66110-MV-012; 66110-MV-005; 66111-MV-012; 66111-MV-005; 120-MV-033.
The project targets a specified header to replace all associated MOD valves. Work includes design, stakeholder consultations, retaining a construction contractor, prefabricating piping, hydrotesting at shop, laying plates, isolating system likely with a full station outage, cutting out existing valves, installing supports as required, install new piping coating as required, NDE, energizing system and remediating site.
Resources:
Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir Group, Instrument and Electrical, Operations, Execution, Finance, Contracts, Warehouse, Safety
External Resources: Engineering Firm, Site Inspector, Construction Contractor and sub-contractors, Non-Destructive Testing contractor, Survey Contractor, Concrete Testing/Ground Testing Contractor, Community Engagement, Environmental.
Solution Impact: Replacing the valves with new valves will stop leakage issues. This ensures the MOD valves are capable of preventing the mixing of gases at different pressures, directing gas as required and isolation can be obtained when required.
Risks Reduced:
(1) Safety - leaking valves can result in safety risks for all staff and contractors. In addition leakage can result in damage to infrastructure in the event of ignition
(2) Infrastructure reliability - Leakage or can interfere with the operation of the facility if valves are required for purposes such as over pressure protection. In the event that separate MOPS can not be kept isolated, derating of

systems may be required having significant impacts pending the point in the injection/withdrawal cycle.
(3) Performance degradation. Leaking valves create re-cycle loops that reduce the effectiveness of compression.
Project Timing and Execution Risks:
Planning and Execution in Year 1. Execution Risk such as unavailability of the yard, weather, and injection/withdrawal schedule. Project impacts a crucial area of plant which can affect or be affected by numerous systems.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	222,708	$2,405,805	104

Asset Class: Storage

Business Case ID:12960

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$50,000	$2,355,805	$0	$0	$0	$0	$0	$0	$0	$0	$2,405,805
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$50,000	$2,355,805	$0	$0	$0	$0	$0	$0	$0	$0	$2,405,805
Retirement Cost											
Total Project Cost	$50,000	$2,355,805	$0	$0	$0	$0	$0	$0	$0	$0	$2,405,805

Asset Class: Storage **Business Case ID:**12960

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**12960

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**3459
Estimate Class: Class 5

Project Information

Name: SCOR:60008-Fdn Blk-Replace

Type: Enbridge Project **Start Year:** 2019

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Due to the age of the compressor infrastructure, hours operating and oil contamination, engine block foundations are deteriorating. Industry benchmarks suggest that reciprocating engine block foundations degrade in 25 years or less for engines that run 24/7 . Excessive bearing deflections place cyclic stresses on the crankshaft of the unit leading to increased frequency of bearing failure and increased potential for a crankshaft fatigue failure. Unit reliability will diminished dramatically if repairs are not performed. Worst case consequence is unit unavailability during a design day.
Compressor foundations have been considered in the Asset Health Review. Condition assessment is largely visual. The telltale sign of poor foundation condition is the existence of cracks on the surface of the foundation, with oil seeping out of the crack. Cracks typically extend to a depth that is consistent with the bottom of the unit's anchor bolts.
Without remediation, failing foundations will allow unit settlement, creating a misalignment of bearings. Frequency of bearing failures increases - reducing operation reliability. Collateral damage to the crankshaft is also common.
Asset: Compressor foundations.
Related Program:Not Applicable

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost estimate is based on historical costs for similar projects and SMA review. The project will take ~90 days (2 - 10 hr shifts) to complete with Enbridge Mechanics providing facilitation support to the OEM who will be contracted as the third party providing labour and execute the work.
Assumptions include 1) volumes of concrete removed and re-installed do not vary from previous foundations replaced 2) no new additional work to support and secure the compressor unit is required 3) foundation blocks were installed at different times and are part of different 'vintages.' Assuming vintage worked on is not more difficult to remove than foundations used for basis of estimate.
Scope:
Remove and replace the foundation that is failing on this machine, K708. The manufacturers expected life span is ~25 yrs. The foundation of this machine is not 40+ yrs old and is begin to crack due to fatigue failure.
Task Breakdown:
-Set the up the work area. Enbridge contractors to remove the piping and cables that will interfere with the work area.
-Remove the compressor cylinders and distance pieces.
-Build the dust containment shelter around the machine and install the air filtration units.
-Remove the foundation (cement and rebar block, "10'w x 8'h x 30'l)
-Prepare the existing cement matt for the new foundation
-Install the new rebar and inspect
-Build the cement forms and reinforce
-Pour the cement in one continuous pour
-Remove the cement form and remove any high points
-Install compressor distance pieces and cylinders
-Install piping and cables

-Complete PSSR with Operations
-Perform run tests and then return to Operations
Resources:
Resources:
-1 Enbridge Project Lead - Duration of the project
-1 Enbridge representative (Mechanic) days
-1 Enbridge rep (Mechanic) nights
-1 Dresser Rand Project Manager
-1 Dresser Rand Field service Rep
-~4 - 8 contract MW's for the duration of the work
-~6 Dresser Rand Mechanics for the duration of the work
-Mechanical Contractor team of 4, 2 weeks for removal, 3 weeks for reinstall
-1 electric contractor team of 3, 1 week for removal, 2 weeks for reinstall
-4 Enbridge mechanics during final assembly, 2 weeks
-Crane company for heavy lifts, ~5 days
Solution Impact: This project replaces the entire foundation of the machine. Failure of a foundation can result in a crank failure that could take the machine out of service for more than a year and be as much as 10 million dollars to complete the crankshaft replacement. The new foundation will provided an addition 25 yrs. life to the component of the machine.
Risks Reduced:
(1) Increased reliability of the associated equipment. This increased reliability provides a customer satisfaction risk reduction.
(2) Reduced risk of a long term outage due bearing failures and possible (ensuing) crankshaft failure.
Project Timing and Execution Risks:
Install Year 1
The scope will take ~90 days (2 - 10 hr shifts) to complete the work with Enbridge Mechanics providing facilitation support.
To complete the project, the contract will need to be awarded within the first 2 months of the year to ensure the required technical support, engineering, materials and labour can be secured for the project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	512,595	$2,050,000	340

Asset Class: Storage

Business Case ID:3459

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$0	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,050,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$0	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,050,000
Retirement Cost	$1,400,000										$1,400,000
Total Project Cost	$1,400,000	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,450,000

Asset Class: Storage **Business Case ID:**3459

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0	
Once in 10 to 100 years							
Once in 100 to 1000 years						R1	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0						
Once in 10 to 100 years							
Once in 100 to 1000 years	R1						
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**3459

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0						
Once in 10 to 100 years							
Once in 100 to 1000 years	R1						
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0	
Once in 10 to 100 years							
Once in 100 to 1000 years						R1	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**3460
Estimate Class: Class 5

Project Information

Name: SCOR:60007-Fdn Blk-Replace

Type: Enbridge Project **Start Year:** 2020

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Due to the age of the compressor infrastructure, operating hours and oil contamination, engine block foundations are deteriorating. Industry benchmarks suggest that reciprocating engine block foundations degrade in 25 years or less for engines that run 24/7. Excessive bearing deflections place cyclic stresses on the crankshaft of the unit leading to increased frequency of bearing failure and increased potential for a crankshaft fatigue failure. Unit reliability will diminish dramatically if repairs are not performed. The worst case consequence is unit unavailability during a design day. Compressor foundations have been considered in the Asset Health Review. Condition assessment is largely visual. A telltale sign of poor foundation condition is the existence of cracks on the surface of the foundation, with oil seeping out of the crack. Cracks typically extend to a depth that is consistent with the bottom of the unit's anchor bolts. Without remediation, failing foundations will allow unit settlement, creating a misalignment of bearings. Frequency of bearing failures increases - reducing operation reliability. Collateral damage to the crankshaft is also common.
Asset: Compressor foundations.
Related Programs/Business Cases: Not Applicable.

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost estimate is based on historical costs for similar projects and SMA review. The project will take ~90 days (2 - 10 hr shifts) to complete with Enbridge Mechanics providing facilitation support to the OEM who will be contracted as the third party providing labour and execute the work.
Assumptions:
1) Volumes of concrete removed and re-installed do not vary from previous foundations replaced
2) No new additional work to support and secure the compressor unit is required.
3) Foundation blocks were installed at different times and are part of different vintages. Assuming a storage asset's vintage is not more difficult to remove than foundations used as a basis for estimate.
Scope: Remove and replace the foundation that is failing on K707. The manufacturers expected life span is ~25 yrs. The foundation of this machine is not 40+ yrs old and is beginning to crack due to fatigue failure.
Task Breakdown: -Set the up the work area. Enbridge contractors to remove the piping and cables that will interfere with the work area. -Remove the compressor cylinders and distance pieces. -Build the dust containment shelter around the machine and install the air filtration units. -Remove the foundation (cement and rebar block, "10'w x 8'h x 30'l) -Prepare the existing cement matt for the new foundation -Install the new rebar and inspect -Build the cement forms and reinforce -Pour the cement in one continuous pour -Remove the cement form and remove any high points -Install compressor distance pieces and cylinders -Install piping and cables -Complete PSSR with Operations -Perform run tests and then return to Operations
Resources
-1 Enbridge Project Lead - Duration of the project
-1 Enbridge representative (Mechanic) days
-1 Enbridge rep (Mechanic) nights
-1 Dresser Rand Project Manager
-1 Dresser Rand Field service Rep

- ~4 - 8 contract MW's for the duration of the work
- ~6 Dresser Rand Mechanics for the duration of the work

-Mechanical Contractor team of 4, 2 weeks for removal, 3 weeks for reinstall
-1 electric contractor team of 3, 1 week for removal, 2 weeks for reinstall
-4 Enbridge mechanics during final assembly, 2 weeks
-Crane company for heavy lifts, ~5 days
Solution Impact: This project replaces the entire foundation of the machine. Failure of a foundation can result in a crank failure that could take the machine out of service for more than a year and require as much as $10M dollars to complete the crankshaft replacement. The new foundation will provided an addition 25 years to the component of the machine.
Risks Reduced:
(1) Increased reliability of the associated equipment. This increased reliability provides a customer satisfaction risk reduction.
(2) Reduced risk of a long term outage due bearing failures and possible (ensuing) crankshaft failure.
Project Timing and Execution Risks
Year 1 The scope will take ~90 days (2 - 10 hr shifts) to complete the work with Enbridge Mechanics providing facilitation support. To complete the project, the contract will need to be awarded within the first 2 months of the year to ensure the required technical support, engineering, materials and labour can be secured for the project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	348,255	$2,050,000	231

Asset Class: Storage

Estimate Class: Class 5

Business Case ID:3460

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$0	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,050,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$0	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,050,000
Retirement Cost	$1,400,000										$1,400,000
Total Project Cost	$1,400,000	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,450,000

Asset Class: Storage **Business Case ID:**3460

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0	
Once in 10 to 100 years							
Once in 100 to 1000 years						R1	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0						
Once in 10 to 100 years							
Once in 100 to 1000 years	R1						
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**3460

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0						
Once in 10 to 100 years							
Once in 100 to 1000 years	R1						
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0	
Once in 10 to 100 years							
Once in 100 to 1000 years						R1	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Project Information

Name: SCOR:60004-Fdn Blk-Replace

Type: Enbridge Project **Start Year:** 2022

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Due to the age of the compressor infrastructure, hours operating and oil contamination, engine block foundations are deteriorating. Industry benchmarks suggest that reciprocating engine block foundations degrade in 25 years or less for engines that run 24/7. Excessive bearing deflections place cyclic stresses on the crankshaft of the unit, leading to increased frequency of bearing failure and increased potential for a crankshaft fatigue failure. Unit reliability will be diminished dramatically if repairs are not performed. Worst case consequence is unit unavailability during a design day. Compressor foundations have been considered in the Asset Health Review. Condition assessment is largely visual. The telltale sign of poor foundation condition is the existence of cracks on the surface of the foundation, with oil seeping out of the crack. Cracks typically extend to a depth that is consistent with the bottom of the unit's anchor bolts. Without remediation, failing foundations will allow unit settlement, creating a misalignment of bearings. Frequency of bearing failures increases - reducing operation reliability. Collateral damage to the crankshaft is also common.
Asset: Compressor foundations.
Related Programs/BCs: Not Applicable

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost estimate is based on historical costs for similar projects and SMA review. The project will take ~90 days (2 - 10 hr shifts) to complete with Enbridge Mechanics providing facilitation support to the OEM who will be contracted as the third party providing labour and execute the work.
Assumptions:
1) Volumes of concrete removed and re-installed do not vary from previous foundations replaced
2) No new additional work to support and secure the compressor unit is required.
3) Foundation blocks were installed at different times and are part of different vintages. Assuming a storage asset's vintage is not more difficult to remove than foundations used as a basis for estimate.
Scope: Remove and replace the foundation that is failing on K704. The manufacturers' expected life span is ~25 yrs. The foundation of this machine is not 40+ yrs old and is beginning to crack due to fatigue failure.
Task Breakdown: -Set the up the work area. Enbridge contractors to remove the piping and cables that will interfere with the work area. -Remove the compressor cylinders and distance pieces. -Build the dust containment shelter around the machine and install the air filtration units. -Remove the foundation (cement and rebar block, "10'w x 8'h x 30'l) -Prepare the existing cement matt for the new foundation -Install the new rebar and inspect -Build the cement forms and reinforce -Pour the cement in one continuous pour -Remove the cement form and remove any high points -Install compressor distance pieces and cylinders -Install piping and cables -Complete PSSR with Operations -Perform run tests and then return to Operations
Resources: -1 Enbridge Project Lead - Duration of the project -1 Enbridge representative (Mechanic) days -1 Enbridge rep (Mechanic) nights -1 Dresser Rand Project Manager -1 Dresser Rand Field service Rep -~4 - 8 contract MW's for the duration of the work -~6 Dresser Rand Mechanics for the duration of the work -Mechanical Contractor team of 4, 2 weeks for removal, 3 weeks for reinstall -1 electric contractor team of 3, 1 week for removal, 2 weeks for reinstall -4 Enbridge mechanics during final assembly, 2 weeks -Crane company for heavy lifts, ~5 days
Solution Impact: This project replaces the entire foundation of the machine. Failure of a foundation can result in a

crank failure that could take the machine out of service for more than a year and be as much as $10M dollars to complete the crankshaft replacement. The new foundation will provided an addition 25 yrs. life to the component of the machine.
Risks Reduced: (1) Increased reliability of the associated equipment. This increased reliability provides a customer satisfaction risk reduction. (2) Reduced risk of a long term outage due bearing failures and possible (ensuing) crankshaft failure.
Project Timing and Execution Risks:
Year 1 The scope will take ~90 days (2 - 10 hr shifts) to complete the work with Enbridge Mechanics providing facilitation support. To complete the project, the contract will need to be awarded within the first 2 months of the year to ensure the required technical support, engineering, materials and labour can be secured for the project.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	650,565	$2,050,000	432

Asset Class: Storage

Business Case ID:5624

Estimate Class: Class 5

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,050,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,050,000
Retirement Cost	$1,400,000										$1,400,000
Total Project Cost	$3,450,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,450,000

Asset Class: Storage **Business Case ID:**5624

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0	
Once in 10 to 100 years							
Once in 100 to 1000 years						R1	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0						
Once in 10 to 100 years							
Once in 100 to 1000 years	R1						
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**5624

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years	R0						
Once in 10 to 100 years							
Once in 100 to 1000 years	R1						
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0	
Once in 10 to 100 years							
Once in 100 to 1000 years						R1	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**11703
Estimate Class: Class 5

Project Information

Name: SCOR:Storage-Maintenance

Type: Enbridge Program **Start Year:** 2017

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

The Corunna Compressor Station (SCOR) was first constructed in 1964. Units K701, K702 and K703 were installed to manage storage inventory for only four reservoirs - Corunna (PCOR), Seckerton (PSEC), Mid-Kimball Colinville (PMKC) and South-Kimball Colinville (SKC). Gas was transported to Dawn via a single NPS30 pipeline. Storage inventory grew from 1964 with the addition of 8 compressors as follows: K704 – 1968; K705 – 1970; K706 – 1972; K707 – 1973; K708 – 1974; K709 – 1980; K710 – 1983; K711 – 1995. The OEM for these compressors was exclusively Dresser-Rand. Mass production of these units by Dresser-Rand ended in the early 1980's. Dresser-Rand continues to support these assets as legacy equipment for which they supply parts and some maintenance expertise. Units require constant upgrading of subsystems, when original systems become worn-out and/or obsolete. Environmental compliance is another driver that forces periodic upgrades of subsystems. Should compressor equipment become inoperable due to obsolescence or substantial mechanical failures, peak day deliverability will be reduced, causing an increased CSAT risk for EGD customers.
Asset: All Integral Compressors at SCOR.
Related Programs/BCs: Not Applicable.

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Basis of estimate is a roll-up of cost estimates contained in individual child projects. Typically, estimates are based on SMA input/experience. Assumptions will vary by child project or project theme. This business case is a program made up of a collection of child projects - each related to ongoing maintenance capital needs for 8 existing compressors. This program assumes that K701/2/3 will be replaced during the course of the 10 year plan, such that maintenance capital will cease to be needed for these units. Child projects in this program are all expected to cost less than $250,000. Child projects themes included in this Program are as follows:
(1) Compressor overhauls due to wear
(2) Engine overhauls due to wear
(3) iFlow System upgrades to detect detonation and improve compressor performance
(4) Compressor Valve upgrades due to wear and to improve compressor performance
(5) Instrument and Electrical upgrades (Gas Detector, MCCs, Transfer switch, Flow Control Valve Positioners, Flow Meters, PLCs and Panels, Heat Tracing, Utility Valves) due to obsolescence.
(6) Piping Upgrades (Bypass Valves, Fuel Gas Recovery System) for improved operational reliability
Refer to child project business cases for more details.
Resources: Resources are generally internal because child projects are less than $250,000. Resources will include: Internal Resources: Engineering, Document Control, Reservoir group, I&E, Operations, Execution, Finance, Contracts, Warehouse, Safety
Solution Impact: Refer to child project business cases.
Project Timing and Execution Risks: Refer to child project business cases.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	3,888,549	$11,171,210	474

Asset Class: Storage **Business Case ID:**11703

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$909,755	$4,339,100	$1,240,154	$1,017,800	$1,134,800	$518,000	$366,200	$564,200	$678,201	$403,000	$11,171,210
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$909,755	$4,339,100	$1,240,154	$1,017,800	$1,134,800	$518,000	$366,200	$564,200	$678,201	$403,000	$11,171,210
Retirement Cost			$15,000								$15,000
Total Project Cost	$909,755	$4,339,100	$1,255,154	$1,017,800	$1,134,800	$518,000	$366,200	$564,200	$678,201	$403,000	$11,186,210

Asset Class: Storage **Business Case ID:** 11703

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years				R1			R0

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R0R1						

Asset Class: Storage **Business Case ID:**11703

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							R0R1

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							R0R1

Asset Class: Storage **Business Case ID:**18183
Estimate Class:

Project Information

Name: SCOR:Storage Renewal-FEED

Type: Enbridge Project **Start Year:** 2019

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

Primary concern is the sustainability of SCOR compression. Original three compressors - K701/2/3 - were installed in 1964. K701/2/3 are needed to achieve peak day deliverability (February 28th) and late season deliverability through the month of March.
Reliability of K701/2/3 is 3.5 times lower than the remaining 8 compressor units. The main issue is related to Lean Burn Conversions (LBCs) which were originally installed from 2007 to 2010. These LBCs were designed and tested on a test engine at an OEM facility, but were never proven out using in-service compressors. As a result, completion of the conversions stretched out to 2013, due to manufacturing quality, poor fuel consumption, poor NOx output and controls issues. There are only 4 of this particular LBC kits in the world and 3 are located at SCOR.

In addition to K701/2/3 reliability issues, Dresser-Rand (the OEM), supplied fuel balancing valves and an autobalancing panel (Devilbliss) for K701/2 which became obsolete after less than 5 years of service. Obsolescence of these components - which are part of the LBC kit - demonstrates that the OEM is unable to sustain the level of technical support that they claim publically.
Another example of Dresser-Rand's declining ability to support SCOR compressor units is the crankshaft failure of K705. While this failure cannot be attributed to Dresser-Rand, it did demonstrate that the cost and delivery of major replacement parts very much exceeded the recent claims by the OEM.
Declining technical support is most acute for K701/2/3 because there is a very small installed base, globally. Remaining 8 SCOR compressors are better supported because they are a successor model to the K701/2/3 compressors, with a much larger installed base.
Based on reliability assessments K701/2/3 units are at or beyond expected end of life. Spending more capital dollars on this equipment, assuming an additional 40 yr asset life, is counterintuitive.
Asset: SCOR Compressors
Related Programs: SCOR:Storage-Renewal

Compliance: N

Solution Description:

Scope of Work:
Solution/Cost Basis: FEED cost estimate is based on Class 5 work assuming replacement of three regulated compressors (K701/2/3) with a modern centrifugal compressor.
Class 5 costing assumptions include:
(i) a new compressor located on the East side of Tecumseh Road;
(ii) a new yard to interconnect a new compressor to the pool pipelines and the NPS30 transmission pipelines;
(iii) new yard layout will be designed with future retirement of existing compressor base - beyond replacement of only K701/2/3.
An alternative to replacement compression at SCOR, is being evaluated which will consider synergies with Union Gas.
Regardless of the solution selected, FEED work for new assets to replace K701/2/3 will be performed in the proposed Start Year.

Proposed work includes development of a Class 3 cost estimate, development of P&IDs, site layout drawings showing a plan view of proposed new assets, typical arrangement drawings, updated DBM needed before detailed design, permitting plan, procurement plan, initial schedule.

Resources:
Internal:
Engineering,
Doc Control,
Lands,
Reservoir Group,
Instar and Elect,
Operations,
Execution,
Finance,
Contracts,
Warehouse,
Safety.
EHS,
Procurement

External:
Eng. Firm,
Community Engagement,
Environmental

Solution Impact:
Since this BC is simply the FEED for a larger proposed project (i.e. BC 11705), the risk reductions are prorated against the entire estimated spend as follows:

Risks Reduced: (High Level)
(1) Compressor Reliability, especially for K701/2/3, is poor. K701/2/3 units are needed for low end withdrawal - February 28 to April 30 - as expected by the Gas Supply plan. Replacement of K701/2/3 will reduce CSAT risk.
(2) Aging support (i.e. auxiliary) systems are becoming obsolete. These aging support systems could increased outage durations and repair costs thereby increasing CSAT risk.
(3) Declining OEM technical expertise is expected to Increase outage durations, due to long lead time for parts, and increase repair costs. Replacement of K701/2/3 will reduce CSAT risk.
Opportunities: (High Level)
(1) Reduced maintenance costs
(2) Reduced warehousing costs for long lead items.
(3) Optimized solution has the potential to reduce regulated inventory during late season withdrawal, while still achieving or exceeding historical late season deliverability.

Project Timing and Execution Risks:
Year 1 - FEED ONLY
Purpose of a FEED only BC is to allow for development of: a Class 3 cost estimate, a site plan, obtain municipal permits and obtain drainage and Air Emissions ECAs - before the full project - BC11705 - is sanctioned.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$2,500,000	0

Asset Class: Storage **Business Case ID:**18183

Estimate Class:

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$2,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,500,000
Retirement Cost											
Total Project Cost	$2,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,500,000

Asset Class: Storage **Business Case ID:**18183

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**18183

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**19128
Estimate Class: Class 5

Project Information

Name: SCOR:61005 Crankshaft-Replace

Type: Enbridge Project **Start Year:** 2018

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

A crankshaft failure occurred on the K705 compressor unit - May 29th, 2018. During a routine bearing inspection, a crack was discovered in the crankshaft at the crank throw bearing surface for power cylinder #7. Subsequent inspection and testing between May 29th, 2018 and July 13th, confirmed that the crankshaft was not repairable and needed to be condemned - retired from service. Crankshaft failures are very rare, and in this case was thought to be caused by a detonation event which occurred July 21st, 2017. Further metallurgical testing is planned to confirm that the crack in the damaged crankshaft are consistent with a high stress/low frequency loads caused by detonation.
The K705 asset is needed to achieve the Gas Supply plan during peak day withdrawal nominations and needed to provide first stage compression during late season injections. The long term outage of K705 will increase the Gas Supply risk to regulated customers.
Assets: Compressor K705
Related Program (if applicable)*: Not Applicable

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Procure and install a single, newly manufactured crankshaft from Dresser-Rand. Much of the compressor disassembly and re-assembly will be performed by in-house maintenance resources, with additional contract resources employed where needed. Cost estimate assumes that the existing building crane, rated at 10 tonnes, can be temporarily outfitted with additional engineered supports, allowing it to lift beyond the current rating. Increased crank rating is needed to lift the upper deck of the engine frame out of the way.
Scope:
-Complete PO for new Crankshaft - 36 weeks delivery
-Set the up the work area. Enbridge contractors to remove the piping and cables that will interfere with the work area.
-Remove cams and the power cylinders heads, liners, pistons and connecting rods.
-Remove power cylinder jugs
-Installed engineered support system for the building crane.
-Remove upper deck
-Remove main bearing caps and crankshaft
-Prepare new crankshaft with "final fit" machining as needed
-Install crankshaft complete with recommended counter balance weights
-Install main bearing caps
-Check crankshaft alignment. Alignbore if needed.
-Reinstall upper deck, jugs, connecting rods, pistons, heads and cams
-Remove temporary crank supports
-Complete PSSR with Operations
-Perform run tests and then return to Operations

Resources:

Internal:
-1 Enbridge Project Lead - Duration of the project
-1 Enbridge representative (Mechanic) days
-1 Enbridge rep (Mechanic) nights
External:
-1 Dresser Rand Project Manager
-1 Dresser Rand Field service Rep
-~4 - 8 contract MW's for the duration of the work
-~6 Dresser Rand Mechanics for the duration of the work -Mechanical Contractor team of 4, 2 weeks for removal, 3 weeks for reinstall
-1 electric contractor team of 3, 1 week for removal, 2 weeks for reinstall
-4 Enbridge mechanics during final assembly, 2 weeks
-Crane company for heavy lifts, ~5 days

Solution Impact:
This project replaces the existing K705 crankshaft with new (i.e. returned to zero op-hours). Gas Supply risk will be mitigated and the operational reliability risk of K705 will be reduced.

Project Timing and Execution Risks:
Year 1: Initiate a PO for the new crankshaft and perform a lift study on the building crane.
Year 2: The scope will take ~90 days to complete, with Enbridge Mechanics providing facilitation support.
To complete the project, the PO for a new crankshaft will need to be awarded in July 2018. Delivery is quoted as 36 weeks. Delivery of the crankshaft is the largest project execution risk - delivery delays are a threat to 2019 injection schedule and 2020 peak day withdrawals.
In addition, a new crankshaft may not sit the same way in the existing main bearings. There is a risk that the new crankshaft will require an alignbore before re-assembly. Alignbore is estimated to cost an additional $1.289M, and is not in the original cost estimate for this project

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,209,489	$3,160,421	521

Asset Class: Storage **Business Case ID:**19128

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$34,800	$3,125,621	$0	$0	$0	$0	$0	$0	$0	$0	$3,160,421
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$34,800	$3,125,621	$0	$0	$0	$0	$0	$0	$0	$0	$3,160,421
Retirement Cost	$23,200	$867,485									$890,685
Total Project Cost	$58,000	$3,993,106	$0	$0	$0	$0	$0	$0	$0	$0	$4,051,106

Asset Class: Storage **Business Case ID:**19128

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years						R1	
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years	R1						
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**19128

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years	R1						
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years						R1	
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage | **Business Case ID:**1811
Estimate Class: Class 5

Project Information

Name: SCOR:Meter Area-Upgrade

Type: Enbridge Project | **Start Year:** 2018

Asset Program: Compressor Equipment

Project Type: Compressor Equipment

Issue/Concern:

There are two drivers for replacement of the existing meter area:
The existing cross flow header can be subjected to very high pipe velocities creating flow induced vibration
The meter area is no longer used to meter pool inventory and can be made safer by replacing with modern buried pipe designs.
The existing cross flow header allows interconnection of the DOW header (Maximum Operating Pressure (MOP) of 1550 psig) with all remaining headers (MOPs of 1200 psig and 900 psig). This interconnection is necessary during low-end withdrawal from DOW. Low-end withdrawal from DOW requires that the DOW header be allowed to flow into SCOR on first stage compression (MOP of 1200 psig). Due to the MOP differences between DOW and the remaining headers, the DOW header is unable to connect directly to lower pressure compressors on the suction side. The cross flow header was added when the DOW reservoir was developed. The existing cross flow header interconnects DOW to the lower pressure headers by way of manual ball valves. The DOW pool pipeline and headers system is sized at NPS24. Sizing of the cross flow header is such that DOW flows into 1200 psig headers through valves as small as NPS12. This discrepancy creates a pinch point with excessively high velocities (>200 ft/s), causing flow-induced vibration that can be felt in the ground. In addition to the sizing issue, CSA Z662 code requires that automatic overpressure protection be provided whenever pipe of dissimilar MOPs are connected. Suitable Over-pressure Protection (OPP) does not exist on the current cross flow header. Risk can be dramatically reduced by replacing the existing cross flow header with one that is appropriately sized and with over-pressure protection. Finally, the existing meter area is no longer used for inventory management - it is simply the flow path used to convey gas back and forth from reservoirs. Limited cross flow functionality is provided in the current meter area piping. The pipe is of unknown material composition, with unknown strength characteristics, and is comprised of many flange connections in an area frequently accessed by personnel. Piping is also above grade. Tolerance of damage risks related to above- grade piping is no longer warranted, and can be reduced by replacing with buried pipe.
Asset: SCOR Header system and Meter Area
Related Programs/BCs: Resolution of this concern stands alone, but SCOR compressor replacement (replacement of K701/2/3) relies on resolution of this concern.

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Install three Nominal Pipe Size (NPS) 30 buried cross flow headers, and replacement of 15 NPS12 above-grade meter runs with seven buried pipes ranging from NPS16 to NPS24. New piping will be designed with pressure control and protection provisions needed to safely manage multiple pipeline and header MOPs ranging from 900 psig to 1550 psig. Work includes full gating cycle due to scale and complexity including: stakeholder consultations, planning, detailed design, permit applications, procurement, retaining a construction contractor, isolate system, install temporary drainage system, demolition of structures/equipment to be replaced, erect buildings if required, install air system modifications if required, prefab piping, hydrotesting, demolish meter runs, install new piping and auxilliary systems, NDE as required, coating, inspection, train staff, energize system, remediating site, and records updates.
Resources:
Internal: Engineering, Document Control, Lands, Reservoir Group, Instrumentation & Electrical, Operations,

Execution, Finance, Contracts, Warehouse, Safety. EHS, Procurement
External: Engineering Firm, Site Inspector, Construction contractor and sub-contractors, Non-Destructive Testing contractor, Survey contractor, Concrete Testing/Ground Testing contractor, Community Engagement, Environmental.
Solution Impact: Risks Reduced:
(1) Replacement pipe will be welded in place. Replacement pipe will be a single run per header as compared to the current multiple runs. Fittings such as flanges, bolt in meters and bolt on valves will be eliminated. All these factors work to reduce the number of potential leak paths
(2) Piping would be buried reducing risk of vehicle impact.
(3) Many valves in the existing meter run area are original installations and reaching the end of their lifecycle with increased risk of internal bypass. Replacement valves will be able to fully seal as required.
(4) Diameter changes at existing cross flow header will be eliminated, preventing piping from exceeding unsafe gas velocity.
(5) All new equipment would be purchased and installed to modern specifications designed specifically for high pressures the facility can tolerate. Replacement pipe will be designed to modern standards (CE, CVN testing, DWTT etc).
(6) Replacement includes Pressure Control (PC) and OPP designed to address range of MOPs in EGS systems. Modifications that result in operational bottlenecks installed over the history of EGS will be incorporated into a permanent, functional installation.
Project Timing and Execution Risks:
Year 1-Design work, Permits, Approvals
Year 2-Procure, Permits
Year 3-Construction
Challenges:
1.Project is occurring in an area where modifications have been made for more than 50 years. Recordkeeping has gone through varying levels of detail during this time. Transfer between record systems creates a risk of unidentified pipe being discovered during execution. Should this occur during execution, short delays may be experienced.
2.The work area has a significant amount of sand backfill. Combined with the water table, excavation will require shoring and drainage systems.
3.This project replaces a vital section of plant piping execution delays will impact injection/withdrawal schedules
4.Material delays will impact execution of the project. Long lead items should be ordered in advance.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	7,382,403	$45,000,000	310

Asset Class: Storage **Business Case ID:**1811

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$1,400,000	$11,000,000	$18,000,000	$14,600,000	$0	$0	$0	$0	$0	$0	$45,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,400,000	$11,000,000	$18,000,000	$14,600,000	$0	$0	$0	$0	$0	$0	$45,000,000
Retirement Cost											
Total Project Cost	$1,400,000	$11,000,000	$18,000,000	$14,600,000	$0	$0	$0	$0	$0	$0	$45,000,000

Asset Class: Storage **Business Case ID:**1811

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0R1	
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years					R1	R0	
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Risk Assessment currently under development.

Asset Class: Storage **Business Case ID:**1811

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0R1	
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0R1	
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Risk Assessment currently under development.

Asset Class: Storage **Business Case ID:**6376
Estimate Class: Class 5

Project Information

Name: LCRW:Wells-Upgrade

Type: Enbridge Project **Start Year:** 2025

Asset Program: Field Lines

Project Type: Field Lines

Issue/Concern:

Wells at Crowland are much older than other wells in EGS. Due to age, the wells were constructed to a production standard which would normally be retired after 10 years. Instead, the wells were converted to Storage service in the early 1970's and continue to operate ever since. Many wells have been relined, increasing the risk of leaks. Most wells possess only two casings - the current standard requires a minimum of three. The two-casing design at Crowland is comprised of an inner casing that runs from the surface to the reservoir (about 225m) plus a surface casing that runs from the surface to a depth of about 20m. Most wells do not have an intermediate casing with cement between the inner and intermediate casings, however, there is cement between the inner casing and the surrounding rock. This provides a poor barrier to gas flow should the inner casing fail. In addition, none of the wells at Crowland employ wellheads and master valves. Instead, the inner casing is simply connected to a flanged 1/4 turn valve without wing valves or wellhead vents. The surface casing is separated from the surface using cement. There are no casing vents and part of the inner casing (typically a length of 2 to 16 inches) is exposed at the surface. The lack of casing vents eliminates normal approaches to controlling a failed well. Vertilogs have been performed in the last 5 years, and indicated that the inner casing integrity is adequate, although two of 26 wells needed to be abandoned. Currently, there are 24 wells remaining. Bond logs have not been performed yet to determine the condition of cement at sulphur layers. Primary concerns are:
(1) Code compliance of the wells and wellheads. Technically, these wells were constructed before CSA Z341 came into force, and are grandfathered. However, a well failure would likely be viewed negatively by technical regulators.
(2) Risk to employees and the public - in the event of a loss of containment, there are insufficient barriers to gas flow. Public risk also extends to possible sulphur contamination of well water at surface levels. In addition to the wells, much of the gathering system is as old as the wells. The gathering system is operating at <30% SMYS, which means that they have not be considered for integrity inspections until recently and that the gathering system pipe condition is unknown after 50 to 100 years of operation.
Asset: Crowland wells and gathering system.
Related Programs/BCs: PCRW:Wells-Upgrade.
This risk is under consideration in conjunction with an overall Crowland upgrade program - MCRW:Storage-Renewal. Issues related to the wells and gathering system should be considered together with other additional compressor station issues/concerns.

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost estimate allows for:
(i) Design of 2 new Hwell laterals
(ii) Design of well lateral/loop modifications for eight existing Injection/Wthdrawal Vwells
(iii) Purchase of materialsl
(iv) Install 10 new laterals and abandon eight existing ones. The majority of design and installation work will be performed by third parties.
Assumptions:
1) The Crowland reservoir is located in a marshy area creating a number of construction and environmental challenges. The estimate is expected to account for these challenges but cost updates may be required following design work.

2) Work is coordinated with the Reservoir Group because there is a dependency on business case PCRW:Wells-Upgrade. Requirements to support this project include, but not limited to: design, survey, material procurement, pressure test, coating, excavation, field installation, welding, backfill, compaction testing, construction supervision, quality control, quality package, redlines, as built, and commissioning.
Resources: Internal Resources: Engineering, Document Control, Lands Coordinator, Reservoir group, I&E, Operations, Execution, Finance, Contracts, Warehouse, Safety.
External Resources: Engineering Firm, Site Inspector (weld\coat), Construction Contractor and sub-contractors, Non-Destructive Testing contractor, Survey contractor, Concrete\Ground Testing contractor Community Engagement, Environmental.
Solution Impact: This business case is linked to the PCRW:Wells-Upgrade business case, where CRW well upgrades are needed to modernize wellheads and master valves, and to abandon eight wells in favour of two new Hwells. This business case provides the piping connection between the new/upgraded wells to the gathering system. This business cases allows risk reductions identified in BC PCRW:Wells-Upgrade to be realized. Risks Reduced:
(1) Loss of containment from exposed inner casing above the surface level of the well.
(2) Effects of well casing corrosion, where exposed to corrosive sulphur, can be mitigated more readily with modern wellheads and master valves, which limits pressurized gas leaking through the well casing and contaminating well water at surface with sulphur.
(3) Effects of deteriorated cement, between the casing and rock, can be mitigated more readily with modern wellheads and master valves. Existing cement is not resistant to the effects of sulphur and has reduced life expectancy. Compromised cement may allow well casing leaks to migrate to surface.
Project Timing and Execution Risks:
Year 1: Pre-design of new lateral connections.
Year 2: Installation of new well laterals after wells have been completed. Timing of work is highly unconstrained. Provided that work is not completed between December and March, there is a great deal of timing flexibility. Well drilling work is anticipated to occur from Q2 to Q3 in Year 2, therefore lateral construction will likely occur from Q3 to Q4 Year 2.
Execution Risks:
1) Reservoir and associated laterals are in a swampy area. SAR must be considered and could impact the time of year execution is allowed.
2) Co-ordination of well work and lateral construction could force lateral construction into Q2 of Year 3.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	289,621	$3,456,764	124

Asset Class: Storage

Estimate Class: Class 5

Business Case ID:6376

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$173,185	$3,283,579	$0	$0	$0	$0	$0	$0	$0	$0	$3,456,764
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$173,185	$3,283,579	$0	$0	$0	$0	$0	$0	$0	$0	$3,456,764
Retirement Cost											
Total Project Cost	$173,185	$3,283,579	$0	$0	$0	$0	$0	$0	$0	$0	$3,456,764

Asset Class: Storage **Business Case ID:**6376

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0R1			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**6376

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0R1			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**6363
Estimate Class: Class 5

Project Information

Name: PSKC:TKC67H New HWell

Type: Enbridge Project **Start Year:** 2018

Asset Program: Wells and Well Equipment

Project Type: Wells & Well Equipment

Issue/Concern:

Micro-annulus leaks have been occurring on wells that have been re-lined. Re-lining a well may be performed when the integrity of an existing casing is inadequate, and a smaller diameter casing is installed inside the original casing (concentrically). A recent rash of these relined wells has experienced leakage between the two casings.
Concerns:

1. Localized leakage can be prevented by sealing the flow path at the wellhead (casing vent). This action causes pressure in the space between the two casings to achieve full reservoir pressure.
2. If the annulus space is allowed to be pressurized, there is the potential for a breach of the original casing – the original casings are known to have inadequate integrity.
3. A breach of the original casing could occur anywhere along the well string – 2000 ft long/deep. Leaking, unodourized gas could come to surface at unpredictable locations.

This Issue/Concern is related to wells that are already leaking. For actively leaking wells, the following compliance requirements apply: Compliance with:
CSA Z341.1-14 - 5.3.1(a) the design of a well casing program shall provide control of pressures and fluids encountered by the well.
CSA Z341.1-14 - 5.3.6(c) Well casings shall be set and cemented at sufficient depth to ensure isolation of storage zones.
OGSRA (O/Reg 245.97) - 17 (1) An operator of a well...shall provide casing and blowout prevention equipment and maintain it in such a condition that any oil, gas or water encountered can be effectively controlled.
OGSRA (O/Reg 245.97) - 17 (3) The operator shall ensure that the well does not flow uncontrolled
O.Reg 22/00, s. 6 (2). Well abandonments resulting from the Leaking and Relined well replacement programs will diminish the flow capacity of the associated Reservoir. This performance degradation negatively impacts peak day deliverability.
The following reservoir performance deterioration due to abandonment of leaking wells has been observed:
PDOW - deliverability reduced by 60%
PMKC - deliverability reduced by 10%
PSKC - deliverability reduced by 30%
Together the associated reservoirs provide 60% of Gas Storage Working volume. Deliverability reduction of this magnitude increases CSAT risk dramatically.
Asset: South Kimball reservoir (Wells & Well Equipment asset program) and gathering system (Field Lines asset program). *
Related Programs/BCs: Installation of wells is performed by the Reservoir Group (Wells and Well Equipment asset program), installation of laterals is performed by the Project Execution group (Field Lines asset program). This separation is based on skill set and qualifications. There is a programmatic time dependence between the two asset programs.

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Estimate allows for preliminary applications and location studies, design work, purchase of materials and installation of one new horizontal well. The majority of design and installation work

will be performed by third parties.
Assumptions:
1) The project is influenced by multiple factors including but not limited to reservoir pressures, regulatory approvals, and environmental factors. Delays or changes in these factors could impact project schedule.
2) Environmental findings may impact execution costs if additional protection measures are required. Prep Work: a. Perform assessment of species at risk, archeological assessments, and stakeholder consultations. b. Submit permitting applications to regulatory bodies.
Execution Workscope: Steps involved: (i) build a well pad; (ii) purchase materials; (iii) mobilize drilling equipment; (iv) drill new Hwell; (v) demobilizing drilling equipment; (vi) install wellhead; (vii) pressure test; (viii) remediate/restore affected area. This project is has a dependency on construction of laterals to connect the well to the gathering system. Cost of this project does not reflect the cost of well lateral installation.
Resources
1. Gas Storage Reservoir Department - Project Management, Obtain permits - MNRF & OEB, Project Execution
2. EGD Regulatory - Obtain permits
3. EGD EHS Department - For OEB application: Environmental Assessment, Species at Risk & Archeological Study; Final Environmental Reports
4. EGS Procurement Group - Contracts & Purchasing - casing, wellheads, valves
5. EGD - Aboriginal Affairs – Consultation
6. Third Party Contractors:

- Wellsite Supervision
- Drilling Contractor
- Directional Drilling Contractor
- Civil Contractor - build pad & cleanup
- Mechanical Contractor
- Logging Contractors

Solution Impact: This Hwell will take the place of several (typically 3.5) Vwells which have been abandoned due to micro-annulus concerns. Currently, PSKC deliverability has reduced to an estimated 70% of the reservoir flow capacity prior to abandonment of 5 wells in 2017 and 2018.

Risks Reduced: System performance will be improved to avoid diminished reservoir flow capacity which would, in turn, reduce peak day deliverability. Replacing Vwells with Hwells yields a substantially reduced capital cost plus reduced O&M costs per Vwell as follows: 1. Property Taxes 2. Leases 3. Laneway Maintenance 4. Logging 5. Pipeline Integrity for Laterals (both O&M and Capital costs every 7 years) 6. Investigative digs for laterals. 7. Monthly Well Inspections. Replacement of 3.5 Vwells with a single Hwell is expected to yield net annual cost reduction $30k per year.
Project Timing and Execution Risks:
Year 1: - purchase long lead items - master valve, wellheads and casing - begin application process - EA, SAR, Archaeological Assessment, Consultation and apply to MNRF/OEB - build pad - contract for 3rd party services
Year 2: - obtain drilling permit - drill well in 'window' provided by EGS Operations - must coordinate with Operations to ensure that the pressure is <400psi - drill well - cleanup pad and restore site - install Instrumentation - handover well to Operations.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	132,350	$2,995,000	68

Asset Class: Storage **Business Case ID:**6363

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$300,000	$300,000	$2,395,000	$0	$0	$0	$0	$0	$0	$0	$2,995,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$300,000	$300,000	$2,395,000	$0	$0	$0	$0	$0	$0	$0	$2,995,000
Retirement Cost											
Total Project Cost	$300,000	$300,000	$2,395,000	$0	$0	$0	$0	$0	$0	$0	$2,995,000

Asset Class: Storage **Business Case ID:**6363

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Storage **Business Case ID:**6363

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Storage **Business Case ID:**13047
Estimate Class: Class 5

Project Information

Name: PSEC:TS23H Well-Install

Type: Enbridge Project **Start Year:** 2023

Asset Program: Wells and Well Equipment

Project Type: Wells & Well Equipment

Issue/Concern: Well abandonments resulting from abandoned wells since 2007 have already diminished the flow capacity of Seckerton. The proposed relined well replacement program will diminish the flow capacity of the Seckerton Reservoir even further. In addition, wells on the northern saddle of Seckerton (referred to as Seckerton North) are being shut-in during low end withdrawal in order to mitigate crude oil carry-over. The North and South saddles have limited interconnected permeability, meaning that gas migrates very slowly between the two saddles. Shutting in wells has the effect of stranding an estimated 1.5 BCF for three weeks at the end of the withdrawal cycle. This performance problem negatively impacts peak day deliverability.
Asset: Seckerton reservoir (Wells and Well Equipment asset program) and gathering system (Field Lines asset program).
Related Programs/BCs: Installation of wells is performed by the Reservoir group (Wells & Well Equipment asset program), installation of laterals is performed by the Project Execution group (Field Lines asset program). This separation is based on skill set and qualifications. There is a programmatic time dependence between the two asset programs.

Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Estimate allows for preliminary applications and studies, design work, purchase of materials and installation of one new horizontal well. The majority of design and installation work will be performed by third parties.
Assumptions:
1) The project is influenced by multiple factors including but not limited to reservoir pressures, regulatory approvals, and environmental factors. Delays or changes in these factors could impact project schedule.
2) Environmental findings may impact execution costs if additional protection measures are required. Prep Work: a. Perform assessment of species at risk, archeological assessments, and stakeholder consultations. b. Submit permitting applications to regulatory bodies.
Execution Workscope: Steps involved: (i) build a well pad; (ii) purchase materials; (iii) mobilize drilling equipment; (iv) drill new Hwell; (v) demobilizing drilling equipment; (vi) install wellhead; (vii) pressure test; (viii) remediate/restore affected area. This project is has a dependency on construction of laterals to connect the well to the gathering system. Cost of this project does not reflect the cost of well lateral installation.
Resources:
1. Gas Storage Reservoir Department - Project Management, Obtain permits - MNRF & OEB, Project Execution
2. EGD Regulatory - Obtain permits
3. EGD EHS Department - For OEB application: Environmental Assessment, Species at Risk & Archeological Study; Final Environmental Reports
4. EGS Procurement Group - Contracts & Purchasing - casing, wellheads, valves
5. EGD - Aboriginal Affairs - Consultation
6. Third Party Contractors:

- Wellsite Supervision
- Drilling Contractor

- Directional Drilling Contractor
- Civil Contractor - build pad & cleanup
- Mechanical Contractor
- Logging Contractors

Solution Impact: Currently, PSEC deliverability has already reduced since NGEIR due to abandonment of four wells with microannulus leaks and poor integrity. In addition, this solution will match the flow capacity of North Seckerton with that of South Seckerton and avoid stranding as much as 1.5 BCF during late season withdrawal. Risks Reduced: System performance will be improved to avoid diminished reservoir flow capacity that has already occurred since NGEIR. Diminished flow capacity results in reduce peak day deliverability. Replacing Vwells with Hwells yields a substantially reduced capital cost plus reduced O&M costs per Vwell as follows: 1. Property Taxes 2. Leases 3. Laneway Maintenance 4. Logging 5. Pipeline Integrity for Laterals (both O&M and Capital costs every 7 years) 6. Investigative digs for laterals. 7. Monthly Well Inspections. Replacement of 3.5 Vwells with a single Hwell is expected to yield net annual cost reduction $30k per year.
Project Timing and Execution Risks:
Year 1: - purchase long lead items - master valve, wellheads and casing - begin application process - EA, SAR, Archaeological Assessment, Consultation and apply to MNRF/OEB - build pad - contract for third party services Year 2: - obtain drilling permit - drill well in 'window' provided by EGS Operations - must coordinate with Operations to ensure that the pressure is <400psi - drill well - cleanup pad and restore site - install Instrumentation - handover well to Operations.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	124,050	$3,000,000	63

Asset Class: Storage

Business Case ID:13047

Estimate Class: Class 5

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$605,000	$2,395,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$605,000	$2,395,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,000,000
Retirement Cost											
Total Project Cost	$605,000	$2,395,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,000,000

Asset Class: Storage **Business Case ID:**13047

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years						R0	
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years	R0						
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Storage **Business Case ID:**13047

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years	R0						
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years						R0	
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Storage **Business Case ID:**6377
Estimate Class: Class 5

Project Information

Name: PCRW:Wells-Upgrade

Type: Enbridge Project **Start Year:** 2024

Asset Program: Wells and Well Equipment

Project Type: Wells & Well Equipment

Issue/Concern: Wells at Crowland are much older than other wells in EGS. Due to age, the wells were constructed to a production standard which would normally be retired after 10 years. Instead, the wells were converted to Storage service in the early 1970's and continue to operate ever since. Many wells have been relined, increasing the risk of leaks. Most wells possess only two casings - the current standard requires a minimum of three casings. The two-casing design at Crowland is comprised of an inner casing that runs from the surface to the reservoir (about 225m) plus a surface casing that runs from the surface to a depth of about 20m. Most wells do not have an intermediate casing with cement between the inner and intermediate casings, however, there is cement between the inner casing and the surrounding rock. This provides a poor barrier to gas flow should the inner casing fail. In addition, none of the wells at Crowland employ wellheads and master valves. Instead, the inner casing is simply connected to a flanged 1/4 turn valve without wing valves or wellhead vents. The surface casing is separated from the surface using cement. There are no casing vents and part of the inner casing (typically a length of 2 to 16 inches) is exposed at the surface. The lack of casing vents eliminates normal approaches to controlling a failed well. Vertilogs have been performed in the last 5 years, and indicated that the inner casing integrity is adequate, although two of 26 wells needed to be abandoned. Currently, there are 24 wells remaining. Bond logs have not been performed yet to determine the condition of cement at sulphur layers. Primary concerns are:

(1) Code compliance of the wells and wellheads. Technically, these wells were constructed before CSA Z341 came into force, and are grandfathered. However, a well failure would likely be viewed negatively by technical regulators.
(2) Risk to employees and the public - in the event of a loss of containment, there are insufficient barriers to gas flow. Public risk also extends to possible sulphur contamination of well water at surface levels. In addition to the wells, much of the gathering system is as old as the wells. The gathering system is operating at <30% SMYS, which means that they have not be considered for integrity inspections until recently and that the gathering system pipe condition is unknown after 50 to 100 years of operation.
Asset: Crowland wells and gathering system.
Related Programs/BCs: This risk is under consideration in conjunction with an overall Crowland upgrade program - MCRW:Storage-Renewal. Issues related to the wells and gathering system should be considered together with the additional compressor station issues/concerns

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Compliance: N

Solution Description:

Scope of Work: Solution/Cost Basis: Cost estimate allows for:
(i) Two drilling applications and well locations studies
(ii) Design
(iii) Materials
(iv) Core sampling
(v) Drill two new Hwells and well heads/master valves to 16 existing Vwells. The majority of design and installation work will be performed by third parties.
Assumptions:
1) Project schedule is influenced by reservoir pressures, regulatory approvals, environmental factors.
2) Environmental findings may impact execution costs.
3) Crowland is located in a marshy area which may impact execution and, subsequently, costs.

Work Sequence is as follows:
(1) Drill a vertical well to core through the confining geological formations and the storage zone. The core will be tested and an Integrity study will be completed to determine if stimulation operations can be performed in the sandstone storage zone. If the integrity tests are positive, they will be used as the basis drilling permit applications for 2 Hwells.
(2) Obtain permits to drill 2 new Hwells.
(3) Obtain approval from MNRF to remediate remaining 16 Vwells (8 Inj/Wdl; 8 obs).
(4) Install well pads.
(5) Mobilize drilling equipment.
(6) Drill Hwells.
(7) Stimulate Hwells
(8) Replace Vwell well heads.
(9) Demobilize.
(10) Remediate/restore.
Resources:
1. Gas Storage Reservoir Department - Project Management, Obtain permits - MNRF & OEB, Project Execution
2. EGD Regulatory - Obtain permits
3. EGD EHS Department - For OEB application: Environmental Assessment, Species at Risk & Archeological Study; Final Environmental Reports
4. EGS Procurement Group - Contracts & Purchasing - casing, wellheads, valves
5. EGD - Aboriginal Affairs - Consultation
6. Third Party Contractors: - Wellsite Supervision - Drilling Contractor - Directional Drilling Contractor - Core Testing Laboratories - Well Stimulation Company - Civil Contractor - build pad & cleanup - Mechanical Contractor - Logging Contractors
Solution Impact: Results of the core integrity testing will:
(i) Verify that the confining geological formations are suitable for storage
(ii) Provide inputs needed to simulate the Hwells. Up to 8 existing Vwells will be abandoned - reducing risk.
Risks Reduced:
(1) Loss of containment from exposed inner casing above the surface level of the well.
(2) Effects of well casing corrosion, where exposed to corrosive sulphur, can be mitigated more readily with modern well heads and master valves. It limits pressurized gas, leaking through the well casing, and contaminating well water at surface with sulphur.
(3) Effects of deteriorated cement, between the casing and rock, can be mitigated more readily with modern wellheads and master valves. Existing cement is not resistant to the effects of sulphur and has reduced life expectancy. Compromised cement may allow well casing leaks to migrate to surface.
Project Timing and Execution Risks:
Year 1: Prep for Vwell permits - ER, SAR, Archeay. Apply to MNRF/OEB. Order long lead items - wellheads, master valves, casing. Drilling contracts.
Year 2: Drill and core well. Test core and report. Plan well stimulations Prep for Hwells permits - ER, SAR, Archeay. Apply to MNRF/OEB. Order long lead items - wellheads, master valves, ESVs, casing. Drilling contracts.
Year 3: Drill wells, install pipelines, test wells, put wells in service.
Year 4: Abandon existing wells.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	975,917	$11,648,011	124

Asset Class: Storage **Business Case ID:**6377
Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$443,352	$1,290,371	$9,914,288	$0	$0	$0	$0	$0	$0	$0	$11,648,011
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$443,352	$1,290,371	$9,914,288	$0	$0	$0	$0	$0	$0	$0	$11,648,011
Retirement Cost			$443,352	$443,352							$886,704
Total Project Cost	$443,352	$1,290,371	$10,357,640	$443,352	$0	$0	$0	$0	$0	$0	$12,534,715

Asset Class: Storage **Business Case ID:**6377

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**6377

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Appendix 7.2-5 – Customer Assets Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Customer Assets **Business Case ID:**19983
Estimate Class: Class 3

Project Information

Name: Meter Purchases

Type: Enbridge Project **Start Year:** 2018

Asset Program: Meters - Capital Purchase Program

Project Type: Meter Purchases

Issue/Concern:

Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an “Authorized Service Provider” and adhere to Measurement Canada’s accreditation standard S-A-01.

Meters may also require exchange for issues such as: damages, leaks, customer billing issues.

Lastly, new meters are required for customer expansion projects.

Compliance: Y

Solution Description:

Scope of Work is for 2019 - 2027, and includes:
Purchase of meters for:
1) MXGI/MXGS - meters due for sampling and exchange. (61,895 units planned annually)
2) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated annually)
3) New customer additions - customer expansion projects. Units estimated as follows:
2019 - 31,288
2020 - 32,426
2021 - 32,920
2022 - 33,154
2024 - 30,347
2025 - 29,550
2026 - 28,278
2027 - 27,551
Solution Impact:
1)Compliance with governance mandated meter exchange program
2)Exchange of problematic meters
3)Support of customer expansion projects.
Resources:
System Measurement and Purchasing manages the procurement of meters.
Project Timing & Execution Risks:
This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	22,821,956	$228,717,660	135

Asset Class: Customer Assets

Business Case ID:19983

Estimate Class: Class 3

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$2,580,000	$20,621,317	$22,827,885	$21,353,189	$23,592,268	$24,687,621	$32,407,899	$24,948,153	$24,244,987	$31,454,341	$228,717,660
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,580,000	$20,621,317	$22,827,885	$21,353,189	$23,592,268	$24,687,621	$32,407,899	$24,948,153	$24,244,987	$31,454,341	$228,717,660
Retirement Cost											
Total Project Cost	$2,580,000	$20,621,317	$22,827,885	$21,353,189	$23,592,268	$24,687,621	$32,407,899	$24,948,153	$24,244,987	$31,454,341	$228,717,660

Asset Class: Customer Assets **Business Case ID:**19983

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1						R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**19983

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1						R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**16183
Estimate Class: Class 3

Project Information

Name: 2028 Meter Purchases

Type: Enbridge Project **Start Year:** 2028

Asset Program: Meters - Capital Purchase Program

Project Type: Meter Purchases

Issue/Concern:

Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Lastly, new meters are required for customer expansion projects.
Asset:
Related Program:

Compliance: Y

Solution Description:

Scope of Work includes:
Purchase of meters for:
1)MXGI - meters due for sampling and exchange. 61,895 Units Planned
2)MXOT - meter exchanges due to damage/leak/failure/customer dispute. 16,561 Units Estimated
3)New customer adds - customer expansion projects. 27,027 Units Estimated
Solution Impact:
1)Compliance with governance mandated meter exchange program
2)Exchange of problematic meters
3)Support of customer expansion projects.
Resources:
System Measurement and Purchasing manages the procurement of meters.
Project Timing & Execution Risks:
This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,449,465	$24,432,190	135

Asset Class: Customer Assets

Business Case ID:16183

Estimate Class: Class 3

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$24,432,190	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,432,190
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$24,432,190	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,432,190
Retirement Cost											
Total Project Cost	$24,432,190	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,432,190

Asset Class: Customer Assets **Business Case ID:**16183

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1					R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**16183

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1					R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**2986

Estimate Class: Class 3

Project Information

Name: 2019 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2019

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.

Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premises, resulting in failure of gas equipment, loss of containment, and potentially, a fire or explosion.

Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.

Related Program: Meter Purchases

Compliance: Y

Solution Description

Scope of Work

1) MXGI - meters due for sampling and exchange. (61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition (7,500 units estimated)
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues (10,000 units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition(17,261 units estimated)

Resources: Lakeside Gas will perform the majority of this work.

Solution Impact:

1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure

Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,293,467	$17,290,020	162

Asset Class: Customer Assets

Business Case ID:2986

Estimate Class: Class 3

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$17,290,020	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,290,020
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$17,290,020	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,290,020
Retirement Cost	$6,583,889										$6,583,889
Total Project Cost	$23,873,909	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,873,909

Asset Class: Customer Assets **Business Case ID:**2986

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**2986

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**2987
Estimate Class: Class 3

Project Information

Name: 2020 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2020

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.
Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.
Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.
Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:
1) MXGI - meters due for sampling and exchange(61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition (7,500 units estimated)
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues(10,000 units estimated)6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition (17,261 units estimated)

Resources: Lakeside Gas will perform the majority of this work.
Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure
Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,347,371	$17,696,396	162

Asset Class: Customer Assets **Business Case ID:**2987

Estimate Class: Class 3

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$17,696,396	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,696,396
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$17,696,396	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,696,396
Retirement Cost	$6,808,777										$6,808,777
Total Project Cost	$24,505,173	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,505,173

Asset Class: Customer Assets **Business Case ID:**2987

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**2987

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**2988

Estimate Class: Class 3

Project Information

Name: 2021 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2021

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.

Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.

Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.

Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:

1) MXGI - meters due for sampling and exchange. (61,895 units p)lanned
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. 16,561 (units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition. (7,500 units estimated)
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues. (10,000 units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition. (17,261 units estimated)

Resources: Lakeside Gas will perform the majority of this work.

Solution Impact:

1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure

Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,372,356	$17,884,761	162

Asset Class: Customer Assets

Business Case ID:2988

Estimate Class: Class 3

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$17,884,761	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,884,761
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$17,884,761	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,884,761
Retirement Cost	$6,813,079										$6,813,079
Total Project Cost	$24,697,840	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,697,840

Asset Class: Customer Assets **Business Case ID:**2988

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**2988

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8529
Estimate Class: Class 3

Project Information

Name: 2022 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2022

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues. Regulation:
Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.
Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.
Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:
1) MXGI - meters due for sampling and exchange. (61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition. (7,500 units estimated)
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues(10,000 units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition (17,261 units estimated)
Resources: Lakeside Gas will perform the majority of this work.
Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure
Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,457,591	$18,270,259	165

Asset Class: Customer Assets

Estimate Class: Class 3

Business Case ID:8529

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$18,270,259	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,270,259
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$18,270,259	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,270,259
Retirement Cost	$7,003,973										$7,003,973
Total Project Cost	$25,274,232	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,274,232

Asset Class: Customer Assets **Business Case ID:**8529

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8529

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8531
Estimate Class: Class 3

Project Information

Name: 2023 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2023

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.
Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.
Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.
Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:
1) MXGI - meters due for sampling and exchange(61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition. (7,500 units estimated)
5) Resets (RS23) - rebuild of a meter set due to failure/condition/complianceissues. 10,000 (units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition. (17,261 units estimated)
Resources: Lakeside Gas will perform the majority of this work.
Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure
Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,470,603	$18,625,418	162

Asset Class: Customer Assets **Business Case ID:**8531

Estimate Class: Class 3

Cost

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Direct Capital Cost	$18,625,418	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,625,418
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$18,625,418	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,625,418
Retirement Cost	$7,162,659										$7,162,659
Total Project Cost	$25,788,077	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,788,077

Asset Class: Customer Assets **Business Case ID:**8531

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8531

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8532
Estimate Class: Class 3

Project Information

Name: 2024 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2024

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.
Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.
Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.
Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:
1) MXGI - meters due for sampling and exchange. (61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition(7,500 units estimated)
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues(10,000 units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition (17,261 units estimated)
Resources: Lakeside Gas will perform the majority of this work.
Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure
Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,532,295	$19,084,078	162

Asset Class: Customer Assets **Business Case ID:**8532

Estimate Class: Class 3

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$19,084,078	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,084,078
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$19,084,078	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,084,078
Retirement Cost	$7,426,898										$7,426,898
Total Project Cost	$26,510,976	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,510,976

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8533

Estimate Class: Class 3

Project Information

Name: 2025 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2025

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.

Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.

Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.

Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:

1) MXGI - meters due for sampling and exchange. (61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition (7,500 units estimated).
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues(10,000 units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition. (17,261 units estimated)

Resources: Lakeside Gas will perform the majority of this work.

Solution Impact:

1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure

Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,537,436	$19,129,269	162

Asset Class: Customer Assets

Business Case ID:8533

Estimate Class: Class 3

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$19,129,269	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,129,269
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$19,129,269	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,129,269
Retirement Cost	$7,758,183										$7,758,183
Total Project Cost	$26,887,452	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,887,452

Asset Class: Customer Assets **Business Case ID:**8533

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8533

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8534
Estimate Class: Class 3

Project Information

Name: 2026 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2026

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.
Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.
Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.
Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:
1) MXGI - meters due for sampling and exchange(61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition. (7,500 units estimated).
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues. (10,000 units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition. (17,261 units estimated)
Resources: Lakeside Gas will perform the majority of this work.
Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure
Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,577,217	$19,429,172	162

Asset Class: Customer Assets **Business Case ID:**8534

Estimate Class: Class 3

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$19,429,172	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,429,172
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$19,429,172	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,429,172
Retirement Cost	$7,365,245										$7,365,245
Total Project Cost	$26,794,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,794,417

Asset Class: Customer Assets **Business Case ID:**8534

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8534

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8535
Estimate Class: Class 3

Project Information

Name: 2027 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Project **Start Year:** 2027

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.
Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.
Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.
Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:
1) MXGI - meters due for sampling and exchange(61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated)
4) Vent aways (OG01)- work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition(7,500 units estimated)
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues(10,000 units estimated) 6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition (17,261 units estimated)
Resources: Lakeside Gas will perform the majority of this work.
Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure
Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,623,055	$20,053,027	160

Asset Class: Customer Assets

Estimate Class: Class 3

Business Case ID:8535

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$20,053,027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,053,027
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$20,053,027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,053,027
Retirement Cost	$7,785,369										$7,785,369
Total Project Cost	$27,838,396	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,838,396

Asset Class: Customer Assets **Business Case ID:**8535

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**8535

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**16144
Estimate Class: Class 3

Project Information

Name: 2028 Regulator & Meter Exchanges, Replacements, Resets, Vent Aways

Type: Enbridge Program **Start Year:** 2028

Asset Program: Regulator Refit

Project Type: Regulator / Meter Exchanges

Issue/Concern:

Meters: Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an Authorized Service Provider and adhere to Measurement Canada's accreditation standard S-A-01. Meters may also require exchange for issues such as: damages, leaks, customer billing issues.
Regulation: Regulators are the last line of defense for over-pressure to the customer. The condition of regulation systems is determined by regulator performance, corrosion of piping and regulators, and adherence to installation specifications. Failure of the regulation system can cause pressured gas to enter the premise, resulting in failure of gas equipment, loss of containment, and potentially fire or explosion.
Asset: Measurement Systems, Regulation, Safety Devices and Piping Systems.
Related Program: Meter Purchases

Compliance: Y

Solution Description:

Scope of Work:
1) MXGI - meters due for sampling and exchange(61,895 units planned)
2) MXGI regulator exchange - As a preventative measure, regulators are exchanged at the same time as the meter. Asset Management is in the process of optimizing regulator exchange frequency.
3) MXOT - meter exchanges due to damage/leak/failure/customer dispute(16,561 units estimated)
4) Vent aways (OG01) - work to ensure gas venting meet minimum clearances to building opening/air-intake/vent outlets/electrical sources to prevent migration/ignition(7,500 units estimated).
5) Resets (RS23) - rebuild of a meter set due to failure/condition/compliance issues (10,000 units estimated)
6) Regulator exchanges(RE00) - Regulator exchanges due to failure/age/condition (17,261 units estimated)

Resources: Lakeside Gas will perform the majority of this work.
Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Replacement of regulator asset before failure
3) Exchange of problematic meters
4) Ensuring compliance to vent clearance standards
5) Replacement of complete meter set to prevent failure and at failure
6) Replacement of regulators to prevent failure and at failure

Project Timing and Execution Risks: This is an annual program that spans the entire year.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,659,261	$20,047,700	162

Asset Class: Customer Assets

Business Case ID: 16144

Estimate Class: Class 3

Cost

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Direct Capital Cost	$20,047,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,047,700
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$20,047,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,047,700
Retirement Cost	$7,564,184										$7,564,184
Total Project Cost	$27,611,884	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,611,884

Asset Class: Customer Assets **Business Case ID:**16144

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**16144

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Appendix 7.2-6 – Real Estate & Workplace Services (REWS) Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Real Estate and Workplace Services **Business Case ID:**8677
Estimate Class: Class 5

Project Information

Name: Arnprior Operations Centre Obsolescence

Type: Enbridge Project **Start Year:** 2021

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: CONDITION: The Arnprior office is an owned property that is in good physical condition. The facility is challenged in its ability to meet required utilization and functionality, but is in a relatively good location for its workload. In addition, the existing furniture and finishings do not meet non-functional standards.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 3.82%. Therefore the physical condition of the facility meets EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 58% which is considered not to be correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.
Functional Obsolescence – Site: The site does meet operational requirements for size and vehicular circulation. The existing building requires expansion by approximately 5,183 square feet to meet the need for current staff and EGD functional requirements. The existing site is 6.1 acres, which meets EGD standards. There is enough space on the property to support a building addition, and the FCI/AI graph indicates a recommendation to repurpose the existing facility.
Asset: 249 Baskin Drive, Arnprior, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: ARNPRIOR FACILITY RENOVATION AND SITE IMPROVEMENT PROJECT
The project entails correcting physical and functional deficiencies by expanding the existing facility on the existing site. The current site has capacity to absorb the functional requirements. A 5,400 square foot expansion to the building comprising of administration, warehouse, welding and fabrication facilities will correct operational and workplace inefficiencies, use less energy, and emit less greenhouse gases. This expansion will extend the asset useful life by 25 to 40 years. The assets in scope are located at 249 Baskin Drive, Arnprior, ON. The nature of work includes interior renovation, furnishings and site improvements.
Expenditures: The total cost for the project is $2.1M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and using marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering as well as a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.
Solution Impact: The project entails correcting physical and functional deficiencies by expanding the existing facility on the existing site.
Project Timing and Execution Risks: The total project duration is 24 months as outlined below:
0 – 3 months: Programming and design development
3 – 9 months: Site plan agreement, permit and tender documents

6 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 22 months: Construction
22 – 24 months: Fit-up and occupancy

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	111,221	$2,100,000	70

Asset Class: Real Estate and Workplace Services **Business Case ID:** 8677

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$500,000	$1,600,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,100,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$500,000	$1,600,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,100,000
Retirement Cost	$210,000										$210,000
Total Project Cost	$710,000	$1,600,000	$0	$0	$0	$0	$0	$0	$0	$0	$2,310,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**8677

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**6104
Estimate Class: Class 5

Project Information

Name: Barrie Operations Centre Obsolescence

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: CONDITION: The Barrie office is a leased property that is in good physical condition. The facility is challenged in its ability to meet required utilization and functionality but is in a good location for its workload. In addition, the existing furniture and finishings do not meet non-functional standards.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 1.61%. Therefore, the physical condition of the facility meets EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 58%. Based on the FCI/AI graph, the current recommendation for the existing facility is to repurpose to accommodate current EGD standards.
Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard has only one point of access. The current yard size is 1.37 acres. EGD standard yard size is 2.5 acres. The facility is considered a satellite operations depot. Staff considers 1.37 acres as sufficient yard size for the type of operations in Barrie. It was noted by staff that EGD is planning in the future to relocate some staff from Barrie to a satellite depot in Orangeville. Overall, the existing building is too small to meet current EGD standards. The site and building are shared with another tenant. The limited yard area allocated to EGD causes operational and workplace difficulties and inefficiencies. The configuration of site functions and circulation is inefficient. There is only one point of vehicular access to the EGD yard. Building expansion on the same property will further reduce the size of the yard area and will cause additional pressure on parking and circulation. The existing building requires expansion by approximately 10,000 square feet to meet current EGD standards. A building addition on the property entails further reduction in the yard and parking areas. Current space pressures can be addressed by relocating staff to a new satellite operations depot in Orangeville and by acquiring the adjacent space currently occupied by the property landlord.
Asset: 10 Churchill Drive, Barrie, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This project entails purchasing the existing property in its entirety and expanding into the adjacent tenant space area. This strategy will ensure adequate yard area for current activities and by expanding into adjacent space, will correct the identified deficiencies to the administration, warehouse, welding, and fabrication areas. By doing so, less energy will be used, less greenhouse gases emitted and the expanded space will meet the current requirements of 17,000 square feet. The service life of the facility would be 25-40 years.
The assets in scope are located at 10 Churchill Drive, Barrie, ON. The nature of work includes improvements to the existing property and interior renovation and furnishings.
Expenditures: The total cost for the project is $7M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering as well as a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: Correcting functional deficiencies by expanding the existing facility
Project Timing and Execution Risks: The total project duration is 24 months as outlined below:
0 – 3 months: Programming, design development
3 – 6 months: Property acquisition
6 – 9 months: Permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award
14 – 20 months: Construction
20 – 24 months: Fit-up and occupancy

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	388,152	$7,000,000	85
Option 2		388,152	$9,800,000	61

Asset Class: Real Estate and Workplace Services **Business Case ID:**6104

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$1,000,000	$6,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$7,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,000,000	$6,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$7,000,000
Retirement Cost		$600,000									$600,000
Total Project Cost	$1,000,000	$6,600,000	$0	$0	$0	$0	$0	$0	$0	$0	$7,600,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**6104

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**6104

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**1796
Estimate Class: Class 5

Project Information

Name: Brampton Operations Centre Alterations

Type: Enbridge Project **Start Year:** 2016

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: CONDITION: The Colony Court office in Brampton is an owned property and has served Central Region West for over 10 years. The property is in relatively good physical condition but does not meet functionality/utilization requirements. In addition, the facility does not meet current building standards and operational requirements and the office space and yard is no longer sufficient to accommodate the current and future staffing needs of the operation. The majority of the furniture does not meet non-functional requirements.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 11.02%; therefore the physical condition of the facility does not meet EGD standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 49%. Based on the FCI/AI graph the current recommendation for the existing facility is to repurpose and invest to accommodate current EGD standards.
Functional Obsolescence – Site: The site does not meet operational requirements for vehicular circulation. The yard has only one point of access. The existing building requires expansion by approximately 9,000 square feet to meet the need for current staff and EGD functional requirements. Building additions on the property will entail reduction in the yard and parking areas, however the yard size will still be considered adequate based on current operations. Overall the existing building is too small to meet current EGD standards. The current building is approximately 14,250 square feet. An additional 9,000 square feet is required to accommodate office and industrial space.
Asset: 6 Colony Court, Brampton, ON.
Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: BRAMPTON FACILITY RENOVATION AND SITE IMPROVEMENTS PROJECT
The project entails correcting the physical and functional deficiencies by expanding the existing facility on the existing site. The site can be reconfigured to correct its functional inefficiencies and the existing structure can be expanded and reconfigured to meet current EGD standards. A 9,000 square foot expansion to the building comprising of administration, warehouse, welding, and fabrication facilities will correct operational and workplace inefficiencies, use less energy, and emit less greenhouse gases. This expansion will extend the asset useful life by 25 to 40 years. The assets in scope are located at 6 Colony Court, Brampton, ON. The nature of work for the project includes site improvements and facility expansion.

Expenditures: The total cost for the project is $5.3M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD projects. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services for the execution of similar projects.

Solution Impact: This project will correct physical and functional deficiencies by expanding and renovating the existing facility on the existing site.
Project Timing and Execution Risks: The project duration is 24 month as described below:
0 – 3 months: Programming and design development
3 – 9 months: Site plan agreement, permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 22 months: Construction
22 – 24 months: Fit-up and occupancy

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	454,565	$5,625,000	123
Option 2		454,565	$8,240,000	84

Asset Class: Real Estate and Workplace Services **Business Case ID:**1796

Estimate Class: Class 5

Cost

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Direct Capital Cost	$145,000	$280,000	$2,000,000	$100,000	$3,100,000	$0	$0	$0	$0	$0	$5,625,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$145,000	$280,000	$2,000,000	$100,000	$3,100,000	$0	$0	$0	$0	$0	$5,625,000
Retirement Cost	$0		$1,135,000		$500,000						$1,635,000
Total Project Cost	$145,000	$280,000	$3,135,000	$100,000	$3,600,000	$0	$0	$0	$0	$0	$7,260,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**8703
Estimate Class: Class 5

Project Information

Name: Brockville Operations Centre Obsolescence

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: CONDITION The Brockville office is an owned property that is in good physical condition, but does not meet required utilization and functionality. The property is relatively old with an approximate age of 46 years.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 7.53%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 84%, which is not considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.
Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard size is smaller than EGD standard yard size requirements. The current yard size is 0.69 acres. EGD standard yard size is 2.5 acres. The existing building requires expansion by approximately 6,000 square feet to meet the need for current staff and EGD functional requirements. Building an addition on the property will entail further reduction in the yard and parking areas. Overall the existing building is too small to meet current EGD standards. The undersized spaces, lack of proper locker rooms, lunch room, and muster room are not sufficient for staff and causes operational and workplace difficulties and inefficiencies. The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGD standards. Building expansion on the same property will further reduce the size of yard area, making it unusable and will impose additional pressure on parking and circulation.
Asset: 900 Centennial Road, Brockville, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The project entails selling the existing property, purchasing a vacant five acre industrial property, and building a new 10,000 square foot building. The new facility will house administration offices, warehouse, welding, and fabrication facilities and will correct operational and workplace inefficiencies, use less energy, and emit less greenhouse gases. This will ensure adequate yard area for current activities and a new building will correct the identified deficiencies thereby eliminating the identified risks. The service life of the new facility would be 25-40 years. After the new facility is occupied, the old facility will be disposed of.
The assets in scope are located at 900 Centennial Road, Brockville, ON. The nature of work is the development of a new property and the construction and fit-up of a new building.
Expenditures: The total cost for the project is $4.7M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs. Land values utilize marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering along with a constructor will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: This project will correct physical and functional deficiencies by building a new and improved facility.

Project Timing and Execution Risks: The project duration is 30 months as described below.
0-3 months: Programming and design development
3-6 months: Site acquisition
6-12 months: Site plan agreement, permit and tender documents, tender and award
12-14 months: Contract award and winter contingency as required
14-28 months: Construction
28-30 months: Fit-up and Occupancy Post occupancy disposition of property

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	235,104	$4,850,000	74

Asset Class: Real Estate and Workplace Services **Business Case ID:**8703

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$1,500,000	$3,350,000	$0	$0	$0	$0	$0	$0	$0	$0	$4,850,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,500,000	$3,350,000	$0	$0	$0	$0	$0	$0	$0	$0	$4,850,000
Retirement Cost		$100,000									$100,000
Total Project Cost	$1,500,000	$3,450,000	$0	$0	$0	$0	$0	$0	$0	$0	$4,950,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**8703

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3642
Estimate Class: Class 5

Project Information

Name: SMOC/Coventry Facility Consolidation

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern:
Coventry Road
The office building in Ottawa is an owned facility that is in physically fair condition. The facility's functionality is sound but there is excess space. In addition, the furniture and finishing's do not meet functional standards. The office is in a good location to serve the respective area, but there is duplication in coverage between the SMOC and Coventry Road facilities.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0, anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 43%, considered marginally correctable at current location without consideration of other factors including adequacy of land size and the Functional Condition Index.
Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation within the site. The yard size is smaller than EGD standard yard size requirements. The current yard size is 1.42 acres. EGD standard yard size is 2.5 acres. Building is in average condition Functionally sound (building has excess area)
The site does not meet non-functional standards (furniture standards, finishes etc.) The site is in a good location but is no longer optimized for best use. There is potential for consolidation with the SMOC facility on 90 Bill Leatham Drive, Nepean, ON.
SMOC
SMOC is an owned facility in physically fair condition. The facility's functionality is sound, however, there is unused/excess space. In addition, the furniture and finishings do not meet non-functional standards. The office is in a good location to serve its respective area, but there is duplication in coverage between this office and the office at Coventry Road.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. Anything between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index is 24% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the Functional Condition Index.
Functional Obsolescence – Site: The configuration of site functions and circulation is inefficient and poses a safety hazard. The yard area is too small to meet current EGD standards. The building is in average condition and is functionally sound (building has excess area).
The building does not meet non-functional standards (furniture standards, finishes etc.) It is in a good location but there is potential for consolidation with the Coventry Road facility.
Assets: 400 Coventry Road, Ottawa, ON, and 90 Bill Leatham Drive, Nepean, ON (SMOC)
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This project requires selling both the SMOC and Coventry Road properties, purchasing a property suitable in size (approximately seven acres) and building a new 70,000 square foot building that will consist of administration, warehouse, welding and fabrication facilities. The nature of work is development of a new property and the construction and fit-up of a new building.

Expenditures: The total cost for the Project is $23.8M net capital (as shown in Table 5-134) which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values using marketplace comparisons. The project also leverages national pricing agreements with furniture, wals, and flooring manufacturers. The Project costs are based on a Class 5 estimate.
Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.
Solution Impact: This option corrects operational and workplace inefficiencies by consolidating SMOC and Coventry redundancies. The new facility will use less energy and emit less greenhouse gases. The service life for the new facility will be 25-40 years.
Project Timing and Execution Risks:
The total Project duration is 30 months as described below:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
Post-occupancy disposition of property

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,168,605	$30,825,000	58

Asset Class: Real Estate and Workplace Services **Business Case ID:**3642
Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$25,000	$0	$0	$0	$0	$9,000,000	$19,000,000	$2,800,000	$0	$0	$30,825,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$25,000	$0	$0	$0	$0	$9,000,000	$19,000,000	$2,800,000	$0	$0	$30,825,000
Retirement Cost								$350,000			$350,000
Total Project Cost	$25,000	$0	$0	$0	$0	$9,000,000	$19,000,000	$3,150,000	$0	$0	$31,175,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**3642

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**8701
Estimate Class: Class 5

Project Information

Name: Kelfield Operations Centre Obsolescence.

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: CONDITION: The Kelfield office, owned by EGD, is in poor physical condition and is considered obsolete in its functionality and utilization. It is an old facility with an approximate age of 56 years.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 10.47%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable Enbridge EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 71%. Based on the FCI/AI graph, the current recommendation for the existing facility is to repurpose to accommodate current EGD standards.
Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. The yard has only one point of access. The yard size is smaller than EGD standard yard size requirements. The current yard size is 0.3 acres. EGD standard yard size is 2.5 acres. The existing building requires expansion by approximately 7,200 square feet to meet the need for current staff and EGD functional requirements. Building addition on the property entails further reduction in the yard and parking areas. Both the building and site area are too small to meet current EGD standards. The current building is approximately 7,724 square feet and the ideal building size, based on EGD design standards, is estimated to be 14,924 square feet, with a site area of approximately five acres. There is no opportunity for building expansion at the current location. It is understood that the location of the facility works well for EGD operations.
Asset: 40 Kelfield St, Etobicoke, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: KELFIELD FACILITY SITE ACQUISITION AND NEW BUILDING CONSTRUCTION PROJECT The purpose of the project is to increase the site area by purchasing the abutting property (0.5 acres and building), demolishing the existing buildings on site, and building a new two-storey 8,500 square foot building consisting of administration, warehouse, welding, and fabrication facilities. The new facility will correct operational and workplace inefficiencies, use less energy and emitting less greenhouse gases. The increase in yard size will alleviate the space problem by providing adequate yard area to support current activities. The service life of the new facility will be 25-40 years. The assets in scope are located at 40 Kelfield St, Etobicoke, ON. The nature of work is the development of the adjacent property, construction, and the fit-up of a new building.
Expenditures: The total cost for the project is $6.8M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering will be contracted from the marketplace. EGD has historically retained architectural and engineering consulting services for the execution of similar projects.

Solution Impact: Correcting physical and functional deficiencies by expanding and renewing the existing facility.

Project Timing and Execution Risks: The project duration is 36 months as described below:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit & tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Demolition of old building and remaining site activity

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	416,297	$6,800,000	91
Option 2		425,321	$9,600,000	66

Asset Class: Real Estate and Workplace Services **Business Case ID:**8701

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$1,000,000	$4,700,000	$1,100,000	$0	$0	$0	$0	$0	$0	$0	$6,800,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,000,000	$4,700,000	$1,100,000	$0	$0	$0	$0	$0	$0	$0	$6,800,000
Retirement Cost	$200,000										$200,000
Total Project Cost	$1,200,000	$4,700,000	$1,100,000	$0	$0	$0	$0	$0	$0	$0	$7,000,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**8701

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**8701

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services

Business Case ID:3639

Estimate Class: Class 5

Project Information

Name: Kennedy Road Expansion

Type: Enbridge Project

Start Year: 2022

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: CONDITION: Overall, the existing building at the Kennedy Road facility is too small to meet current EGD standards. The separation of offices and warehouse into two separate buildings is not convenient for staff and causes operational and workplace difficulties and inefficiencies. The configuration of site functions and circulation is inefficient. The yard area is too small to meet current EGD standards. Building expansion on the same property will further reduce the size of the yard area and will cause additional pressure on parking and circulation. Based on the site deficiencies and space limitations, relocation to another property is recommended. Although the Facility Condition Index (FCI) and Adequacy Index (AI) graph indicates recommendations to maintain and repurpose the existing facility, the site deficiencies, including space limitations and inefficiencies, will prevent the option of maintaining the existing building on the same property.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a FCI of 0 to 5%. The current FCI of the facility based on this study is 6.51%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility AI is 95%. Based on the FCI/AI graph, the current recommendation for the existing facility is to repurpose to accommodate current EGD standards.
Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. Access and exit from Kennedy is difficult and poses operational inefficiencies.The yard size is smaller than EGD standard yard size requirements. The current yard size is 1.3 acres. EGD standard yard size is 2.5 acres. The existing building requires expansion by approximately 11,000 square feet to meet the need for current staff and EGD functional requirements. Building additions on the property entail further reduction in the yard and parking areas.
Asset: 3157 Kennedy Road, Scarborough, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: KENNEDY SITE ACQUISITION AND NEW BUILDING CONSTRUCTION PROJECT
This project entails purchasing the adjacent property (approximately 2 acres), demolishing the existing buildings on site, and building a new 26,000 square foot building comprising of administration, warehouse, welding and fabrication facilities. The project will correct operational and workplace inefficiencies, use less energy, and emit less greenhouse gases on the combined site. This strategy will leverage current site improvements and keep land acquisition costs to a minimum by joining the currently vacant neighboring property. The service life of the new facility will be 25-40 years. The assets in scope are located at 3157 Kennedy Road, Scarborough, ON. The nature of work includes development of the adjacent property and construction and fit-up of a new building.
Expenditures: The total cost for the project is $19.7M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and estimated land values are based on marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services for the execution of similar projects.

Solution Impact: Correcting physical and functional deficiencies by renewing the existing facility.
Project Timing and Execution Risks: The project duration is 36 months as outlined below:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit & tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Demolition of old building and remaining site activity

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	1,281,711	$21,700,000	90
Option 2		1,281,711	$21,900,000	90

Asset Class: Real Estate and Workplace Services **Business Case ID:**3639

Estimate Class: Class 5

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$9,200,000	$8,000,000	$4,500,000	$0	$0	$0	$0	$0	$0	$0	$21,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$9,200,000	$8,000,000	$4,500,000	$0	$0	$0	$0	$0	$0	$0	$21,700,000
Retirement Cost			$500,000	$0							$500,000
Total Project Cost	$9,200,000	$8,000,000	$5,000,000	$0	$0	$0	$0	$0	$0	$0	$22,200,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**3639

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3639

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services | **Business Case ID:**6143

Estimate Class: Class 5

Project Information

Name: Peterborough Operations Centre Obsolescence

Type: Enbridge Project | **Start Year:** 2021

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: CONDITION: The EGD-owned Peterborough office is in moderate physical condition and is considered challenged in its functionality and utilization. It is a relatively older facility with an approximate age of 35 years.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 10.38%, therefore the physical condition of the facility does not meet EGD acceptable standards
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 32%. Based on the FCI/AI graph the current recommendation for the existing facility is to repurpose to accommodate current EGD standards.
Functional Obsolescence – Site: The yard size is smaller than EGD standard yard size requirements. The current yard size is 0.57 acres. EGD's standard yard size is 2.5 acres. The existing building requires expansion by approximately 3,300 square feet to meet the need for current staff and EGD functional requirements. Building additions on the property will entail further reduction in the yard and parking areas.
Asset: 572 Neal Drive, Peterborough, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: PETERBOROUGH FACILITY RELOCATION PROJECT
This project requires purchasing a vacant five acre industrial property and building a new 10,200 square foot facility. It will provide space for administration office space, warehousing, welding, and fabricating, will correct any workplace inefficiencies. The new facility will ensure adequate yard area for current activities and a new building will correct deficiencies, use less energy, and emit less greenhouse gases. The service life of the new facility would be 25-40 years. Once the new facility is occupied, the previous facility will be vacated. The assets in scope are located at 572 Neal Drive, Peterborough, ON.
Expenditures: The total cost for the project is $4.5M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services for the execution of similar projects.
Solution Impact: The project corrects physical and functional deficiencies by building a new and improved facility.
Project Timing and Execution Risks: The project duration is 30 months as described below:
0 – 3 months: Programming, design development, and location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required

14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy, post-occupancy disposition of property

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	204,815	$4,450,000	70

Asset Class: Real Estate and Workplace Services **Business Case ID:** 6143

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$1,000,000	$3,450,000	$0	$0	$0	$0	$0	$0	$0	$0	$4,450,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,000,000	$3,450,000	$0	$0	$0	$0	$0	$0	$0	$0	$4,450,000
Retirement Cost		$75,000									$75,000
Total Project Cost	$1,000,000	$3,525,000	$0	$0	$0	$0	$0	$0	$0	$0	$4,525,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**6143

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:** 6143

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3640
Estimate Class: Class 5

Project Information

Name: Station B New Building

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: CONDITION: The Station B office on Eastern Ave is an owned property in a good location, but does not meet current building standards or operational requirements. The physical condition is considered good, but the utilization and functionality is challenged. The office space no longer sufficiently accommodates current and future staffing needs of the facility.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 12.28%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 49%.
Functional Obsolescence – Site: The property is divided into two separate parts. The first part consists of approximately 0.7 acres completely fenced off, including a secure gate station located adjacent to the site on the northwest corner. The reminder of the site consists of 3.2 acres and is used as an operations depot. The site does not meet operational requirements for size and vehicular circulation. One point of access is provided to the site which poses circulation difficulties and poses operational inefficiencies. The yard size is marginally smaller than EGD standard yard size requirements. The current yard size is 2.25 acres. The EGD standard yard size is 2.5 acres. It was noted by EGD staff that the existing yard size is adequate for current operations. The existing building requires expansion by approximately 8,000 square feet to meet the need for current staff and EGD functional requirements.
Asset: 405 Eastern Avenue, Toronto, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The project entails demolishing the existing facility and building a new two-storey building, maintaining the area of the existing yard. This strategy will ensure adequate yard area for operational activities and a new 11,300 square foot building comprising of administration, warehouse, welding, and fabrication facilities that will correct operational and workplace inefficiencies, use less energy, and emit less greenhouse gases. The service life of the new facility would be 25-40 years, with the old building being demolished.
The assets in scope are located at 405 Eastern Avenue, Toronto, ON. The nature of work is site improvements and construction and fit-up of a new building.
Expenditures: The total cost for the project is $6.5M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD projects. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: Professional resources for design and engineering along with a contractor will be retained from the marketplace. Historically, EGD has engaged architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: Correcting physical and functional deficiencies by renewing the existing facility
Project Timing and Execution Risks: The project duration is 36 months as described below. 0-3 months: Programming and design development
3-9 months: Site plan agreement, permit and tender documents
9-12 months: Permit and tender process
12-14 months: Contract award and winter contingency as required
14-28 months: Construction
28-30 months: Fit-up and Occupancy
30-36 months: old building demolition and remaining site improvements

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	352,710	$6,500,000	83
Option 2		352,710	$11,400,000	47
Option 3		352,710	$14,500,000	37

Asset Class: Real Estate and Workplace Services **Business Case ID:**3640

Estimate Class: Class 5

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$5,000,000	$1,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$6,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$5,000,000	$1,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$6,500,000
Retirement Cost		$350,000									$350,000
Total Project Cost	$5,000,000	$1,850,000	$0	$0	$0	$0	$0	$0	$0	$0	$6,850,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**3640

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3640

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**8681
Estimate Class: Class 5

Project Information

Name: Thorold Regional Office Obsolescence, Building & Site

Type: Enbridge Project **Start Year:** 2025

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: The administrative office in Thorold is an owned property that is in physically good condition, but operating at full occupancy offering minimal room for growth. This office was last renovated 16 years ago and the environment is in need of a refresh. Since this renovation, EGD office standards have evolved and include a focus on natural light and views to the outdoors. The facility does not meet current EGD office standards. In addition, the parking lot at the Thorold administrative facility does not meet current standards or growth demands. The parking lot currently accommodates 127 vehicles and does not accommodate the growth requirements for both operations and administrative staff parking. During peak periods, such as training sessions, department meetings, and special events, staff is required to park off site due to the limited space. In the winter after heavy snow, up to 10 parking spaces are lost until the snow is hauled away offsite.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 59% which is marginally considered correctable at the current location, without consideration of other factors, including adequacy of land size and the FCI.
Functional Obsolescence – Site: The site does not meet operational requirements for vehicular circulation. The yard size is smaller than EGD standard yard size requirements. The current usable yard size is 1.7 acres. EGD standard yard size is 2.5 acres, however there is at least one acre of landscaped area that could be reconfigured to accommodate site deficiencies.
Asset: 100 Schmon Parkway, Thorold, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: THOROLD FACILITY RENOVATION AND SITE IMPROVEMENT PROJECT
This project will correct physical and functional deficiencies by renovating the current office space and expanding the parking lot. Physical and functional standards can be met more cost-effectively by renovating the current office space and site. The renovated facility will use less energy and emit less greenhouse gases. The renovation will extend the asset useful life by 15 years. The assets in scope are located at 100 Schmon Parkway, Thorold, ON. The nature of work is interior renovation and furnishings and expanding the employee parking lot.
Expenditures: Total capital expenditure for this project is estimated to be $6M which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.
Resources: Professional resources for design and engineering will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services for the execution of similar projects.

Solution Impact: This project will correct physical and functional deficiencies by renovating the current office space and expanding the parking lot.
Project Timing and Execution Risks: The project duration is 12 months as described below:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents

5 – 7 months: Award, tender and permit process
7 – 11 months: Construction
11 – 12 months: Fit-up and occupancy

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	N	1,645,513	$15,511,000	162
Option 2	Y	575,915	$6,000,000	138

Asset Class: Real Estate and Workplace Services **Business Case ID:**8681

Estimate Class: Class 5

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$200,000	$5,800,000	$0	$0	$0	$0	$0	$0	$0	$0	$6,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$200,000	$5,800,000	$0	$0	$0	$0	$0	$0	$0	$0	$6,000,000
Retirement Cost	$0	$600,000									$600,000
Total Project Cost	$200,000	$6,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$6,600,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**8681

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R2	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R2						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Real Estate and Workplace Services **Business Case ID:**8681

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0R2	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R2						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Real Estate and Workplace Services **Business Case ID:**3638

Estimate Class: Class 5

Project Information

Name: TOC EMEC Expansion

Type: Enbridge Project **Start Year:** 2017

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: The owned Technology and Operations Centre (TOC) office is in physically good condition and is offering good utilization overall. It is a new facility that was built and operationalized approximately four years ago. The one specific area requiring expansion is the Engineering Materials Evaluation Center (EMEC) facility at the TOC. EMEC's 10-year growth plan has been achieved within 24 months as a result of an increased focus on asset integrity. This rapid expansion was not anticipated during the facility's build.

Asset: 101 Honda Blvd (TOC) - EMEC

Related Program: N/A

Compliance: N

Solution Description:

TECHNOLOGY AND OPERATIONS CENTRE (TOC) EMEC EXPANSION PROJECT

Scope of Work:

This Project corrects current physical and functional deficiencies with an expansion of size of the existing facility. Because this is a relatively new facility, it is generally in compliance with current standards and therefore the current functional and physical deficiencies more easily correctable. It will deliver 6400 sq. ft. of expanded lab and warehouse facilities for material testing addressing operational and workplace inefficiencies as well as using less energy and emitting less greenhouse gases. The service life of the expanded and renovated materials evaluation centre would be 25 years. The assets in scope are at 101 Honda Boulevard, Markham, ON. The nature of work is expanding the EMEC lab space. The total Project duration is 24 months as described below:

0 – 3 months: Programming and design development

3 – 9 months: Site plan agreement, permit and tender documents

6 – 12 months: Permit and tender process

12 – 14 months: Contract award and winter contingency as required

14 – 22 months: Construction

22 – 24 months: Fit-up and occupancy

Expenditures

The total cost for the Project is $2.4M net capital. Construction costs are determined based on historical EGD project costs. The Project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The Project costs are based on a Class 5 estimate. The $2.4M net capital budget estimate includes a working construction cost contingency of 15%.

Resources

Professional resources for design and engineering will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services for the execution of similar type projects.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	321,626	$4,350,000	99

Asset Class: Real Estate and Workplace Services **Business Case ID:**3638
Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$200,000	$550,000	$50,000	$50,000	$3,500,000	$0	$0	$0	$0	$0	$4,350,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$200,000	$550,000	$50,000	$50,000	$3,500,000	$0	$0	$0	$0	$0	$4,350,000
Retirement Cost		$20,000	$0		$500,000						$520,000
Total Project Cost	$200,000	$570,000	$50,000	$50,000	$4,000,000	$0	$0	$0	$0	$0	$4,870,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**3638

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3638

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**6087

Estimate Class:

Project Information

Name: New Mechanical Services Building

Type: Enbridge Project **Start Year:** 2021

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: The fleet garage (Mechanical Services Building) located at VPC serves the entire GTA with a primary focus on fleet operations and heavy vehicles, construction equipment, pickup trucks, and smaller support vehicles. Fleet operations also support the installation and maintenance of Natural Gas Vehicle (NGV) equipment and requires substantial yard space for the maintenance, storage, and retirement of assets. The Mechanical Services Building was built in 1969 and is no longer capable of accommodating the volume and specialized needs of the operation. The expectation of replacement of the fleet facility delayed the expected life cycle replacements of the electrical, HVAC, building shell, overhead doors, and windows to meet current energy efficiency standards. Over the years, demand for passenger vehicle parking has also grown, limiting the parking lot capacity available for fleet garage operations. In addition, there are several safety issues regarding the mixed use nature of the VPC head office facility for both fleet and office functions on the same site. The addition of significant capital dollars to renew an inadequate and inefficient building shell on the existing site is not recommended.
CONDITION: The VPC facility houses the majority of company employees. It is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns as well as to replace legacy furniture and finishing. The first and second floors have not yet been renovated.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 5.59%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.
Functional Obsolescence – Site: The site area and parking provided are generally in compliance with EGD requirements.
Asset: Mechanical Services Building located at 500 Consumers Road, North York, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Mechanical Services Site Acquisition and New Building Construction Project
This project requires purchasing a vacant industrial property and building a new facility. This would ensure that the following functions are implemented:
-Site footprint is adequate for current activities
-Building deficiencies are corrected
-Current standards for both building and site coverage are met

The project requires purchasing a vacant five-acre industrial property and building a new 30,000 square foot building comprising of administration, fleet and heavy equipment facilities. Purchasing the extra land will ensure adequate yard area for current activities and a new building will correct the identified operational deficiencies, use less energy and emitting less greenhouse gases. Once the new facility is occupied, the old facility will be demolished. The service life of the new facility would be 25-40 years. The asset in scope is the Mechanical

Services Building located at 500 Consumers Road, North York, ON.
The nature of the work includes the design, construction, and fit-up a new building.
Expenditures: The total cost for the project is $9M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: Correcting physical and functional deficiencies by renewing the existing facility.
Project Timing and Execution Risks:
The project duration is 36 months as described below:
0 – 3 months: Programming, design development, location analysis
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit and tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 36 months: Fit-up and occupancy, demolition of old Mechanical Services Building

RISKS: Potential for building envelope failure. Destructive testing is planned during renovation opportunities to evaluate envelope integrity. There is a financial risk of loss of use without substantial life cycle improvement due to advanced age. Further financial risk is due to building deficiencies causing operational inefficiencies, leading to productivity loss. The existing facility uses more energy than a comparable new or renovated facility utilizing current Ontario Building Code (OBC) and energy standards. The existing facility emits more greenhouse gases than a comparable new or renovated facility utilizing current OBC and energy standards.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	793,787	$9,000,000	135

Asset Class: Real Estate and Workplace Services **Business Case ID:**6087
Estimate Class:

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$4,500,000	$4,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$9,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,500,000	$4,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$9,000,000
Retirement Cost		$550,000									$550,000
Total Project Cost	$4,500,000	$5,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$9,550,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**6087

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:** 6087

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3634
Estimate Class: Class 4

Project Information

Name: VPC-1

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: CONDITION: The VPC facility houses the majority of company employees. It is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns, as well as to replace legacy furniture and finishings. The first and second floors have not yet been renovated.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 5.59%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.
Functional Obsolescence – Site: The site area and parking provided are generally in compliance with EGD requirements.
Asset: First Floor, 500 Consumers Rd. Toronto, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The project corrects physical and functional deficiencies on the first floor of the tower by renovating and renewing the existing space. The current site has capacity to meet EGD functional requirements. Renovations to the building will correct operational and workplace inefficiencies, use less energy, and emit less greenhouse gases. The interior renovation will extend the asset useful life by 10 to 15 years. The assets in scope are the first floor at 500 Consumers Rd. Toronto, ON. The nature of work is interior renovation and furnishings.
Expenditures: The total cost for the project is $4.2M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: The project corrects physical and functional deficiencies on the first floor of the tower by renovating and renewing the existing space.
Project Timing and Execution Risks: The total project duration is 14 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents
5 – 7 months: Award, permit and tender process
7 – 12 months: Construction
12 – 14 months: Fit-up and occupancy

RISKS: Potential for building envelope failure. Destructive testing is planned during renovation opportunities to evaluate envelope integrity. There is a financial risk of loss of use without substantial life cycle improvement due to advanced age. Further financial risk is due to building deficiencies causing operational inefficiencies, leading to productivity loss. The existing facility uses more energy than a comparable new or renovated facility utilizing current Ontario Building Code (OBC) and energy standards. The existing facility emits more greenhouse gases than a comparable new or renovated facility utilizing current OBC and energy standards.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	478,265	$4,200,000	109

Asset Class: Real Estate and Workplace Services

Business Case ID:3634

Estimate Class: Class 4

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$4,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,200,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,200,000
Retirement Cost	$350,000										$350,000
Total Project Cost	$4,550,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,550,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3634

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**3635
Estimate Class: Class 5

Project Information

Name: VPC-B

Type: Enbridge Project **Start Year:** 2021

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: CONDITION: The VPC facility houses the majority of company employees. It is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns as well as to replace legacy furniture and finishings. The first and second floors have not yet been renovated.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 5.59%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.
Functional Obsolescence – Site: The site area and parking provided are generally in compliance with EGD requirements.
Asset: Basement, 500 Consumers Rd. Toronto, ON.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The project corrects physical and functional deficiencies on the basement floor of the VPC tower by renovating and renewing the existing space. The current site has capacity to meet EGD functional requirements. Renovations to the building will correct operational and workplace inefficiencies, use less energy, and emit less greenhouse gases. The interior renovation will extend the asset useful life by 10 to 15 years. The assets in scope are the basement floor at 500 Consumers Rd. Toronto, ON. The nature of work is interior renovation and furnishings.
Expenditures: The total cost for the project is $2M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values are determined using marketplace comparisons. The project also leverages national pricing agreements with furniture, wall, and flooring manufacturers. The project costs are based on a Class 5 estimate.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: The project corrects physical and functional deficiencies on the basement floor of the VPC tower by renovating and renewing the existing space.
Project Timing and Execution Risks: The total project duration is 14 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents
5 – 7 months: Award, permit and tender process
7 – 12 months: Construction
12 – 14 months: Fit-up and occupancy

RISKS: Potential for building envelope failure. Destructive testing is planned during renovation opportunities to evaluate envelope integrity. There is a financial risk of loss of use without substantial life cycle improvement due to advanced age. Further financial risk is due to building deficiencies causing operational inefficiencies, leading to productivity loss. The existing facility uses more energy than a comparable new or renovated facility utilizing current Ontario Building Code (OBC) and energy standards. The existing facility emits more greenhouse gases than a comparable new or renovated facility utilizing current OBC and energy standards.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	189,900	$2,000,000	91

Asset Class: Real Estate and Workplace Services

Business Case ID:3635

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000
Retirement Cost											
Total Project Cost	$2,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**3635

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services

Business Case ID:8782

Estimate Class: Class 5

Project Information

Name: VPC Core and Shell Obsolescence

Type: Enbridge Project

Start Year: 2024

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: The building shell and core for the VPC facilit are nearing 60 years. The tower building was constructed in or around 1968 as a two-storey building with an addition in 1978 that included floors 3 to 5.
CONDITION: The VPC facility houses the majority of company employees. It is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns as well as to replace legacy furniture and finishings. The first and second floors have not yet been renovated.
Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 5.59%. Therefore the physical condition of the facility does not meet EGD acceptable standards.
Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.
Functional Obsolescence – Site: The site area and parking provided are generally in compliance with EGD requirements.
Asset: 500 Consumers Rd, North York, ON
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This project calls for correcting physical and functional deficiencies by renovating and renewing the existing facility. This is the preferred strategy since the FCI and AI show the building and site deficiencies are correctable by the following activities:
-Renewing the building’s main mechanical system
-Adding two elevators
-Renovating the three main staircases
-Replacing the building cladding

These will correct operational and workplace inefficiencies by use less energy and emitting less greenhouse gases on the existing property. The service life of the renewed facility would be 40 years.
The assets in scope are located at 500 Consumers Rd, North York, ON. The nature of work is the removal and replacement of the 50-year old exterior envelope on the tower and the replacement of core mechanical and electrical systems.

Expenditures: The total cost for the project is $20M net capital. Construction costs are determined from facility assessment reports and architectural consultant budget forecasts and use marketplace comparisons. The project costs are based on a Class 5 estimate.
Resources: External professional resources for design and engineering as well as a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: Correcting physical and functional deficiencies by renovating and renewing the existing facility
Project Timing and Execution Risks:
The project duration is 24 months as described below:
0 – 3 months: Programming and design development
3 – 9 months: Permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 24 months: Construction

RISKS: Potential for building envelope failure. Destructive testing is planned during renovation opportunities to evaluate envelope integrity. There is a financial risk of loss of use without substantial life cycle improvement due to advanced age. Further financial risk is due to building deficiencies causing operational inefficiencies, leading to productivity loss. The existing facility uses more energy than a comparable new or renovated facility utilizing current Ontario Building Code (OBC) and energy standards. The existing facility emits more greenhouse gases than a comparable new or renovated facility utilizing current OBC and energy standards.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	N	2,180,437	$95,000,000	35
Option 2	Y	2,180,437	$20,000,000	157

Asset Class: Real Estate and Workplace Services **Business Case ID:**8782

Estimate Class: Class 5

Cost

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
Direct Capital Cost	$10,000,000	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$20,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$10,000,000	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$20,000,000
Retirement Cost	$1,000,000	$1,000,000									$2,000,000
Total Project Cost	$11,000,000	$11,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$22,000,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**8782

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R2					R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R2						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Real Estate and Workplace Services **Business Case ID:**8782

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R2					R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R2						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Real Estate and Workplace Services **Business Case ID:**8768
Estimate Class: Class 5

Project Information

Name: 2025 Blanket for Building Systems

Type: Enbridge Project **Start Year:** 2025

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: Capital projects are projected by gathering information provided from consultants, service contractors and maintenance staff. Some of equipment replacement factors are lifecycle of equipment, age of the building, limiting the risk of failure, safety concerns, building standards, compliance issues, and equipment failure. The determination from a failed piece of equipment will be the cost of repair versus the cost of replacement, with the factors listed above considered as well.
Asset: Various assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Life cycle improvements
Resources: Resources are a combination of internal maintenance staff and market-sourced external providers on a project by project basis. Workplace Services work closely with third party engineers, contractors/vendors in order to ensure the sustainability and energy demands of EGD's buildings.
Solution Impact: This Project ensures the sustainability and energy demand of EGD's buildings. The key focus is the design, installation, operation and monitoring of building systems that are required for the safe, comfortable and environmentally friendly operations.
Project Timing and Execution Risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	190,800	$2,029,625	106

Asset Class: Real Estate and Workplace Services **Business Case ID:**8768

Estimate Class: Class 5

Cost

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Direct Capital Cost	$2,029,625	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,029,625
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,029,625	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,029,625
Retirement Cost	$220,000										$220,000
Total Project Cost	$2,249,625	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,249,625

Asset Class: Real Estate and Workplace Services **Business Case ID:**8768

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**8768

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services

Business Case ID:8769

Estimate Class: Class 5

Project Information

Name: 2026 Blanket for Building Systems

Type: Enbridge Project

Start Year: 2026

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: Capital projects are projected by gathering information provided from consultants, service contractors and maintenance staff. Some of equipment replacement factors are life cycle of equipment, age of the building, limiting the risk of failure, safety concerns, building standards, compliance issues, and equipment failure. The determination from a failed piece of equipment will be the cost of repair versus the cost of replacement, with the factors listed above considered as well.
Asset: Various assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Life cycle improvements
Resources: Resources are a combination of internal maintenance staff and market-sourced external providers on a project by project basis. Workplace Services work closely with third party engineers, contractors/vendors in order to ensure the sustainability and energy demands of EGD's buildings.
Solution Impact: This Project ensures the sustainability and energy demand of EGD's buildings. The key focus is the design, installation, operation and monitoring of building systems that are required for the safe, comfortable and environmentally friendly operations.
Project Timing and Execution Risks: Annual program

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	194,101	$2,064,738	106

Asset Class: Real Estate and Workplace Services **Business Case ID:**8769

Estimate Class: Class 5

Cost

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Direct Capital Cost	$2,064,738	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,064,738
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,064,738	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,064,738
Retirement Cost	$200,000										$200,000
Total Project Cost	$2,264,738	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,264,738

Asset Class: Real Estate and Workplace Services **Business Case ID:** 8769

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**10046
Estimate Class: Class 5

Project Information

Name: 2027-28 Blanket for Building Systems

Type: Enbridge Project **Start Year:** 2027

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern: Capital projects are projected by gathering information provided from consultants, service contractors, and maintenance staff. Some of equipment replacement factors are: life cycle of equipment, age of the building, limiting the risk of failure, safety concerns, building standards, compliance issues, and equipment failure. The determination from a failed piece of equipment will be the cost of repair versus the cost of replacement, with the factors listed above considered as well.
Asset: Various assets.
Related Program: N/A

Compliance: N
Solution Description:
Scope of Work: Life cycle improvements
Resources: Resources are a combination of internal maintenance staff and market-sourced external providers on a project by project basis. Workplace Services work closely with third party engineers, contractors/vendors in order to ensure the sustainability and energy demands of EGD's buildings.
Solution Impact: This Project ensures the sustainability and energy demand of EGD's buildings. The key focus is the design, installation, operation and monitoring of building systems that are required for the safe, comfortable and environmentally friendly operations.
Project Timing and Execution Risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	398,333	$4,237,253	106

Asset Class: Real Estate and Workplace Services **Business Case ID:**10046

Estimate Class: Class 5

Cost

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
Direct Capital Cost	$2,100,458	$2,136,795	$0	$0	$0	$0	$0	$0	$0	$0	$4,237,253
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,100,458	$2,136,795	$0	$0	$0	$0	$0	$0	$0	$0	$4,237,253
Retirement Cost	$210,000	$213,000									$423,000
Total Project Cost	$2,310,458	$2,349,795	$0	$0	$0	$0	$0	$0	$0	$0	$4,660,253

Asset Class: Real Estate and Workplace Services **Business Case ID:**10046

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**10046

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**4333
Estimate Class: Class 3

Project Information

Name: Direct Capital Overheads

Type: Enbridge Project **Start Year:** 2017

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern: Direct contractor costs for capital projects
Asset: Contractor staff.
Related Program: N/A

Compliance: N
Solution Description:
Scope of Work: Contractor Staff

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	361,800	$3,645,000	72

Asset Class: Real Estate and Workplace Services **Business Case ID:**4333
Estimate Class: Class 3

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$530,000	$350,000	$530,000	$530,000	$530,000	$250,000	$250,000	$250,000	$250,000	$175,000	$3,645,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$530,000	$350,000	$530,000	$530,000	$530,000	$250,000	$250,000	$250,000	$250,000	$175,000	$3,645,000
Retirement Cost											
Total Project Cost	$530,000	$350,000	$530,000	$530,000	$530,000	$250,000	$250,000	$250,000	$250,000	$175,000	$3,645,000

Asset Class: Real Estate and Workplace Services **Business Case ID:**4333

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**4333

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Appendix 7.2-7 – Fleet & Equipment Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Fleet & Equipment

Estimate Class: Class 4

Business Case ID:3526

Project Information

Name: 2017- 2021 - 484 Light and Medium duty vehicles

Type: Enbridge Project

Start Year: 2017

Asset Program: Capital Purchase Program - Vehicles

Project Type: Other

Issue/Concern: Light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.
Asset: Light Duty vehicles and Medium Duty vehicles.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This project provides EGD with the necessary fleet vehicles to safely and efficiently run its business operations. The goal of the project is to maintain the integrity of all fleet assets for safe and reliable operation. This ongoing replacement strategy optimizes the asset life cycle, improves safety, and reduces risk for EGD and its employees. To help achieve this goal, the Fleet & Equipment department utilizes financial cost analysis, risk analysis, and physical asset assessment to guide replacement decisions
Resources: Fleet & Equipment staff
Solution Impact: To replace aging fleet assets, a report is generated by the fleet management analytical software tool Flagship Replace, which uses raw fleet data to identify all vehicles meeting the replacement criteria. The direct impact is reduced O&M repair and maintenance costs and improved driver safety.
Project Timing & Execution Risks: Annual program

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,474,495	$20,822,266	118

Asset Class: Fleet & Equipment **Business Case ID:**3526

Estimate Class: Class 4

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$4,653,574	$1,146,120	$5,068,514	$4,902,904	$5,051,154	$0	$0	$0	$0	$0	$20,822,266
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,653,574	$1,146,120	$5,068,514	$4,902,904	$5,051,154	$0	$0	$0	$0	$0	$20,822,266
Retirement Cost											
Total Project Cost	$4,653,574	$1,146,120	$5,068,514	$4,902,904	$5,051,154	$0	$0	$0	$0	$0	$20,822,266

Asset Class: Fleet & Equipment **Business Case ID:**3526

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**8548

Estimate Class: Class 4

Project Information

Name: 2022 to 2028 - 484 Light and Medium duty vehicles

Type: Enbridge Project **Start Year:** 2022

Asset Program: Capital Purchase Program - Vehicles

Project Type: Other

Issue/Concern: Light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.
Asset: Light Duty vehicles and Medium Duty vehicles.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Replace 500 existing light duty and 25 medium duty vehicles over the next five years.
Resources: Fleet & Equipment staff
Solution Impact: To replace aging fleet assets, a report is generated by the fleet management analytical software tool Flagship Replace, which uses raw fleet data to identify all vehicles meeting the replacement criteria. The direct impact is reduced O&M repair and maintenance costs and improved driver safety.
Project Timing & Execution Risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	3,151,328	$32,510,774	80
Option 2	N	2,234,428	$20,227,265	112

Asset Class: Fleet & Equipment

Business Case ID: 8548

Estimate Class: Class 4

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$4,652,374	$4,871,000	$4,585,500	$4,495,400	$4,635,500	$4,635,500	$4,635,500	$0	$0	$0	$32,510,774
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,652,374	$4,871,000	$4,585,500	$4,495,400	$4,635,500	$4,635,500	$4,635,500	$0	$0	$0	$32,510,774
Retirement Cost											
Total Project Cost	$4,652,374	$4,871,000	$4,585,500	$4,495,400	$4,635,500	$4,635,500	$4,635,500	$0	$0	$0	$32,510,774

Asset Class: Fleet & Equipment **Business Case ID:**8548

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**8548

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**9554
Estimate Class: Class 5

Project Information

Name: NG conversion kits for new fleet vehicles

Type: Enbridge Project **Start Year:** 2018

Asset Program: Capital Purchase Program - Vehicles

Project Type: Other

Issue/concern: EGD continues to operate a bi-fuel fleet; this purchase is necessary to acquire natural gas (NG) kits for all new fleet vehicles.
Asset: NG Conversion kits and associated Fleet assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Purchase and install NG kits for new vehicles.
Resources: Fleet & Equipment staff
Solution Impact: Converting EGD vehicles to operate on natural provides significant savings by reducing the fleet fuel expense. Also, having a bi-fuel fleet gives EGD the advantage of being able to operate if there is a power outage and the commercial service stations are not available.
Project Timing & Execution Risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$4,673,516	0

Asset Class: Fleet & Equipment

Business Case ID:9554

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$370,000	$399,514	$407,504	$415,654	$423,967	$432,446	$586,190	$535,303	$546,009	$556,929	$4,673,516
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$370,000	$399,514	$407,504	$415,654	$423,967	$432,446	$586,190	$535,303	$546,009	$556,929	$4,673,516
Retirement Cost											
Total Project Cost	$370,000	$399,514	$407,504	$415,654	$423,967	$432,446	$586,190	$535,303	$546,009	$556,929	$4,673,516

Asset Class: Fleet & Equipment **Business Case ID:**9554

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**9554

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**8555
Estimate Class: Class 4

Project Information

Name: 2022 to 2028 - 485 Heavy Work Equipment

Type: Enbridge Project **Start Year:** 2022

Asset Program: Capital Purchase Program - Equipment & Materials

Project Type: Heavy Work Equipment

Issue/concern: Heavy Work Equipment replacement, units which are much older and worn. Individual equipment assessed using the fleet Flagship Replace application.
Asset: Various Heavy Duty Equipment assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Replace 86 existing heavy work equipment over the next five years.
Resources: Fleet & Equipment staff
Solution Impact: The fleet management analytical software tool Flagship Replace is used to make informed replacement decisions for rolling equipment such as backhoes. Replacement decisions for non-rolling equipment (i.e. welders) are primarily based on age, hour meter, and physical condition. Once heavy equipment assets reach an age of 10 years, a physical assessment is conducted to evaluate the equipment. A comparison of the maintenance history is used to determine refurbish or replace decisions. The Heavy Work Equipment Project mitigates such risks by reducing O&M repair and maintenance costs, improving productivity, and addressing operator safety.

Project Timing & Execution Risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	494,438	$4,224,950	125
Option 2	N	494,438	$9,161,841	58

Asset Class: Fleet & Equipment **Business Case ID:**8555

Estimate Class: Class 4

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$500,000	$453,801	$741,300	$621,600	$636,083	$636,083	$636,083	$0	$0	$0	$4,224,950
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$500,000	$453,801	$741,300	$621,600	$636,083	$636,083	$636,083	$0	$0	$0	$4,224,950
Retirement Cost											
Total Project Cost	$500,000	$453,801	$741,300	$621,600	$636,083	$636,083	$636,083	$0	$0	$0	$4,224,950

Asset Class: Fleet & Equipment **Business Case ID:**8555

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Fleet & Equipment **Business Case ID:**8555

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Fleet & Equipment **Business Case ID:**3546
Estimate Class: Class 4

Project Information

Name: 2017 -2021 - 486 Tools & Equipment

Type: Enbridge Project **Start Year:** 2017

Asset Program: Capital Purchase Program - Tools

Project Type: Other

Issue/Concern: Our tools and equipment have to meet new approved technologies and all legislation. As well as, existing old worn out or obsolete tools and equipment can pose potential safety issues to our employees performing their job duties and to the public.
Asset: Various tools and equipment assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: All company tools are in scope for this project such as electric drills, concrete saws, and personal gas monitors. The tool replacement strategy is based on the physical condition of the asset, tool obsolescence, and/or new mandatory legislation. With approximately 5000 pieces, the Fleet & Equipment department tracks the majority of the tool inventory and asset information in a FleetFocus database.
Resources: Fleet & Equipment Staff
Solution Impact: Depending on the tool, condition is assessed when repairs are required. There is no defined inspection schedule for the majority of small tools. Replacement decisions are reactive based on tool condition and estimated repair cost. Failure of aging tools presents both a safety risk to the employee and a financial risk to EGD. The Tools and Equipment Project mitigates such risks by reducing O&M repair and maintenance costs, improving productivity, and addressing operator safety.
Project Timing & Execution risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	0	$4,249,976	0

Asset Class: Fleet & Equipment **Business Case ID:**3546
Estimate Class: Class 4

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$1,570,103	$279,873	$800,000	$800,000	$800,000	$0	$0	$0	$0	$0	$4,249,976
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,570,103	$279,873	$800,000	$800,000	$800,000	$0	$0	$0	$0	$0	$4,249,976
Retirement Cost											
Total Project Cost	$1,570,103	$279,873	$800,000	$800,000	$800,000	$0	$0	$0	$0	$0	$4,249,976

Asset Class: Fleet & Equipment **Business Case ID:**3546

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**3546

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment

Estimate Class: Class 4

Business Case ID:8549

Project Information

Name: 2022 to 2028 - 486 Tools & Equipment

Type: Enbridge Project

Start Year: 2022

Asset Program: Capital Purchase Program - Tools

Project Type: Tools

Issue/Concern: Our tools and equipment have to meet new approved technologies and all legislation. As well as, existing old worn out or obsolete tools and equipment can pose potential safety issues to our employees performing their job duties and to the public.
Asset: Various tools and equipment assets.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: All company tools are in scope for this project such as electric drills, concrete saws, and personal gas monitors. The tool replacement strategy is based on the physical condition of the asset, tool obsolescence, and/or new mandatory legislation. With approximately 5000 pieces, the Fleet & Equipment department tracks the majority of the tool inventory and asset information in a FleetFocus database.
Resources: Fleet & Equipment staff
Solution Impact: Depending on the tool, condition is assessed when repairs are required. There is no defined inspection schedule for the majority of small tools. Replacement decisions are reactive based on tool condition and estimated repair cost. Failure of aging tools presents both a safety risk to the employee and a financial risk to EGD. The Tools and Equipment Project mitigates such risks by reducing O&M repair and maintenance costs, improving productivity, and addressing operator safety.
Project Timing & Execution Risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	0	$7,000,000	0

Asset Class: Fleet & Equipment **Business Case ID:**8549

Estimate Class: Class 4

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$0	$0	$0	$7,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$0	$0	$0	$7,000,000
Retirement Cost											
Total Project Cost	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$0	$0	$0	$7,000,000

Asset Class: Fleet & Equipment **Business Case ID:**8549

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**8549

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Appendix 7.2-8 – Technology & Information Services (TIS) Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Information Technology **Business Case ID:**5583
Estimate Class: Class 5

Project Information

Name: CIS Hardware Replacement

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

The hardware platform currently utilized for the SAP CIS solution needs to be refreshed; it has not been refreshed since 2013 and the manufacturer warranty of the hardware has expired. The current hardware for the CIS SAP environment is now out of warranty. Failure to refresh aging infrastructure puts our business at risk with an increased chance of service outages, degraded performance, increased cost and difficulty in acquiring support and replacement parts, as well as an operational expense of $650K annually for extended hardware maintenance. In addition, the current hardware is incompatible with the new generation of SAP software, SAP S/4 HANA; failure to replace the hardware will prevent any future CIS software upgrades.

Asset: CIS hardware platform
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Procure the hardware required to replace the existing technology, as per the specifications based on the sizing of the current application, the technology standards (HANA) required by the vendor, and the data tiering strategy for best performance and scalability as was implemented for the SAP BW. Once hardware has been received in the two data centres, professional services from the hardware vendor will be utilized to install and configure the hardware, and external and internal resources will migrate the existing CIS system to the new hardware. Approach: this is primarily a procurement of hardware initiative, but standard TIS project management methodology will be followed, including a signed charter and project plan, covering the activities of design, build, test and implementation.
Resources: hardware vendor professional services, internal resources and external contractors as required.

Solution Impact: This Program provides for the refresh of the equipment utilized by the Customer Information System (CIS) as per the recommended five year replacement cycle.
Project Timing and Execution Risks:

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	3,431,847	$10,000,000	118

Asset Class: Information Technology **Business Case ID:**5583

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$0	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$0	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000
Retirement Cost											
Total Project Cost	$0	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000

Asset Class: Information Technology **Business Case ID:**5583

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**5583

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**9341
Estimate Class: Class 5

Project Information

Name: Customer Care Information System (CIS) Business Solutions (2019 -2021)

Type: Enbridge Program **Start Year:** 2019

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

This business case is to address the capital requirement for the Customer Care Information System (CIS) releases. The CIS releases are required to implement enhancements to include but not limited to CIS, Swift, and MVRS systems to ensure customer satisfaction, compliance and continued supportability. This allows the systems to meet ongoing business requirements in the Customer Care and Operations business areas (meter-to-cash process, customer emergency response process, etc), support any regulatory requirements, and continue to ensure systems supportability.

Asset:
Related Program:

Compliance: Y

Solution Description:

Scope of Work: CIS was implemented in September 2009 and CIS serves 2 million customers. The CIS releases are in alignment with the strategic areas of Productivity, Safety and Reliability, Regulatory, and Customer Satisfaction. The scope of the CIS releases is to implement customer raised functionality, changing regulatory requirements, enhancements raised to accommodate projects having an impact to the customer care systems, and regular system upgrades.
• Customer Raised Functionality – Changes required to address issues customers are experiencing using CIS. These types of issues can range from minor changes to large enhancements.
• Regulatory Changes – Changing/new regulatory requirements impacting customer billing, customer safety and compliance, etc. (Example: upcoming billing changes related to Carbon Backstop)
• Project Required Changes – Projects may require CIS to be modified to achieve their project objectives such as: WAMS releases, community expansions required billing changes, Incremental Capital Module required billing changes, Geothermal required billing changes, etc.
• Recurring System Changes – These changes include QRAM updates, Deferral Variance, annual system updates, etc.
• Technical Enhancements and Upgrades – these are required to ensure systems remain fully supported and under vendor support; this includes upgrades to SWIFT and replacing server NT168 used for Reporting.
Approach: This project addresses changes and updates to CIS and Customer Care related systems. Standard TIS project management methodology will be followed, including a signed charter and project plan, covering the activities of design, build, test and implementation.
Resources: Software vendor professional services, internal resources and external contractors as required.
Solution Impact: This Program will provide and maintain IT support to the EGD Customer Care group. Computer hardware and software that is approaching end-of-life will be updated and/or replaced to satisfy evolving business needs and to mitigate operational risks.
Project Timing and Execution Risks: This is an annual program until 2021.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	298,140	$2,400,000	91

Asset Class: Information Technology **Business Case ID:**9341

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$400,000	$400,000	$800,000	$800,000	$0	$0	$0	$0	$0	$0	$2,400,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$400,000	$400,000	$800,000	$800,000	$0	$0	$0	$0	$0	$0	$2,400,000
Retirement Cost											
Total Project Cost	$400,000	$400,000	$800,000	$800,000	$0	$0	$0	$0	$0	$0	$2,400,000

Asset Class: Information Technology **Business Case ID:**9341

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**9341

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8683

Estimate Class: Class 5

Project Information

Name: Customer Experience Transformation (Digital) (includes all business cost and Accenture cost)

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

This program is a customer satisfaction and financial opportunity to implement changes to SAP, the EGD extranet, and other customer-facing solutions to improve the overall customer experience. Opportunities include but are not limited to:

- Meter Reading & Late Stage Collection (Finance)
- Near Real-Time Payments
- Outgoing Payment Channel
- Unify QPM to SAP
- Digital Payments Self-Service (Payment Options)
- Customer Preference Centre
- Interactive Bill /Multi Channel Bill Design
- Energy Use Insights, Cross-Selling & Campaigns
- Web Assistant / Web Chat
- Omni-Channel
- CRM Assessment
- CRM Implementation
- CS&C Interactions
- Real-Time Notifications
- Credit and Collection Effectiveness
- Changes to the extranet to meet on-going regulatory, business, cutomer requirements
- Analytics capabilities to analyze customers, channel, campaign/program data (assume start in 2017)

Assets: various assets in the customer space; extranet, enhancments to SAP CIS, new applications such as MMR, BDex, Chatbot Attachment: Customer Experience Program

Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This program is a customer satisfaction and financial opportunity to implement changes to SAP, Extranet and other customer facing solution to improve the overall customer experience. This is a multi-year program; see attachment for a high-level roadmap. (The high-level roadmap is intended to illustrate planned program scope; project priority and timelines will be determined during yearly program planning).

2018 Scope:

- Extranet rewrite (Web 1.0 & 2.0): Implement SAP MCF integration; re-platform from Tridion to Sitecore CMS; implement concierge experience online, interactive bill, online appointment scheduling
- Implement Mobile Meter Reading & improve Late Stage Collection process
- Implement BDex for back-office exception management (replacement of EMMAX)
- Bill Estimation: Leverage analytics & AI to improve bill estimation consistency and accuracy

- Appointment Notifications: Implement appointment notification through SMS and email for non-program work
- Bill reformat: Implement new bill design to align with EGD branding –
- Chatbot Design - Design select use cases for implementation in 2019
- Agent UX - Design CRM screens to enable agent next best actions

The high-level initiatives for the 2019 roadmap include but are not limited to:

- Web & Social Chat: Implement Web Chatbot & Live Chat
- Optimize Core Customer Service & Billing: Budget Billing Standardization; Enhance Agent UX/CRM (fact sheet, NBA, customer 360 view); High Bill Analyzer; Move, Credit & Collection Optimization
- Enhanced Online Experience: Changes to the EGD extranet to enable a new preference centre, develop/enhance B2C & B2B portals; enhance LBA online experience
- Optimize Field: extend appointment scheduling for MyAccount; enable MXGI scheduling online
- Call Prediction/Personalized IVR: IVR – SAP MCF integration to support dynamic IVR and increase self-serve
- Mobile Meter Reading Phase 2 - enhance the solution to enable customers to complete self reads using OCR technology
- Analytics: Continue to build on analytics capabilities to analyze customers, channels, campaign/program data; build customer analytical records and models; build and refresh dashboards

Approach: each track will follow the standard TIS project management methodology, including a signed charter and approved project plan covering the design, build, testing and implementation phases
Project list and estimated benefits --> This is a list of 2018 completed/in-flight projects and 2019 Projects in high level planning phase as of August 2018; attachment also includes anticipated annual benefits of each projects where possible.
Resources: Internal TIS and Customer Care staff, Accenture functional and technical consultants, Deloitte partners for technology solutioning, other external contractors as required.
Solution Impact: The resulting benefits will be realized through call volume reduction, eBill adoption/reduce paper bill enrollments and work automation. O&M savings in Customer Care is expected to be $3M-$5M each year from 2018 - 2020.
Project Timing and Execution Risks: Project execution between 2018-2019. See Scope of work for detailed breakdown.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	6,860,000	$21,800,000	132

Asset Class: Information Technology **Business Case ID:**8683

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$14,800,000	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$21,800,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$14,800,000	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$21,800,000
Retirement Cost											
Total Project Cost	$14,800,000	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$21,800,000

Asset Class: Information Technology **Business Case ID:**8683

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8683

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8683
Estimate Class: Class 5

Project Information

Name: Customer Experience Transformation (Digital) (includes all business cost and Accenture cost)

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

This program is a customer satisfaction and financial opportunity to implement changes to SAP, the EGD extranet, and other customer-facing solutions to improve the overall customer experience. Opportunities include but are not limited to:

- Meter Reading & Late Stage Collection (Finance)
- Near Real-Time Payments
- Outgoing Payment Channel
- Unify QPM to SAP
- Digital Payments Self-Service (Payment Options)
- Customer Preference Centre
- Interactive Bill /Multi Channel Bill Design
- Energy Use Insights, Cross-Selling & Campaigns
- Web Assistant / Web Chat
- Omni-Channel
- CRM Assessment
- CRM Implementation
- CS&C Interactions
- Real-Time Notifications
- Credit and Collection Effectiveness
- Changes to the extranet to meet on-going regulatory, business, cutomer requirements
- Analytics capabilities to analyze customers, channel, campaign/program data (assume start in 2017)

Assets: various assets in the customer space; extranet, enhancments to SAP CIS, new applications such as MMR, BDex, Chatbot Attachment: Customer Experience Program
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This program is a customer satisfaction and financial opportunity to implement changes to SAP, Extranet and other customer facing solution to improve the overall customer experience. This is a multi-year program; see attachment for a high-level roadmap. (The high-level roadmap is intended to illustrate planned program scope; project priority and timelines will be determined during yearly program planning).
2018 Scope:

- Extranet rewrite (Web 1.0 & 2.0): Implement SAP MCF integration; re-platform from Tridion to Sitecore CMS; implement concierge experience online, interactive bill, online appointment scheduling
- Implement Mobile Meter Reading & improve Late Stage Collection process
- Implement BDex for back-office exception management (replacement of EMMAX)
- Bill Estimation: Leverage analytics & AI to improve bill estimation consistency and accuracy

- Appointment Notifications: Implement appointment notification through SMS and email for non-program work
- Bill reformat: Implement new bill design to align with EGD branding –
- Chatbot Design - Design select use cases for implementation in 2019
- Agent UX - Design CRM screens to enable agent next best actions

The high-level initiatives for the 2019 roadmap include but are not limited to:

- Web & Social Chat: Implement Web Chatbot & Live Chat
- Optimize Core Customer Service & Billing: Budget Billing Standardization; Enhance Agent UX/CRM (fact sheet, NBA, customer 360 view); High Bill Analyzer; Move, Credit & Collection Optimization
- Enhanced Online Experience: Changes to the EGD extranet to enable a new preference centre, develop/enhance B2C & B2B portals; enhance LBA online experience
- Optimize Field: extend appointment scheduling for MyAccount; enable MXGI scheduling online
- Call Prediction/Personalized IVR: IVR – SAP MCF integration to support dynamic IVR and increase self-serve
- Mobile Meter Reading Phase 2 - enhance the solution to enable customers to complete self reads using OCR technology
- Analytics: Continue to build on analytics capabilities to analyze customers, channels, campaign/program data; build customer analytical records and models; build and refresh dashboards

Approach: each track will follow the standard TIS project management methodology, including a signed charter and approved project plan covering the design, build, testing and implementation phases
Project list and estimated benefits --> This is a list of 2018 completed/in-flight projects and 2019 Projects in high level planning phase as of August 2018; attachment also includes anticipated annual benefits of each projects where possible.
Resources: Internal TIS and Customer Care staff, Accenture functional and technical consultants, Deloitte partners for technology solutioning, other external contractors as required.
Solution Impact: The resulting benefits will be realized through call volume reduction, eBill adoption/reduce paper bill enrollments and work automation. O&M savings in Customer Care is expected to be $3M-$5M each year from 2018 - 2020.
Project Timing and Execution Risks: Project execution between 2018-2019. See Scope of work for detailed breakdown.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	6,860,000	$21,800,000	132

Asset Class: Information Technology **Business Case ID:**8683

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$14,800,000	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$21,800,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$14,800,000	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$21,800,000
Retirement Cost											
Total Project Cost	$14,800,000	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$21,800,000

Asset Class: Information Technology **Business Case ID:**8683

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8925
Estimate Class: Class 5

Project Information

Name: IT - 00 - Desktop Replacement (2018 - 2028)

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

Replace end user computing devices (laptops, desktops, field devices) that are out of warranty and at end-of-life as per the asset life cycle strategy. Inability to replace units will result in significant productivity challenges for EGD personnel, as laptops will break down and suffer significantly degraded performance. In addition, laptops must be compatible with current operating software; for 2018 and 2019, this relates to Windows 10.
Assets: TIS - Hardware (laptops, some desktops, ruggedized field laptops)- each year's number of replacements will be different as warranties expire.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This project includes procurement of the devices required in the particular calendar year, the configuration, scheduling and deployment of the devices to the impacted users, and the cost of desktop technicians required to perform the rollouts.
Approach: standard TIS project management methodology will apply, including a signed charter and approved project plan for each calendar year, including procurement and rollout activities.
Resources: As Project commences at the start of each year, the necessary resources are identified and purchased to perform the rollouts as per the project plan for that year.
Solution Impact: This Project is in place to avoid significant operating costs due to the breakdown of aging devices along with the costs required to repair and to avoid productivity losses due to older equipment failing and being unable to keep up with operating system and software advances.
Project Timing and Execution Risks: This is an annual program.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	776,355	$4,945,000	114

Asset Class: Information Technology **Business Case ID:**8925

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$500,000	$870,000	$2,000,000	$1,575,000	$0	$0	$0	$0	$0	$0	$4,945,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$500,000	$870,000	$2,000,000	$1,575,000	$0	$0	$0	$0	$0	$0	$4,945,000
Retirement Cost											
Total Project Cost	$500,000	$870,000	$2,000,000	$1,575,000	$0	$0	$0	$0	$0	$0	$4,945,000

Asset Class: Information Technology **Business Case ID:**8925

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:** 8925

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**5968
Estimate Class: Class 5

Project Information

Name: WAMS stabilization & releases (2018 - 2027)

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:
This business case is for enhancements and upgrades to support safety, business and regulatory needs and also to keep application systems current with required infrastructure and software versions.

Asset: TIS - Software (Software packaged)

Related Program: N/A

Compliance: N
Solution Description:
Scope of Work: Making the necessary changes to the WAMS suite of systems / delivering solutions leveraging WAMS suite of systems as per business needs and priorities; keeping the system current with required infrastructure and software version upgrades.
The following activities are the high level enhancements that are being planned for during the business case period:

- Implementation of changes/enhancements requested by business stakeholders to support business operations
- Implementation of Maximo G/L
- Implementation of Record Correction Management in WAMS
- Implementation of Schedule Optimization
- Integration with Asset Investment Planning
- Integration with Asset Risk Assessment
- Integration with a project management tool
- Implementation of inventory and materials management (link to materials traceability project)
- Implementation of Fleet management
- Implementation of Meter management
- WAMS integration with engineering procedures
- WAMS system upgrades
- Implementation of ClickMobile Touch
- Implementation of Customer Engagement (digital interface with customers via web, smart device, and even loyalty programs)
- Scheduling dashboards
- Improved EA scheduling and coordination
- Long cycle jobs
- Service Edge upgrade (next version of ClickSoftware's Service Optimization Suite)
- Click patches and version upgrades

Approach: Standard TIS project management approach, including a signed charter for each calendar year, and other project management deliverables (i.e. project plan, resource plan, test plans, implementation plans) to support the design, build, test and implementation phases of each year.

Resources: PM, BA, data architect, developers/support analysts, QA personnel and any necessary external contractors and vendor partners.
Solution Impact: Upgrades and enhancements to support safety, business and regulatory needs and to maintain an application system current with required infrastructure and software versions.
Project Timing and Execution Risks: Annual program until 2021.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	338,646	$11,300,000	111

Asset Class: Information Technology **Business Case ID:**5968

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$2,800,000	$2,500,000	$3,000,000	$3,000,000	$0	$0	$0	$0	$0	$0	$11,300,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,800,000	$2,500,000	$3,000,000	$3,000,000	$0	$0	$0	$0	$0	$0	$11,300,000
Retirement Cost											
Total Project Cost	$2,800,000	$2,500,000	$3,000,000	$3,000,000	$0	$0	$0	$0	$0	$0	$11,300,000

Asset Class: Information Technology **Business Case ID:**5968

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							R0
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							R0
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**5968

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years						R0	
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years				R0			
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8927

Estimate Class: Class 5

Project Information

Name: IT - 00 - Microsoft Enterprise Agreement (2018 - 2027)

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

This is a contractual agreement with Microsoft that must be honoured. We enter into three year Microsoft Enterprise Agreements in order to be able to continue using the Microsoft suite at EGD: Office, Outlook, SharePoint, Skype, etc.

Assets: Multiple Microsoft software assets (different counts for each)
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: This project is the annual payment of the Microsoft Enterprise Agreement (EA). The EA provides "software assurance" which allows us to upgrade EGD's Microsoft license assets as new versions of the software are released by Microsoft without additional cost. The EA is a 3-year agreement. A payment is due in each of the three years based on the licensed assets owned by Enbridge at the beginning of the agreement. True-up payments are also made annually as new licensed assets are acquired, and are covered in this project. Contractual obligations and use of the software assets in the calendar year require payment in that year. This is a procurement project only, performed by Enbridge TIS, typically executed in February (payment) and December (true-up).
Resources: This is strictly a procurement activity so no resourcing is required for this Program.
Solution Impact: This Program addresses the significant productivity and financial consequences that would exist if the products covered under this agreement were not utilized.
Project Timing and Execution Risks: Annual program.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,062,320	$5,100,000	72

Asset Class: Information Technology **Business Case ID:**8927

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$1,200,000	$1,300,000	$1,300,000	$1,300,000	$0	$0	$0	$0	$0	$0	$5,100,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,200,000	$1,300,000	$1,300,000	$1,300,000	$0	$0	$0	$0	$0	$0	$5,100,000
Retirement Cost											
Total Project Cost	$1,200,000	$1,300,000	$1,300,000	$1,300,000	$0	$0	$0	$0	$0	$0	$5,100,000

Asset Class: Information Technology **Business Case ID:**8927

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8927

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**5584

Estimate Class: Class 5

Project Information

Name: HANA Software Implementation

Type: Enbridge Project **Start Year:** 2019

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

The opportunities realized by proceeding with this project are the enablement of capabilities identified as part of the Customer Experience Road Map.

Additional benefits:

- The implementation of new functionality based on "best run" industry business model (i.e faster call center response fewer customer calls, increased customer self-serve adoption)
- Improved, standardized and simplified processes: i.e budget billing optimization Support for Multiple Channels Customer Interaction, for improved customer satisfaction and call-center calls reduction
- Best-in-class user interface for customers and CSRs
- Streamlined and simplified CRM processes
- Real-time analytics that support customer segmentation and real-time view into the business
- Scalable and technologically advanced system capable of supporting cloud and hybrid architectures and future merger expansions.

Risks of not implementing the S/4Hana project:

- Accumulation of Technical Debt (old software and hardware, stagnant processes, old-fashioned customer interaction) resulting in increasing operating cost.
- Status quo brings the risk of not meeting customer expectation or incurring unnecessary capital cost for developing capabilities otherwise included into the standard S/4HANA deployment.
- Deteriorating reliability and availability of the CIS system due to aging software.
- End-of-life vendor support on the existing version by 2025.
- Increased operational maintenance of the CIS platform, including maintaining support from the vendor; the longer we wait to patch / upgrade maintenance, the more complex maintaining the system gets
- SAP is moving to HANA as their primary data storage (DB) platform and we will have to align to their roadmap to maintain support and receive upgrades.

Asset: HANA software

Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The scope of work includes:

-Migration of the SAP solution for CIS to the SAP S/4 HANA version of the suite of products from SAP that are used for CIS: ECC, CRM and XI.

-Procurement of the HANA software licensing. Design of the storage solution that uses a tiering system for performance and capacity strategies.

-Migration of the CIS solution from the existing software version to the new HANA software solution, including the development of the implementation/migration plan and the significant amount of QA/testing required to validate the new solution.
Resources: BA, SAP development/support personnel, Business clients, PM. Deloitte resources as well as in-house TIS resources would be used.

Solution Impact: Provides supported and current infrastructure for our CIS system, and meets the vendor strategic roadmap for the hardware and software platforms.
Project Timing and Execution Risks: 2019: Risks include BU cost pressures and resource constraints.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	2,400,000	$10,400,000	168

Asset Class: Information Technology **Business Case ID:** 5584

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$6,400,000	$4,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$10,400,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,400,000	$4,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$10,400,000
Retirement Cost											
Total Project Cost	$6,400,000	$4,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$10,400,000

Asset Class: Information Technology **Business Case ID:**5584

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:** 5584

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**6049
Estimate Class: Class 5

Project Information

Name: Asset Management IT

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

Issue/Concern: Please see 2019+ AM Program Business Case.pdf attachment for complete details.
This Business Case is primarily meant to provide funds for the Asset Analytics Platform and PowerPlan enhancements.

This business case is to enhance and expand Asset Management toolsets as identified in ISO55000 as enabled by the following initiatives:

1. Asset Lifecycle Costing Analysis: This initiative will leverage the work done through Activity Based Costing, and the data available in Oracle and Maximo to establish the lifecycle cost of assets – starting with pipe and stations but ultimately extending the practice to all asset classes.
2. Project Portfolio Optimization: (a business case already exists for this initiative – 15803) For 2019, a set of configuration changes (identified in 2017) will be implemented. Further improvements to support the optimization of Capital and O&M across all asset classes will be specified in 2018 for implementation in 2019 (gas carrying assets) and 2020 (non-gas carrying).
3. Risk Management: Current tools meet existing needs. As new asset classes are brought into asset management scope, or new risks need to be monitored, there will be an ongoing need to enhance the tools.
4. Improve Performance Monitoring: KPI's have been established in 2017 to monitor the effectiveness of certain processes core to asset management effectiveness, delivery to plan, RROI, etc. These will evolve and ultimately include KPIs for asset performance and delivery to plan against targets. In the short term this will be developed using existing tools (Excel, Powerpoint, etc.) but over time a dashboard will be established that draws information from the appropriate SOR .
5. ERP-AIP Integration: There are multiple systems involved in from the optimization and ultimate approval of business cases, to the setup in Maximo, re-forecasting in IDF/COMMS, and reporting of actuals through Maximo. As part of Enterprise Resource Planning, there should be opportunity to integrate across these systems to avoid duplicate input and multiple SORs. Limited changes are expected until the enterprise-wide ERP is nearing completion, or this will be addressed through that initiative
6. Asset Analytics Platform: Asset analytics tools and architecture will be developed including a comprehensive set of tools to analyze data and a generalized data platform on which to base tools and models that support asset decision making.
7. Asset Management Decision Support: Develop multiple tools to bring information together and support asset decisions
8. Repair/Replace Methodology: Leverage life cycle modeling work, and asset data (including condition) to make repair/replace decisions – either for planned work or for immediate field-based decisions.
9. Integration of Asset Performance and Operational Technology Data: As the asset management concepts mature, both performance issues of assets and functional failures need to be captured to estimate the overall impact on business. For each asset class these "soft" failures have to be clearly defined and tracked in order to incorporate on the asset management framework.
10. Asset Management Process Repository: Development and population of a repository to hold AM-related process assets (standards, policies, processes, procedures.
11. Asset Metadata Repository
12. Data Quality Assessment and Improvement - Gas Carrying Assets
13. Data Quality Assessment and Improvement - Non-Gas Carrying Assets 14. Master Data Management -

Transmission Pipe

Asset: Asset Management applications.
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: Note that this project/program's costs have been reduced to include one release per year plus required asset analytics work. The remainder of the work will be scheduled as integration costs. Please see the attachment 2019+ AM Program Business Case for Solution Description details.
This Program is to enhance and expand Asset Management toolsets. This includes: Asset Lifecycle Costing Analysis, Project Portfolio Optimization, ERP-AIP Integration, Asset Management Decision Support.

Resources: Multiple resources are required for each initiative including: PM, BA, technical lead, developer, architect, and a business resource.

Solution Impact: Each initiative is different, however, the general principle is that the implementation of these projects will enable an improved view into EGD asset data and enhanced decision support.

Project Timing and Execution Risks:Timing of all initiatives varies from 2018-2028 as per the program roadmap. Execution risks include resource availability, availability of funds, and changing business priorities.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	4,528,618	$3,250,000	480

Asset Class: Information Technology **Business Case ID:**6049

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$850,000	$800,000	$800,000	$800,000	$0	$0	$0	$0	$0	$0	$3,250,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$850,000	$800,000	$800,000	$800,000	$0	$0	$0	$0	$0	$0	$3,250,000
Retirement Cost											
Total Project Cost	$850,000	$800,000	$800,000	$800,000	$0	$0	$0	$0	$0	$0	$3,250,000

Asset Class: Information Technology **Business Case ID:**6049

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**6049

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**3255

Estimate Class: Class 5

Project Information

Name: SCADA Replacement Project

Type: Enbridge Project **Start Year:** 2017

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

The current SCADA system is going out of support and will not be supported by Liquid Pipelines any longer, which means that the SCADA system will likely not be supported for Gas Distribution by 2021. The SCADA system replacement is dependent on the regulatory MAADs decision, as well as decisions as to overall SCADA direction pertaining to the gas distribution business.

Asset: SCADA System.
Related Program: N/A

Compliance: Y

Solution Description:

Scope of Work: Replace the existing SCADA system and move to the same platform that Union Gas utilizes today: Cygnet. This will include the replacement of the core SCADA application and options used by Gas Control and the replacement of the SCADA web which is currently leveraged by other departments throughout GD. Develop a support model based on multiple tenants going forward.
Approach: Standard TIS project management methodology will be followed, including a signed charter and project plan, covering the activities of design, build, test and implementation.
Resources: Software vendor professional services, internal resources and external contractors as required.
Solution Impact: This project will mitigate potential significant risks related to safety, finance and reputation by avoiding the continued use of outdated hardware and software.
Project Timing and Execution Risks: The Project began in 2016 and continued through 2017 with implementation expected to be concluded in 2019.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,830,621	$3,450,000	158

Asset Class: Information Technology **Business Case ID:**3255

Estimate Class: Class 5

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$950,000	$0	$2,500,000	$0	$0	$0	$0	$0	$0	$0	$3,450,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$950,000	$0	$2,500,000	$0	$0	$0	$0	$0	$0	$0	$3,450,000
Retirement Cost											
Total Project Cost	$950,000	$0	$2,500,000	$0	$0	$0	$0	$0	$0	$0	$3,450,000

Asset Class: Information Technology **Business Case ID:**3255

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**3255

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8551
Estimate Class: Class 5

Project Information

Name: SAP BW Enhancements

Type: Enbridge Project **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:
Need to maintain and enhance the SAP Business warehouse platform to meet existing and future operational business needs. Complete ongoing upgrades to the SAP Business Warehouse (BW on HANA) platform, in alignment with SAP CIS solution roadmap and EGD's CIS systems upgrade and replacement cycle. Continue development of capabilities and improve business analytics within SAP BW on HANA, to address business needs and address strategies such as improving customer satisfaction. Enhance overall BW performance by utilizing new HANA in-memory computing and current BW platform functionalities.

Asset: TIS - Software (Software packaged)
Related Program: N/A

Compliance: Y
Solution Description:
Scope of Work: Complete ongoing upgrades to the SAP Business Warehouse (BW on HANA) platform, in alignment with SAP CIS solution roadmap and EGD's CIS systems upgrade and replacement cycle. Continue development of capabilities and improve business analytics within BW on HANA, to address business needs and address items such as improving customer satisfaction. Enhance overall BW performance by utilizing HANA in-memory computing and current BW platform functionalities. Note that necessary hardware upgrades will be scheduled and completed in alignment with the CIS solution roadmap.

Approach: Standard TIS project management approach, including a signed charter and detailed project plan for each calendar year where funding is available, along with other TIS project deliverables such as risk, resource and implementation plans

Resources: Project resources will include a PM, BA, data architect, developers/support analysts and QA personnel.

Solution Impact: This Program provides for the upgrades of systems and hardware for the SAP Business Warehouse (BW) platform to maintain solution capabilities and align with the long-term strategy for delivery of reporting and data analytics services on customer data.
Project Timing and Execution Risks:
Systems performance improvement plan:
2018: Implement a set of functional enhancements to the SAP BW environment, focused on the creation of new reports and analytics of customer data.
2019: Enhance platform capabilities and add business analytics including the CTDS layer to be ready for customer datamart retirement and the addition of an external node for dynamic tiering.
2021: Procurement, installation, configuration and implementation of the next generation of hardware required for the SAP BW platform

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Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	1,407,548	$5,375,000	90

Asset Class: Information Technology **Business Case ID:**8551

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$175,000	$200,000	$0	$5,000,000	$0	$0	$0	$0	$0	$0	$5,375,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$175,000	$200,000	$0	$5,000,000	$0	$0	$0	$0	$0	$0	$5,375,000
Retirement Cost											
Total Project Cost	$175,000	$200,000	$0	$5,000,000	$0	$0	$0	$0	$0	$0	$5,375,000

Asset Class: Information Technology **Business Case ID:** 8551

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8551

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8602
Estimate Class: Class 5

Project Information

Name: Operation Digital

Type: Enbridge Project **Start Year:** 2019

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

Ensure that engineering documents (policies, procedures, standards, and processes) are compliant to both regulatory and standards that follow process safety policies and have well defined procedures as it pertains to work on EGD assets. Reduce costs in creating, maintaining, and delivery of engineering documents while still remaining compliant. Improve the readability of engineering documents so that they can be more easily understood and followed in order to reduce safety incidents. Improve the overall delivery and consumption of engineering Document content to both internal and external EGD stakeholders. Establish a governance structure so that engineering documents are kept up to date and meet regulatory standards and compliance.

Asset: TIS - Software (Software packaged)
Related Program: N/A

Compliance: N

Solution Description:

Scope of Work: The solution would include tools to perform the transformation of engineering documentation into a format where it can be re-used, with an ease of updates and a consistent look and feel. In addition, the new engineering content framework will require a publishing mechanism to allow for consumption of the content in various situations faced by operations. The consumers of engineering documentation also include Extended Alliance partners.
Approach: Standard TIS project management approach, including a signed charter and approved project plan for each calendar year, encompassing the design, build, test and implementation phases

Resources: PM, BA, data architect, developers/support analysts and QA personnel.
Solution Impact: See issue/concern for details on the opportunities through solutioning.
Project Timing and Execution Risks: This project will be carried out over three years.

Solution Options

OPTIONS				
OPTION NAME	**SELECTED OPTION**	**RISK MITIGATED**	**TOTAL NET DIRECT CAPITAL**	**LRROI**
Option 1	Y	3,735,488	$5,300,000	188

Asset Class: Information Technology **Business Case ID:**8602

Estimate Class: Class 5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$1,300,000	$3,000,000	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$5,300,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,300,000	$3,000,000	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$5,300,000
Retirement Cost											
Total Project Cost	$1,300,000	$3,000,000	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$5,300,000

Asset Class: Information Technology **Business Case ID:**8602

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8602

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**17943
Estimate Class: Class 5

Project Information

Name: IT Business Applications Upgrades, Enhancement Projects, Infrastructure Upgrades (2022-2028)

Type: Enbridge Project **Start Year:** 2022

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

Company's IT needs - Business as usual.
Assets: Various IT assets.
Related Program (if applicable): N/A

Compliance: N

Solution Description:

Scope of Work:
The IT Capital forecast from 2022 – 2028 is developed based on the Company's annual historical IT spend and IT and Business needs
These needs includes Business Applications Solutions and Upgrades, Enhancements Projects, and Desktop Infrastructure Procurement and Upgrades
Solutions and Upgrades involve acquiring and installing current versions of software specific to a particular business department (s) or process. These solutions and upgrades are necessary to sustain the reliability, security, availability, supportability, and maintainability of business systems and applications that are critical to operations at EGD
Enhancements are those projects that leverage existing systems to add or extend functionalities to meet the evolving needs of the departments within EGD
IT Desktop Infrastructure supports the entire organization. Examples of this include desktop/laptop computers, printers and productivity software
The forecast budgets related to business solutions and hardware and software procurements and upgrades are necessary and must be part of on-going upgrade /replacement cycles to ensure reliability, security, availability, and supportability of IT assets – which directly support EGD operations.
All IT equipment and software is purchased (rather than being leased) to avoid O&M costs. The Company's purchasing strategies include competitive RFPs and RFQs, as well as leveraging company size, with the goal of purchasing equipment and software at competitive rates.
Resources:
Solution Impact:
Project Timing and Execution Risks:
The detailed integration planning of the systems and processes of the two utilities is underway. The resulting integrated structure will influence the ultimate systems and processes spending.

Solution Options

OPTIONS

OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI

Option 1	Y	0	$154,989,002	0

Asset Class: Information Technology **Business Case ID:**17943
Estimate Class: Class 5

Cost

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Direct Capital Cost	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$0	$0	$0	$154,989,002
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$0	$0	$0	$154,989,002
Retirement Cost											
Total Project Cost	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$22,141,286	$0	$0	$0	$154,989,002

Asset Class: Information Technology **Business Case ID:**17943

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Information Technology **Business Case ID:**17943

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Appendix 7.2-9 – Business Development Business Cases (≥$2M)

EGD Asset Management Plan 2019-2028

Appendix

Company: Enbridge Gas Distribution

Owned by: Asset Management Department

Controlled Location: Asset Management Teamsite

Asset Class: Business Development **Business Case ID:**9552
Estimate Class: Class 5

Project Information

Name: NGT Existing customer Maintenance Capital - (Until 2026)

Type: Enbridge Project **Start Year:** 2018

Asset Program: NGV

Project Type: Compressor Equipment

Issue/Concern:

Maintenance capital for refueling stations for external customer stations only
Issue/concern: EGD fleet operators can continue to achieve fuel cost savings and reduced emission benefits by investing in the wellbeing of the NGV station. This can be achieved by adopting and continuously upgrading their NGV equipment as part of the maintenance strategy. By upgrading major NGV equipment, EGD can extend the life cycle of the equipment, resulting in a more cost-effective way of operating the NGV stations.

Assets: There are a number of current NGV stations successfully the EGD maintains, including:

- Truk-King
- City of Toronto - Bermondsey Yard
- City of Toronto - Ellesmere Yard
- 20 EGD Yards and Gate Stations

In addition, there are a number of confirmed new NGV customer station that will need to be maintained as well as a number of potential stations that EGD's marketing department have been working with customers to install. These customers are:

- City of Toronto - Ingram Yard (confirmed for 2018)
- Park N Fly (potential for 2019-2020)
- UPS Kanata (potential for 2019-2020)
- TTC (potential for 2019-2020)
- Canadian Tire Corp (potential for 2019-2020)

Related Program: N/A

Compliance: N

Solution Description:

Maintain customer equipment as per company standards and equipment manufacturer recommendations.

Scope of Work: The scope includes the rebuilding and upgrading of major equipment with new and improved technology for installed stations. This includes the following:

- Electrical power and control system;
- Gas dryer
- Gas compressor
- Above-ground piping and tubing
- Storage cylinders
- Fuel control panels

- Dispensers

Resources: Due to the scope and scale of the maintenance program, EGD will be required to utilize the services of outside contractors for the construction and maintenance of some stations. The maintenance program, drawing approval, and oversight will be undertaken by EGD.

Solution Impact: The adoption of maintenance planning offers a number of benefits to EGD and EGD rental customers:
• Assets perform at optimum levels, reducing service disruptions and losses due to asset failure
• The costs of asset maintenance can be quantified and budgeted with confidence
• The performance of the asset can be reviewed to suit service delivery needs • The plan provides a foundation for continuous improvement

Project Timing & Execution Risks:

- City of Toronto – Ellesmere (upgrade) (2018 planning and execution)
- City of Toronto - Ingram Yard (2018 planning and execution)
- New Customers (from potential list) (2019-2022 planning and execution) Timing and go-ahead for project depends heavily on the commitment from potential customers. Currently there are three potential customers in discussions with the marketing group for NGV servicing; however the number could potentially grow as new customers become interested.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	395,944	$2,668,100	108

Asset Class: Business Development **Business Case ID:**9552

Estimate Class: Class 5

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$276,527	$281,311	$286,178	$291,128	$296,165	$301,289	$306,501	$311,803	$317,198	$0	$2,668,100
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$276,527	$281,311	$286,178	$291,128	$296,165	$301,289	$306,501	$311,803	$317,198	$0	$2,668,100
Retirement Cost											
Total Project Cost	$276,527	$281,311	$286,178	$291,128	$296,165	$301,289	$306,501	$311,803	$317,198	$0	$2,668,100

Asset Class: Business Development **Business Case ID:**9552

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Business Development **Business Case ID:**9553
Estimate Class: Class 5

Project Information

Name: NGT Maintenance Capital for company/fleet NG refueling stations (2021 to 2028)

Type: Enbridge Project **Start Year:** 2021

Asset Program: NGV

Project Type: Compressor Equipment

Issue/Concern:

Maintenance capital for refueling stations for EGD NGT Fueling stations only
Issue/concern: The EGD Fleet department can achieve fuel cost savings and reduced emission benefits by operating the 800-plus fleet vehicles on natural gas versus diesel or gasoline. This presents an opportunity for the EGD Fleet Department to realize fuel savings and promotes the use of natural gas to other fleet operators as an alternate source for fueling vehicles at a lower cost with lower emissions. By demonstrating the use of natural gas, EGD can achieve growth in the marketplace, while realizing fuel savings.

Assets: EGD currently operates 19 Natural Gas Vehicle (NGV) fueling stations on company yards. The stations includes; Arnprior Yard, Barrie Yard, Beamsville Yard, Thorold Office, Brampton, Brockvill yard, Ottawa Office, Kelfield yard, Kennedy Road Yard, Midland Gate Station, Oshawa Office, Port Colbourne Yard, Peterborough yard, Shelburne Gate Station, South Merivall, Station B, Stayner Gate Station, Enbridge Training Centre, and the VPC Office. In addition, EGD will installing two new NGT stations to fuel recently converted vehicles and dedicated light duty trucks. These two new stations (Tecumseh Storage facility and Tallman Truck Center (Kemptville)) will also, need to be maintained.

Related Program: N/A

Compliance: N

Solution Description:

M252720UCM - NGV Utility Compressor Stations
Scope of Work: The scope includes the entire build and installation of a new NGV station at all EGD yards within the service area. The scope includes the design, procurement, construction and commissioning of the NGV refueling stations assets, as follows:
Design: Outsourcing to an experienced consulting engineering company for the design of the fueling stations
Procurement: The purchase of all of the NGV fueling equipment including the:

- Eelectrical power and control system
- Gas dryer
- Gas compressor
- Above ground piping and tubing
- Underground piping
- Storage cylinders
- Fuel control panels- Dispensers
- Fill pressure control system

Construction & Commissioning: Construction of the NGV station including all civil, mechanical and electrical works

- Commissioning of the stations

Resources: Due to the scope and scale of the project, EGD will be required to utilize the services of outside contractors for design, construction and maintenance. Engineering, approval, and drawings oversight will be undertaken by EGD.

Solution Impact: By providing NGV fueling equipment to customers on a rental basis, EGD can achieve growth in the marketplace, while fully recovering costs.

Project Timing & Execution Risks:

- City of Toronto - Ellesmere(upgrade) (2018 planning and execution)
- City of Toronto - Ingram Yard (2018 planning and execution)
- New Customers (from potential list) (2019-2022 planning and execution) Timing and go-ahead for project depends heavily on the commitment from potential customers. Currently there are three potential customers in discussions with the marketing group for NGV servicing; however the number could potentially grow as new customers become interested.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	684,666	$2,726,301	155

Asset Class: Business Development

Business Case ID: 9553

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$419,134	$461,773	$294,530	$299,625	$304,808	$310,082	$315,446	$320,903	$0	$0	$2,726,301
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$419,134	$461,773	$294,530	$299,625	$304,808	$310,082	$315,446	$320,903	$0	$0	$2,726,301
Retirement Cost											
Total Project Cost	$419,134	$461,773	$294,530	$299,625	$304,808	$310,082	$315,446	$320,903	$0	$0	$2,726,301

Asset Class: Business Development **Business Case ID:** 9553

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Business Development **Business Case ID:**9553

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0R1		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1		R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Business Development **Business Case ID:**2367
Estimate Class: Class 5

Project Information

Name: NGV Rental Compressors - Ex Transit - (Until 2020)

Type: Enbridge Program **Start Year:** 2016

Asset Program: NGV

Project Type: Other

Issue/Concern:

Fleet operators can achieve fuel cost savings and reduced emission benefits by operating their vehicles on natural gas versus diesel or gasoline. This presents an opportunity to grow EGD's NGV rental refueling business and promotes the use of natural gas to customers as an alternate source for fueling vehicles at a lower cost with lower emissions. By providing NGV fueling equipment to customers on a rental basis, EGD can achieve growth in the marketplace, while fully recovering costs.

Assets: There are a number of current NGV customers that EGD is successfully servicing, including:

- Truk-King
- City of Toronto - Bermondsey Yard - City of Toronto
- Ellesmere Yard - City of Toronto etc.

In addition, there are a number of confirmed new NGV customers that need to be serviced, as well as a number of potential customers that EGD's marketing department have been working with. These customers are:

- City of Toronto - Ellesmere Yard (Upgrade) (confirmed for 2018)
- City of Toronto - Ingram Yard (New Installed) (confirmed for 2018)
- Park N Fly (potential for 2019-2020)
- UPS Kanata (potential for 2019-2020)
- TTC (potential for 2019-2020)
- Canadian Tire Corp (potential for 2019-2020)

Related Program (if applicable): Once stations are installed and/or upgraded, they require maintenance to be performed. The associated BC for the maintenance work on existing stations is: BC#2369 & 9553.

Compliance: N

Solution Description:

M252720RCM - NGV Rental Compressors. This is the business case for NGT projects for the rental of CNG fuelling stations. The extension of this project is BC #8550. This category is for rental stations for garbage truck, highway tractor and shunt truck fleets, etc.

Scope of Work: The scope includes the entire build and install of a new NGV station for confirmed customers. The scope includes the design, procurement, construction and commissioning of the NGV refueling stations assets, as follows:
Design: Outsourcing to an experienced consulting engineering company for the design of the transit fueling stations
Procurement: The purchase of all of the NGV fueling equipment including the :

- electrical power and control system

- Gas dryer
- Gas compressor
- Above-ground piping and tubing
- Underground piping
- Storage cylinders
- Fuel control panels
- Dispensers
- Fill pressure control system

Construction & Commissioning: Construction of the NGV station including all civil, mechanical and electrical works

- Commissioning of the stations

Resources: Due to the scope and scale of the project, EGD will be required to utilize the services of outside contractors for the design, construction and maintenance. Engineering, construction approval, and oversight will be undertaken by EGD.

Solution impact: By providing NGV fueling equipment to customers on a rental basis, EGD can achieve growth in the marketplace, while fully recovering costs.

Project Timing & Execution risks:

- City of Toronto – Ellesmere (upgrade) (2018 planning and execution)
- City of Toronto - Ingram Yard (2018 planning and execution)
- New Customers (from potential list) (2019-2022 planning and execution) Timing and go-ahead for project depends heavily on the commitment from potential customers. Currently there are three potential customers in discussions with the marketing group for NGV servicing; however the number could potentially grow as new customers become interested.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	3,939,947	$18,500,000	89

Asset Class: Business Development **Business Case ID:**2367

Estimate Class: Class 5

Cost

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Direct Capital Cost	$3,100,000	$2,100,000	$5,100,000	$2,600,000	$5,600,000	$0	$0	$0	$0	$0	$18,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$3,100,000	$2,100,000	$5,100,000	$2,600,000	$5,600,000	$0	$0	$0	$0	$0	$18,500,000
Retirement Cost	$0										
Total Project Cost	$3,100,000	$2,100,000	$5,100,000	$2,600,000	$5,600,000	$0	$0	$0	$0	$0	$18,500,000

Asset Class: Business Development **Business Case ID:**2367

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Business Development **Business Case ID:**2367

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Business Development **Business Case ID:**8550
Estimate Class: Class 5

Project Information

Name: NGT Rental Compressors - Ex Transit - (2021 to 2028)

Type: Enbridge Project **Start Year:** 2021

Asset Program: NGV

Project Type: Sales Station

Issue/Concern:

Fleet operators can achieve fuel cost savings and reduced emission benefits by operating their vehicles on natural gas versus diesel or gasoline. This presents an opportunity to grow EGD's NGV rental refueling business and promotes the use of natural gas to customers as an alternate source for fueling vehicles at a lower cost with lower emissions. By providing NGV fueling equipment to customers on a rental basis, EGD can achieve growth in the marketplace, while fully recovering costs.

Assets: There are a number of current NGV customers that EGD is successfully servicing, including:

- Truk-King 1.0- City of Toronto
- Bermondsey Yard - City of Toronto
- Ellesmere Yard – City of Toronto etc.

In addition, there are a number of confirmed new NGV customers that need to be serviced as well as a number of potential customers that EGD's marketing department have been working with. These customers are:

- City of Toronto - Ellesmere Yard (Upgrade) (confirmed for 2018)
- City of Toronto - Ingram Yard (New Installed) (confirmed for 2018)
- Truk-King 2.0 (confirmed for 2018)
- Park N Fly (potential for 2019-2020)
- UPS Kanata (potential for 2019-2020)
- TTC (potential for 2019-2020)
- Canadian Tire Corp (potential for 2019-2020)

-Mobile Fueling Station (potential for 2019 – 2020)

Related Program (if applicable): Once stations are installed and/or upgraded, they require maintenance to be performed. The associated BC for the maintenance work on existing stations is: BC#2369 & 9553.

Compliance: N

Solution Description:

This is the business case for NGT projects for the rental of CNG fuelling stations. This does not include Transit Buses since the cost for the latter is very significant and covered in BC #8553. This category is for rental stations for garbage truck, highway tractor and shunt truck fleets, etc.

Scope of Work: The scope includes the entire build and install of a new NGV station for confirmed customers. The scope includes the design, procurement, construction and commissioning of the NGV refueling stations assets, as follows:
Design: Outsourcing to an experienced consulting engineering company for the design of the transit fueling

stations
Procurement: The purchase of all of the NGV fueling equipment including:

- The electrical power and control system
- Gas dryer
- Gas compressor
- Above-ground piping and tubing
- Underground piping
- Storage cylinders
- Fuel control panels
- Dispensers
- Fill pressure control system.
- Trailers (Mobile Fueling only)

Construction & Commissioning: Construction of the NGV station including all civil, mechanical and electrical works

- Commissioning of the stations

Resources: Due to the scope and scale of the Project, EGD will be required to utilize the services of outside contractors for design, construction and maintenance. Engineering,drawing approval, and oversight will be undertaken by EGD.

Solution impact: By providing NGV fueling equipment to customers on a rental basis, EGD can achieve growth in the marketplace, while fully recovering costs.

Project Timing & Execution risks:

- City of Toronto - Ellesmere(upgrade) (2018 planning and execution)
- City of Toronto - Ingram Yard (2018 planning and execution)
- New Customers (from potential list) (2019-2022 planning and execution) Timing and go-ahead for project depends heavily on the commitment from potential customers. Currently there are three (3) potential customers in discussions with the marketing group for NGV servicing; however the number could potentially grow as new customers become interested.

Solution Options

OPTIONS				
OPTION NAME	SELECTED OPTION	RISK MITIGATED	TOTAL NET DIRECT CAPITAL	LRROI
Option 1	Y	4,141,379	$25,500,000	118

Asset Class: Business Development

Business Case ID:8550

Estimate Class: Class 5

Cost

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Direct Capital Cost	$4,500,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$0	$0	$25,500,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,500,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$0	$0	$25,500,000
Retirement Cost											
Total Project Cost	$4,500,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$0	$0	$25,500,000

Asset Class: Business Development **Business Case ID:**8550

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Business Development **Business Case ID:**8550

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

3.2 APPENDIX B: UNION RATE ZONES ASSET MANAGEMENT PLAN 2019 - 2028

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Asset Management Plan

2019-2028

uniongas
An Enbridge Company

November 2018

Contents

1 Executive Summary

1.1 Document Purpose

The primary purpose of this document is to outline the asset management plan for Union Gas Limited (Union) OEB-regulated assets for the years 2019 to 2028. This document also:

- Outlines the company's policy and strategies for achieving effective asset management.
- Demonstrates alignment with the company's Asset Management Program, which governs the approach to asset management at Union.
- Outlines and describes the inventory of assets within the various asset categories.
- Describes the 10-year prioritized expenditures in both capital investments and incremental operating expenses.

Definitions of key terms used throughout this document can be found in Appendix A.

Figure 1.1.1: Asset Management Purpose

1.2 Document Structure

The Asset Management Plan (AMP) is structured using the following framework. The AMP begins with a discussion of the background information that provides context for the forecasted capital and operating expenses over the 10-year period.

Figure 1.2.1: Structure of the Asset Management Plan

1.3 Advancing Asset Management

Over the past number of years, Union has identified the need to focus on asset management to achieve its goal of *Operational Excellence*. The ISO 5500X Standard for Asset Management has been applied to define the key guiding principles in the development of Union's Asset Management Program. The primary goal of asset management is to ensure that performance, cost and risk are balanced in delivering service to Union's customers, throughout the entire lifecycle of the asset. Continual improvements are regularly identified and acted upon to continue to drive effective asset management as identified in Section 3.5.

The Asset Management Plan is a key document that is used to outline the strategy and approach to asset management while summarizing the asset plans associated with all asset categories within the organization. The Asset Management Plan is filed as part of the Utility System Plan to support the company's rates application to the Ontario Energy Board (OEB) as per the OEB Filing Requirements For Natural Gas Rate Applications document (Section 2.2.6.1).

A number of key improvements to the Asset Management Program have been implemented and are further discussed in Section 3 of the plan.

1.4 Asset Management

The approach that Union has taken to implement asset management is illustrated in the following diagram from the Institute of Asset Management (IAM) document – *Asset Management an Anatomy*.

Figure 1.4.1: Asset Management – an anatomy, Version 3, page 16, Figure 3: The IAM's Conceptual Asset Management Model, theIAM.org

This diagram depicts the connections amongst many of the key elements and aspects of asset management, which without an overarching framework are otherwise disparate functions. By viewing all of these elements within a cohesive Asset Management Program structure, the company realizes significant gains from its efforts.

As outlined in the Section 1.1, the primary focus of this document is to outline the approach to asset management planning and the outcomes from this effort in the form of the capital and operating expenditures for the period from 2019 to 2028. This aspect of asset management falls into the *Strategy and Planning* subject group on the model for asset management depicted in Figure 1.4.1.

1.5 Portfolio Prioritization

The capital investment plan is prioritized for the 10-year period using a model that takes into account the following criteria to ensure that the best decisions are made to balance the competing priorities of cost, performance and risk:

- Customer engagement feedback/input.
- Company objectives.
- Risk.
- Workload and resource availability.

The prioritization model (further discussed in Section 4.2.1.1.4) uses the above criteria to develop a plan for capital expenditures to ensure that the optimal mix of projects is selected with the given constraints on capital funding.

1.6 About Union

Union is a major Canadian natural gas utility and has been providing natural gas services for more than 100 years. Union serves about 1.5 million residential, commercial and industrial customers in more than 400 communities in northern, southwestern and eastern Ontario. Union's franchise area is shown in Figure 1.6.1. Union also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec, and the United States (U.S.).

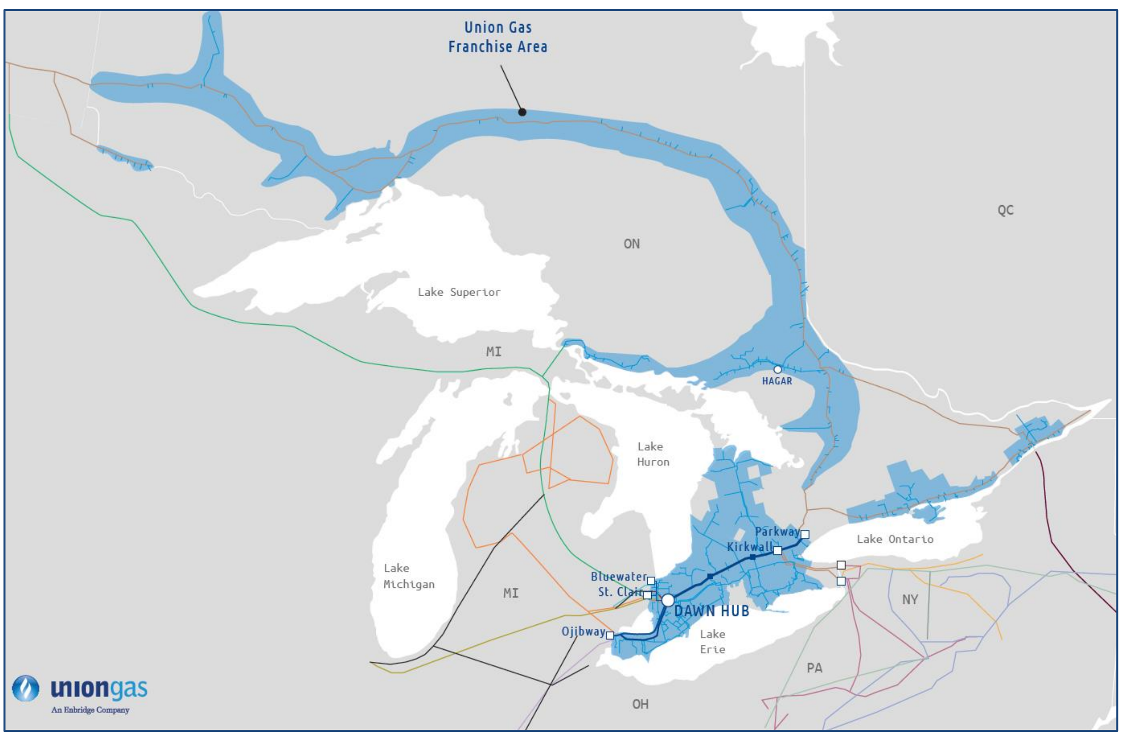


Figure 1.6.1: Union Franchise Area

1.6.1 Asset Base

Union has assets of approximately $8.9 billion and employs about 2,300 people. Union's natural gas assets include more than 70,000 kilometres of distribution, transmission, and storage pipelines, 2,980 system stations, about 1.4 million customer stations (including meters), 4,826 10^6m^3 (170.5 bcf or 188.1 PJ) of natural gas storage capacity, 760,000 horsepower of compression and one liquefied natural gas facility.

Union's supporting assets include service facilities, fleet vehicles and Technology and Information Services assets. The administration facilities include 74 buildings located across Ontario that support Union's functional business needs and activities, including an office located in Chatham that is the workplace for more than 680 people. Union's fleet includes about 800 trucks and 50 cars for the field workforce, plus trailers and equipment. The Technology and Information Services assets include 80 applications and technologies plus associated hardware that provide critical functionality to effectively run the business.

1.7 Asset Categories and Classes

Union has divided its assets into a number of different categories and classes (Figure 1.7.1) to align with unique design, operations and maintenance requirements.

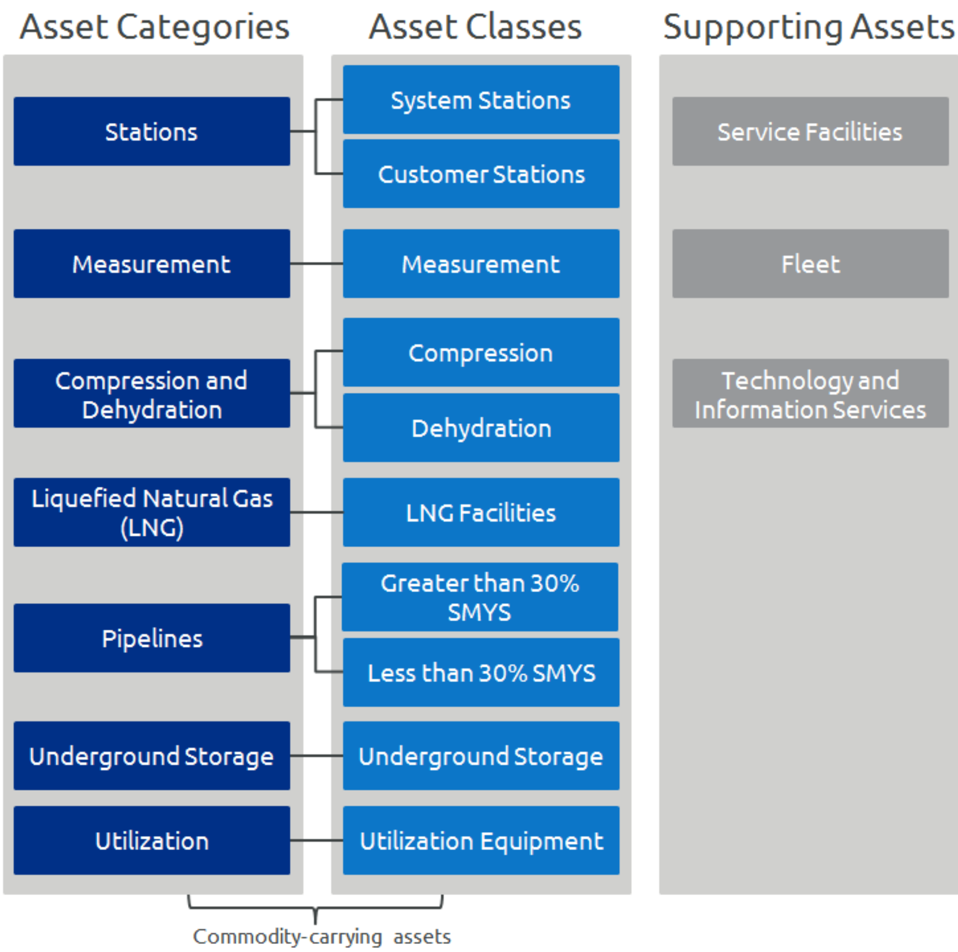


Figure 1.7.1: Asset Categories, Asset Classes and Supporting Assets

Each of the commodity-carrying asset categories is assigned an Asset Category Manager who is accountable for the overall performance of the category and the risks associated with the category.

1.8 Current Operating Environment

The discovery and production of shale deposits continue to impact the North American natural gas landscape. Prices are forecast to remain stable for the foreseeable future, as North American natural gas proven reserves are abundant and can meet the forecasted demand for the next 150 years.

Several new pipelines have been applied for, approved or have begun construction in the past year to move shale gas to liquid markets. The Rover Pipeline and Nexus Pipeline are both set to be online in 2018 delivering Appalachian shale to North American markets (including Union's Dawn Hub) to serve demand across the Great Lakes region, Eastern Canada, the Midwest United States (U.S.) and the Northeast U.S.

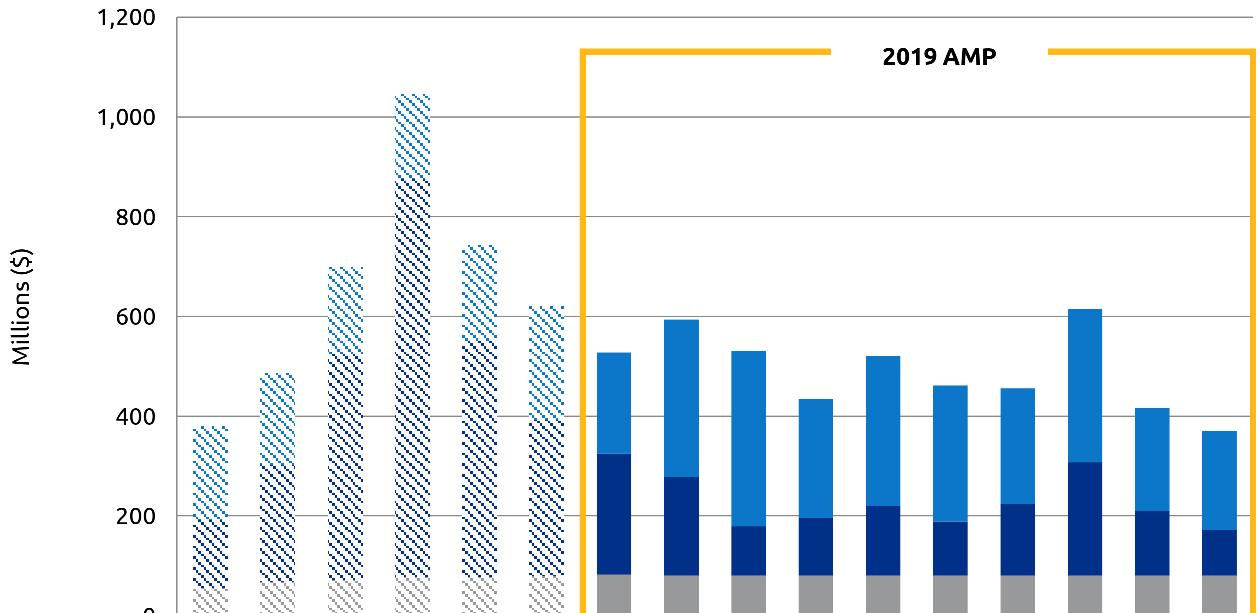
Communities served by natural gas use its availability and low cost as an important tool in their economic development. Many communities not served by natural gas are looking for service so that their constituents can enjoy the low-cost, clean-burning benefits of natural gas.

Natural gas is the cleanest burning conventional fuel producing almost no sulfur dioxide or particulate matter. Power generation by natural gas produces 45 per cent less carbon dioxide compared to power generation by coal. Natural gas produces up to 20 per cent fewer greenhouse gas (GHG) emissions than diesel or gasoline for transportation needs. It is also the ideal low-emission backup option when conditions are not optimal for solar and wind power generation.

Natural gas is also a safe energy choice. Stringent safety rules govern the production, transportation, storage and usage of natural gas. Pipelines provide a safe, reliable and efficient mode of transporting energy.

1.9 Capital and Operations & Maintenance (O&M) Forecast Summary

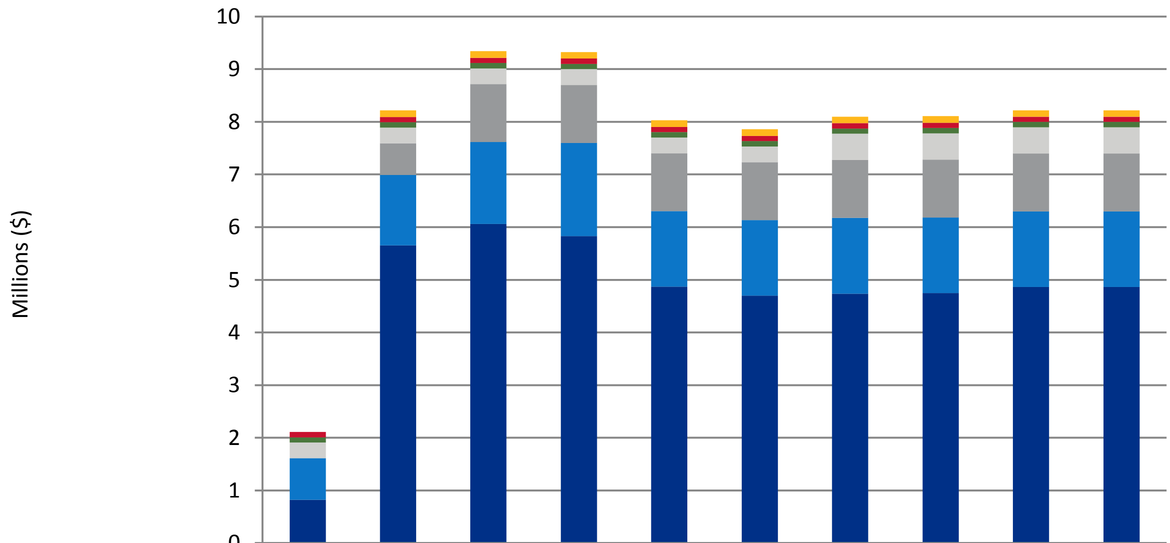
Figure 1.9.1 illustrates the forecast of capital required to meet growth needs and maintenance planning recommendations over the 10-year term of the Asset Management Plan. Some examples of major projects included in the maintenance plan include the Windsor Line Replacement (2020), London Lines Replacement (2021) and the replacement of the Dawn Compressor Plant C (2023-2024). Impacts can be seen in the growth plan from major projects including reinforcement of the Owen Sound System (2019), the Sarnia Industrial Line System (2020), and the Panhandle System (2026). These and other major projects are discussed in greater detail in Appendix D.



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Maintenance	188.2	183.7	173.5	168.3	191.2	229.3	202.5	315.4	351.0	238.3	300.1	272.7	232.1	307.0	206.1	199.0
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 1.9.1: Asset Capital 10-Year Forecast (all $ in millions)

Figure 1.9.2 illustrates the Operations and Maintenance (O&M) forecast incremental from 2018 based on maintenance plans. These changes include new facility greenhouse gas (GHG) abatement expenditures in support of new federal regulations, projects to support maintenance activities for major IT applications, increases to inspections of pipelines at water and bridge crossings, and an increased amount for inspections to support Integrity Programs.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CRES	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
IT	0.0	0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9

Figure 1.9.2: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2018)

2 Background and Objectives

2.1 Purpose and Objectives

Union is committed to using comprehensive asset planning to identify and prioritize expenditures over a long-term horizon; ensuring funds are appropriately allocated to maintain the delivery of natural gas safely and reliably to customers. This plan documents the effort and resources required to maintain and grow Union's Ontario Energy Board (OEB) regulated natural gas and supporting assets to meet customers' needs and preferences, to achieve a high degree of safety and reliability and to meet Union's goals, specifically to *deliver operational excellence*. This plan includes information about Union's asset planning processes and is a key input into short- and long-term financial planning. The primary purpose of this document is to outline the asset management plan for Union for the years 2019 to 2028. This document also:

- Outlines the company's commitment to and strategies for achieving effective asset management.
- Demonstrates the connection between the company's Asset Management Program, which governs the approach to asset management at Union, and its Asset Management Plan (AMP).
- Outlines and describes the inventory of assets within the various asset categories.
- Describes the 10-year prioritized expenditures in both capital investments and incremental operating expense.
- Demonstrates how Union strives to understand its customers' needs and preferences, and incorporate these into the long-term plan.

The AMP is a forecast of the growth and maintenance expenditures planned for Union Gas Limited (Union) assets. This plan demonstrates that Union will manage assets to serve its customers safely, reliably, and efficiently at the lowest cost.

2.2 Company Purpose, Vision, Goals and Values and Strategic Priorities

Asset management is a key component in achieving Union's Purpose, Vision, Goals and Values (Figure 2.2.1). Through asset planning and making informed, evidence-based decisions, this document specifically aligns with the goal to *deliver operational excellence.*

Figure 2.2.1: Union Purpose, Vision, Goals and Values

2.3 Organization and Structure

Union's parent company Enbridge Inc. carries out its activities through three core business units: Liquids Pipelines, Gas Transmission and Midstream, and Utilities and Power Operations (UPO) (Figure 2.3.1). The UPO business unit includes Enbridge Gas Distribution (EGD), Union Gas Limited (UGL), and other affiliate companies (Power Operations, Enbridge Gas New Brunswick Inc., Gazifère Inc., Niagara Gas Transmission Limited, 2193914 Canada Limited).

In addition, Enbridge's Corporate Services teams (Finance, Legal Services, Human Resources, Technology and Information Services, Supply Chain Management, Public Affairs and Communications, and Real Estate and Workplace Solutions) enable business units to achieve their strategic goals.

Within Ontario, Union is regulated by the OEB. This Asset Management Plan outlines the management of its OEB-regulated assets in Ontario.

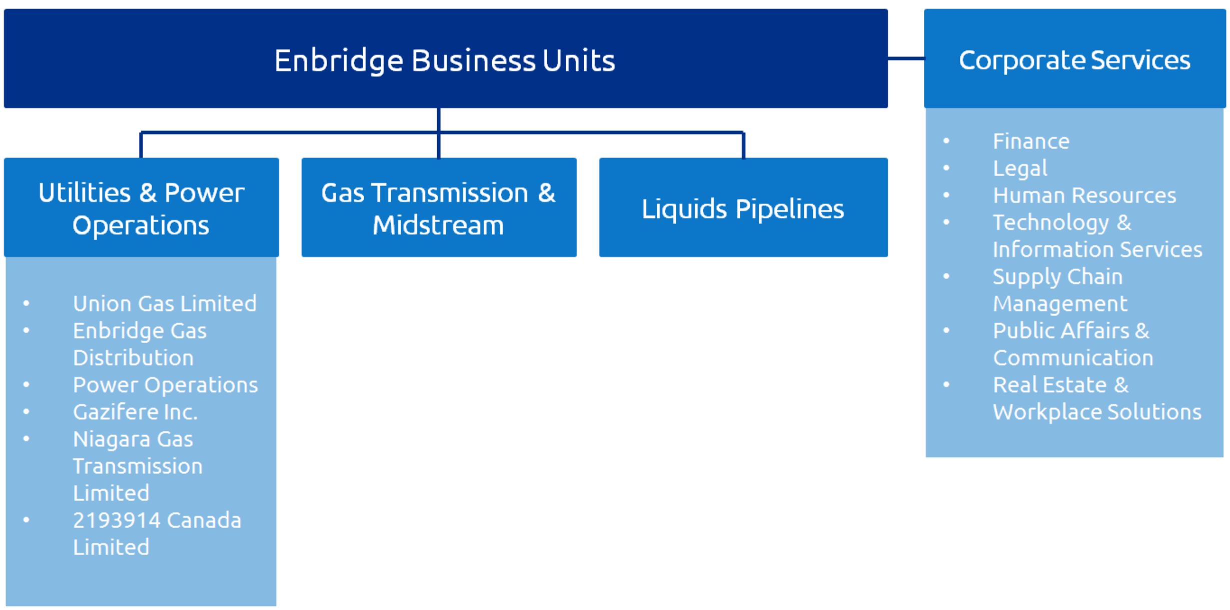


Figure 2.3.1: Enbridge Business Units

2.3.1 Union Gas Limited

Union is a major Canadian natural gas utility that provides energy delivery and related services to about 1.5 million residential, commercial, and industrial customers in more than 400 communities in northern, southwestern and eastern Ontario. Its distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southwestern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec, and the United States (U.S.). Union's storage and transmission system forms an important link in the movement of natural gas from Western Canadian and U.S.

supply basins to Central Canadian and Northeast U.S. markets. Union has assets of approximately $8.9 billion and about 2,300 employees.

Union's assets include small diameter pipe, meters, and regulators at homes the franchise areas, transmission pipe of up to nominal pipe size (NPS) 48, which is used to transport natural gas across Ontario; five main compressor plants including 20 storage compressors to move natural gas to and from storage reservoirs and along the transmission pipelines, and a liquefied natural gas plant used to support peak shaving in one area of the company.

Union's franchise area is divided into eight administrative areas, which divide the province both geographically and functionally. Union's Distribution Operations (DO) are divided geographically into the following seven districts:

- Windsor
- London
- Waterloo
- Hamilton
- Eastern
- Northeast
- Northwest

Figure 2.3.1.1: Union Distribution Operations geographic districts

The eighth area, Union's Storage and Transmission Operations (STO), consists of assets within various geographic areas throughout the province. The main operations centre for STO is the Dawn Hub, located in Dawn-Euphemia Township north of Chatham, Ontario.

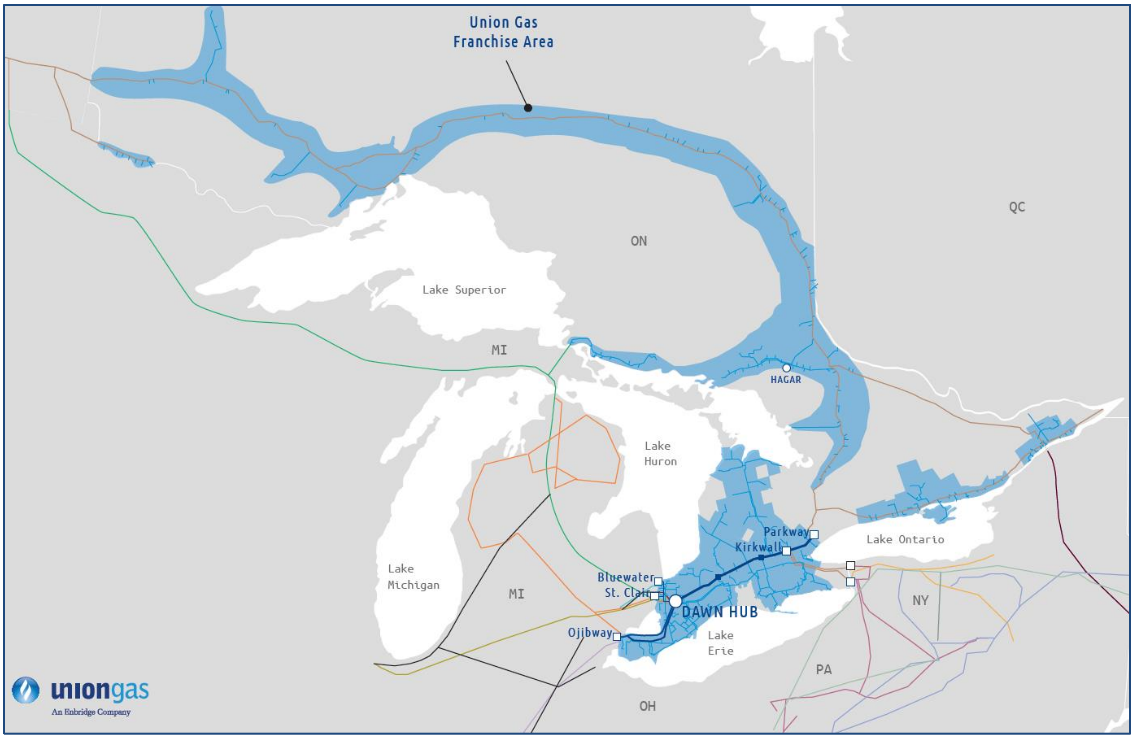


Figure 2.3.1.2: Union Franchise Area

2.4 Stakeholder Commitment

2.4.1 Customer Engagement

In 2017 Union engaged Innovative Research Group Inc. to assist in the design and implementation of an extensive customer consultation program in support of the development of Union's business planning. The objective of the consultation was to identify customer needs, identify and assess priorities among specific customer outcomes and explore customer preferences on some significant and illustrative choices before Union's planners of potential solutions, including the pace of investment.

This consultation complements Union's robust market research program that includes regular customer satisfaction surveys for all markets, as well as satisfaction tracking for all of the major transactions/touchpoints. Other customer engagement opportunities, such as focus groups and direct engagement from account representatives, are also undertaken on a regular basis to gather customer feedback on specific programs/services.

The key findings of the consultation include:

- Across all rate classes and all methodologies, customers consistently report high levels of satisfaction with Union.

- The top three most important outcomes for customers are price, safety and reliability. Minimizing environmental impact, customer service, making good use of rate monies and transparency are also important, but significantly less so.
- When asking customers to make business planning choices, there are times when they will choose system health, the environment or customer service over price.
- Customers want Union to spend what is needed to keep the system healthy in the long run even if it means higher prices.

Union has taken the customer preference for a steady pace of spend on assets into account within the 10-year maintenance capital outlook in Section 6. In addition, the project descriptions found in Appendix D provide more detail on how the results of the engagement consultation have been considered for specific projects/programs.

3 Asset Management Framework

3.1 Asset Management Program

The Asset Management Program is an additional program under Union's Integrated Management System (IMS). The program implements the systematic management processes and elements of the IMS to manage risk and assure compliance with internal and external requirements. The purpose of the Asset Management Program is to define the approach to asset management to ensure that that the company's assets are managed while balancing cost, performance and risk through the entire asset lifecycle.

Figure 3.1.1: Asset Management Purpose

The Asset Management Program document outlines the asset management framework and incorporates the Enbridge Management System Framework, Union's IMS requirements, and demonstrates alignment with the ISO 5500X Standard and IAM Subject Groups and Elements (Figure 3.1.2).

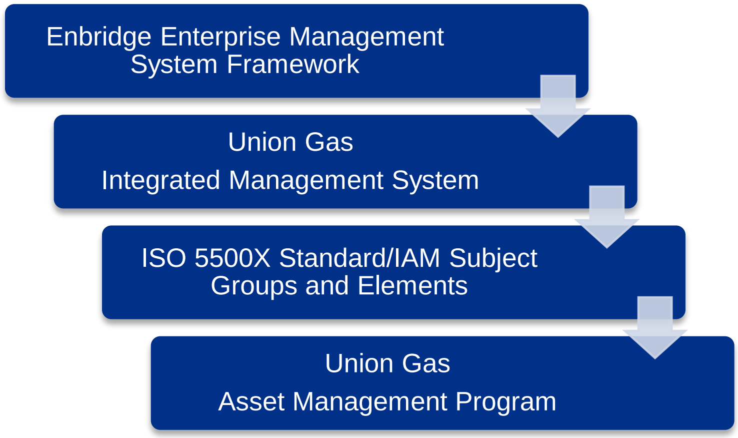


Figure 3.1.2: Alignment of standards and requirements

3.1.1 Scope of the Program

The Asset Management Program covers the full breadth of the asset portfolio that is managed by the operations groups within Union. This grouping of assets is often referred to as commodity-carrying assets, a term meant to distinguish them from assets which are operated and maintained by supporting groups such as Corporate Real Estate (CRES), Technical Information Services (TIS) and Fleet.

It is important to note that while the scope of the IMS is limited to commodity-carrying assets within the Distribution Operations (DO), Engineering, Construction and Storage Transmission Operations (ECS) functions, the scope of the AMP is expanded to encompass all OEB-regulated company assets (Figure 3.1.1.1).

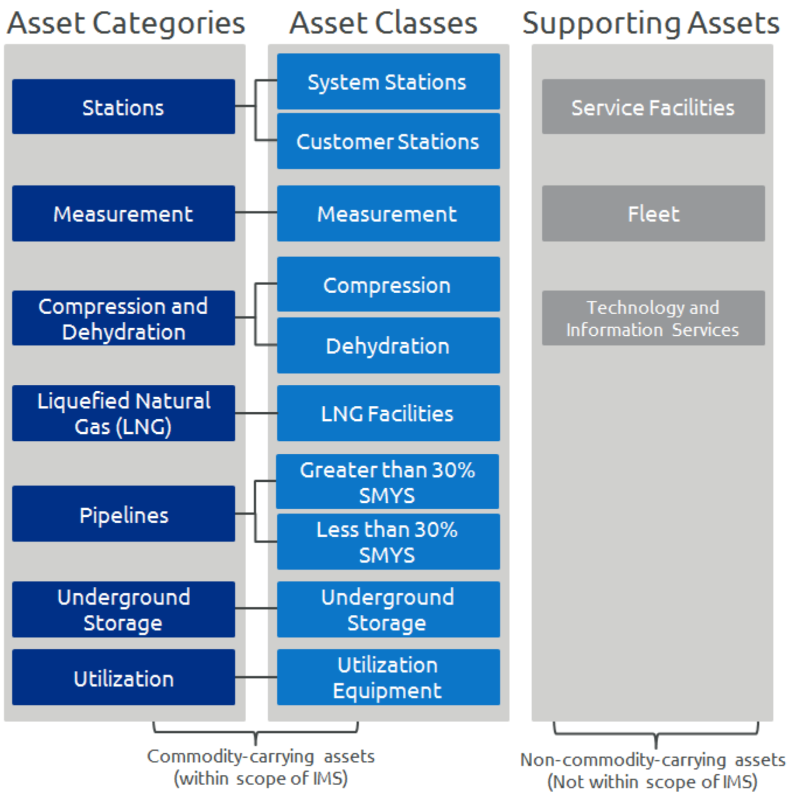


Figure 3.1.1.1: Scope of Assets for the IMS

The Asset Management Program encompasses all phases of the asset lifecycle (Figure 3.1.1.2), however, the business development and sales and marketing processes used to identify the need for new assets, or changes in performance requirements are not within the scope of this program. The need for new assets or changes in capacity is identified by the groups within the scope of this program using the inputs from the various business development and sales and marketing processes. New assets can also be identified by the groups within the scope of this program when the required asset performance can no longer be maintained with an acceptable balance of cost, performance and risk. The processes by which these asset renewal projects are identified are fully within the scope of the program.

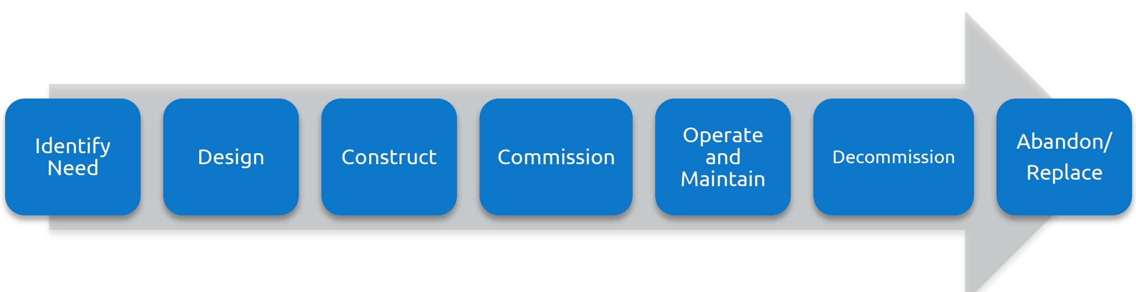


Figure 3.1.1.2: Asset Life Cycle Stages

3.2 Integrated Management System (IMS) Framework

Union implemented its first Operations Management System (OMS) in 2008, but introduced management elements and programs a full decade earlier. Since 2008, Union's IMS has evolved to include an increasing number of operational and personal safety and compliance programs, and has helped improve organizational performance.

In 2018, the OMS changed to the IMS to align with the Enbridge Safety and Reliability Policy. The IMS incorporates all dimensions of safety and reliability, including risk management and asset management. Union demonstrates its dedication to a zero-incident workplace through its commitment to managing risk and conducting business in a manner that protects the environment and the safety, health and security of its employees, contractors, customers and the public, and by driving continual improvement to deliver operational excellence. This commitment is outlined in a commitment statement (Figure 3.2.1) that is reviewed and signed by the Accountable Officer and communicated on an annual basis.

Union Gas
Integrated Management System (IMS) Commitment Statement

Commitment

Union Gas is committed to safe, reliable and compliant operations across the lifecycle of our assets. Leadership is dedicated to maintaining and continually improving our safety culture, our safety and reliability performance and our commitments to stakeholders. Union Gas' obligations include ensuring the safety and security of the public, employees and contractors, and protection of property and the environment.

To deliver on this commitment, Union Gas has established an Integrated Management System (IMS) that delivers compliance with the requirements of Enbridge's Enterprise Management System Structure, Safety & Reliability Policy, and Safety Principles.

Applicability

The Union Gas IMS applies to the lifecycle of Union Gas assets, including asset design, procurement, construction, operations, and abandonment and provides the governance structure for the organization's IMS framework and programs.

Figure 3.2.1: Union Gas IMS Commitment Statement

There are many benefits resulting from the implementation of the IMS, including:

- Structured, risk-based decision making.
- Clear roles, responsibilities and accountabilities.
- Compliance requirements are understood and met.

- Assurance that what needs to be managed is being managed.

Union's latest iteration of its management system in alignment with the Enbridge Enterprise Management System Framework and Standard was effective January 1, 2018. The current IMS Document includes 11 elements, and 9 operational and personal safety and compliance programs (Figure 3.2.2). Each of the management system programs incorporates the elements into their program design and each of the program leads is accountable for effective implementation.

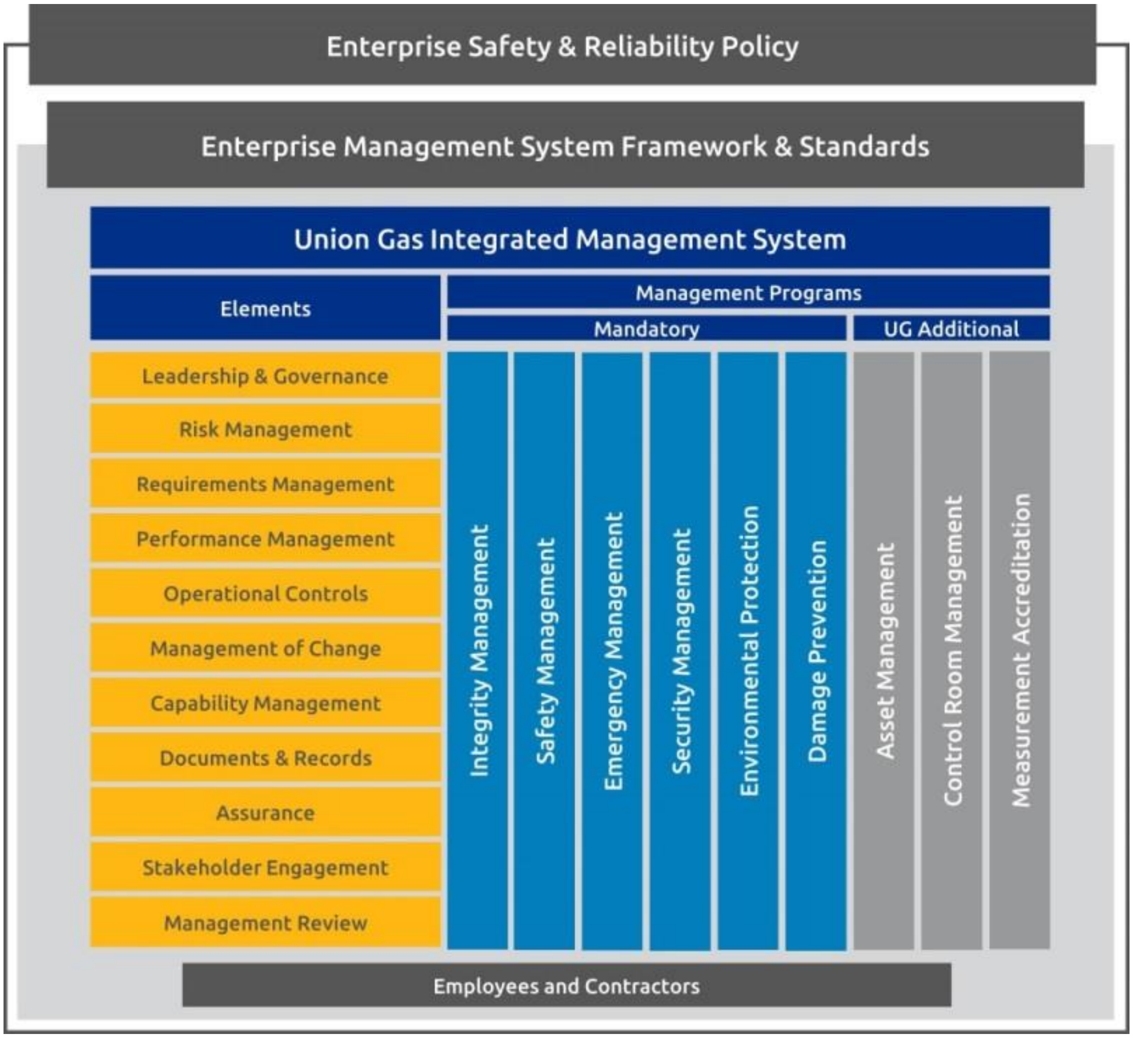


Figure 3.2.2: Union Integrated Management System (IMS)

Although the Asset Management Program is specific to asset management, there are aspects of asset management that are common throughout the other IMS programs. For example, the Integrity Management Program is focused on the Operations and Maintenance phase of specific asset categories.

3.2.1 The IMS and Continual Improvement

The IMS is predicated on the underlying principle of striving for continual improvement through the implementation of the Plan-Do-Check-Act quality cycle (Figure 3.2.1.1). Union's IMS Governance approach maintains the line of sight from front-line employees through to the executive leadership, and has been expanded to include the overall Enterprise level. Governance meetings occur on a quarterly basis and include a transparent and timely review of significant risks, compliance updates and performance metrics. The nine management programs and overall framework are each reviewed annually to ensure that goals, objectives and targets are being met effectively and to keep employees and the public safe. The IMS programs continue to evolve to include additional requirements such as personal and cyber security, abnormal operating conditions, public awareness, and to incorporate leading practices and consistent approaches across business units described in Figure 2.3.1 (Section 2.3). There are many IMS processes in place to drive continual improvement such as performance measurement, capability management, documentation review, formal incident reporting and investigation, and monitoring and tracking corrective actions.

Figure 3.2.1.1: Plan-Do-Check-Act quality cycle

Another way Union seeks to continually improve is through industry engagement. Key subject matter experts involved in the design and operations of assets are engaged in industry related code committees and industry best practice committees to better understand compliance requirements, to support the improvement of codes and standards that drive operational safety, and to learn and share best practices from industry peers. Examples include active membership of subcommittees for the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems, Canadian Gas Association (CGA) and American Gas Association (AGA) technical committees, participation in CGA and AGA surveys and workshops, and AGA peer reviews.

Union uses audits to ensure compliance with legal and regulatory requirements and improve on processes through corrective and preventive actions that are identified throughout. The audit strategy is reviewed through the IMS governance on a quarterly basis.

The following are examples of the internal audits that were conducted in 2017:

- Safety & Reliability (S&R) Verification of the Management of Change element identified four issues that have been resolved by updating reference documentation.
- S&R Verification of the Emergency Management Program identified one issue that has been resolved by updating program documentation.
- Systems audits performed on 30 contractors and material providers identified five non-conformances and 79 opportunities for improvement.
- Audit Services performed an audit of the Measurement Accreditation Program which identified three opportunities for improvement, which have been completed.
- The Field Quality Assurance Plan reviews details around assets and asset construction. In 2017 approximately 4800 reviews identified approximately 475 opportunities, all of which were responded to.
- The Safety Management Program and the Emergency Management Program were audited to the National Energy Board's Onshore Pipeline Regulations requirements with six identified improvements completed.

The following are examples of external audits that were conducted in 2017:

- The Integrity Management Program responded to eight recommendations from TSSA review.
- All emissions reporting was completed for 2017 with no issues.
- No issues were identified with the NEB Compliance Screening of the Safety Management Program.

3.3 Asset Management Roles and Governance

As part of the IMS framework, the Asset Management Program is subject to governance, oversight and coordination to meet the requirements as defined the IMS Document Section 1.4. Figure 3.3.1 represents the governance structure for the Asset Management Program under the IMS governance model.

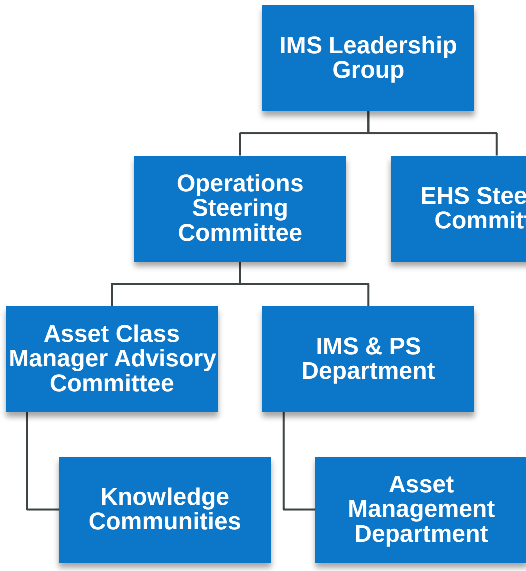


Figure 3.3.1: Asset Management Program Governance Structure

The Asset Class Manager Advisory Committee consists of Asset Class Managers who provide oversight and input into the Asset Management Program. This committee meets on a regular basis to build common understanding of asset management, share knowledge and guide decisions related to asset management. Two main functions are primarily responsible for the direction of the program as described in greater detail below:

1. Asset Category Managers and Asset Class Managers
2. Asset Management Functions

Asset Category Managers

Asset Category Managers are accountable to manage asset performance, support maintenance and operation, and are typically individuals at the director level with specific decision authority related to assets. This group does not have regular meetings, but is engaged to provide direction as required. The Asset Category Managers have overall accountability throughout the lifecycle of the assets within their category, including:

- Performance of the assets.
- Accountability for maintenance practices, including Standard Operating Practices (SOPs).

- Ensuring compliance to all applicable codes and regulations.

Asset Class Managers

Asset Class Managers are accountable to manage asset performance, support maintenance and operation and lead an asset knowledge community within their particular classes to identify risks and opportunities. The knowledge communities consist of subject matter experts (SMEs) in each asset category who support Asset Class Managers in risk assessments and the development of mitigations. These communities do not meet on a regular basis, but provide continuing support and knowledge to assist Asset Class Managers in delivering on their objectives. Asset Class Managers are individuals at the manager or supervisor level.

Asset Class Managers have accountability throughout the lifecycle of the assets within the class, including:

- Identification of required asset health information.
- Identification and definition of asset performance metrics.
- Definition and development of maintenance strategies, including SOPs.
- Addressing field-identified risks and issues related to the assets.
- Interpretation of codes and regulations as defined in the Operations and Environment Health and Safety (OEHS) Legal & Other Registry.
- Consultation with knowledge communities, as required.

Asset Category Managers and Asset Class Managers have additional assigned accountabilities related to asset management within existing roles in Operations and Engineering.

Asset Management Department

The Asset Management department is a group within the Integrated Management System and Program Support (IMS & PS) department that establishes asset management processes and provides support for reliability analysis and risk assessments.

The Manager Asset Management within this department provides leadership for the Asset Class Manager Advisory Committee and the application of, and alignment with, the ISO 5500X Standard for Asset Management. The Manager Asset Management has overall accountabilities for the Asset Management Program, including:

- Align with the IMS Commitment Statement and use systematic risk-based decision making.
- Develop program goals, objectives and targets to anticipate, prevent, manage and mitigate conditions that could adversely affect people, property, or the environment.
- Identify, assess, manage and mitigate risks to meet program goals, objectives and targets and to ensure compliance.
- Establish, implement and retain documented processes and procedures to meet the IMS Framework.

- Provide quarterly status reporting and an annual review of the program to identify continual improvement opportunities and corrective actions for endorsement by the IMS Governance.
- Develop and maintain the asset management framework, including the Asset Plan and Asset Class definitions.
- Facilitate the Asset Class Manager Advisory Committee.
- Provide resources to support Asset Class Managers, including:
  - Supporting asset health or metrics reporting.
  - Supporting the development of maintenance strategies, using techniques including Reliability Centred Maintenance (RCM) capabilities.
  - Analysis of asset data/information and support in closing gaps.

3.4 Review of Asset Management Practices

3.4.1 Target Operational Model (TOM) Process

In 2014 in conjunction with the implementation of the Enterprise Asset Management System (SAP PM), Union engaged a consultant to help develop a roadmap for the future of asset management at Union. The assessment involved a current state maturity analysis as well as determining the desired future state. The roadmap, entitled the Target Operating Model (TOM), specifies the various activities and initiatives required to achieve the desire future state.

The following graphic represents the various elements of asset management that formed the basis of the assessment. Representing asset management with this structure provides focus on the various elements that are most closely aligned with the strategic objectives.

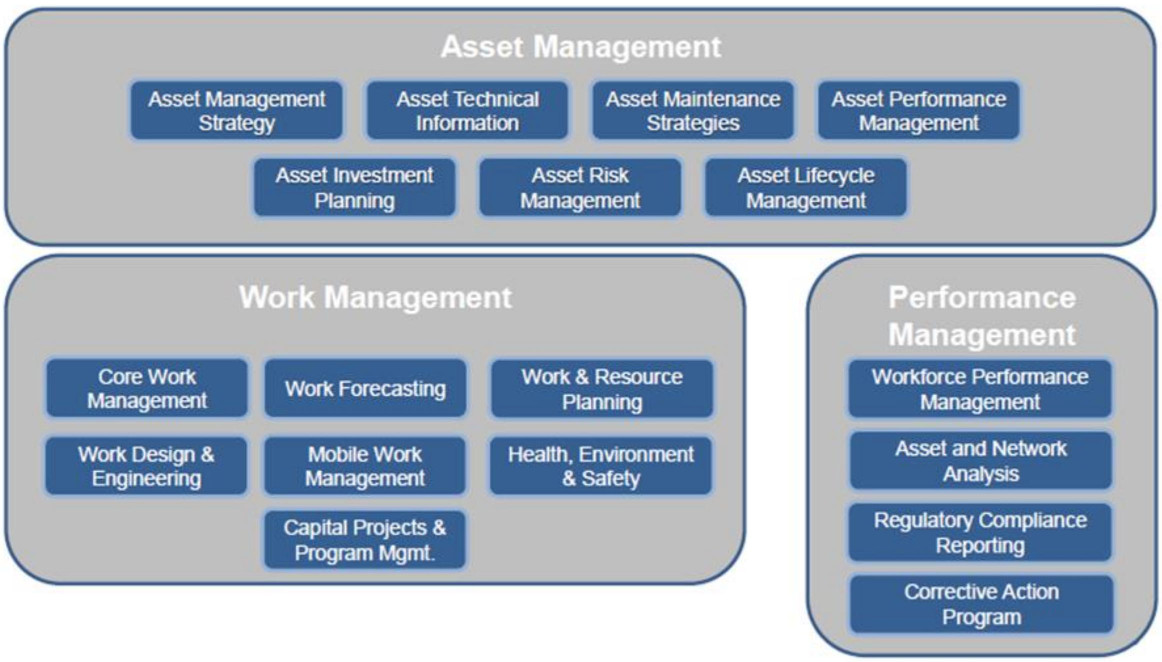


Figure 3.4.1.1: Enterprise Asset Management System structure

3.5 Continual Improvement

A key outcome from the TOM discussed in Section 3.4.1, was a series of improvement opportunities to be undertaken to achieve the longer-term vision for asset management. A detailed review and update to the TOM was undertaken in 2017 to ensure that Union continues to focus on the desired future state. Many of the asset management improvements have been realised through the completion of activities identified in the TOM.

Several of the key improvements achieved to date include:

- Integrated the Asset Management Policy with the IMS Commitment Statement and Framework.
- Established the asset planning process.
- Identified asset categories and governance.
- Introduced the treatment of maintenance as a business. This initiative centred on better maintenance planning and scheduling with the introduction of a function for maintenance planning within the Storage and Transmission Operations (STO) group.
- Implemented SAP PM as the Enterprise Asset Management (EAM) System (2015). This integrated system facilitates the gathering of data from maintenance processes, and provides the ability for greater understanding of costs, and materials requirements.
- Implemented a Technical Records and Information Management system.
- Introduced Hazard and Operability Studies (HAZOPs) and Reliability Centered Maintenance (RCM) for key assets.
- Developed Capital Project Operational Readiness processes.
- Standardized compressor station and customer station design.
- Implemented a mobile work management application and hardware platform for all operations employees.
- Implemented Legal Register process and governance.
- Developed a strong incident reporting and learning program.
- Developed a comprehensive Audit Strategy.

Although many significant improvements have been made over the past few years, Union continues to build on its successes by being driven by a strong culture of continual improvement. The TOM will remain an important roadmap to maintain focus on achievement of its vision.

4 Strategy and Planning

4.1 Asset Management Strategy

The Asset Management Program has been developed in alignment with the ISO 5500X Standard for Asset Management and the Institute of Asset Management's (IAM) Asset Management - an anatomy Version 3 document which provides a practical framework for an Asset Management System based on the ISO 5500X requirements. The approach to asset management at Union is to align with the ISO 5500X Standard for Asset Management, but not to certify to that standard.

Figure 4.1.1: Asset Management – an anatomy, Version 3, page 16, Figure 3: The IAM's Conceptual Asset Management Model, theIAM.org

Asset Management - an anatomy Version 3 interprets the ISO 5500X Standard and provides a practical way to implement its requirements by breaking them down into 39 subjects grouped into six subject groups in alignment with the six major components of asset management:

1. Strategy and Planning.
2. Asset Management Decision-making.
3. Life-cycle Delivery.

4. Asset Information.
5. Organization and People.
6. Risk and Review.

The IAM model for Asset Management shown in Figure 4.1.1 has been used to build and implement an effective asset management framework at Union to balance cost, performance and risk through the entire asset lifecycle. By adopting the IAM model, Union can ensure alignment with the ISO 5500X Standard and demonstrate connections between the subjects of asset management and the elements of the IMS. This model also provides a simple visual representation of the complex discipline of asset management, showing the connections between the various elements and functions across the organization.

According to the IAM Model for Asset Management depicted in Figure 4.1.1, the subject of asset management planning falls under the subject group of *Strategy and Planning* (refer to Figure 2). It further defines asset management planning as the detailed activities, resources, responsibilities, timescales and risks for the achievement of the asset management objectives. This guidance has been used to develop the content and strategy of the AMP.

4.1.1 Asset Management Strategies and Objectives

4.1.1.1 Enbridge Enterprise Strategic Priorities

Union's asset management strategic framework includes the Enbridge Enterprise Strategic Priorities, Union's Purpose, Vision, Goals and Values and the Engineering, Construction and Storage Transmission Operations (ECS) and Distribution Operations (DO) Lines of Sight. These inputs help to determine and guide the asset management strategies and objectives.

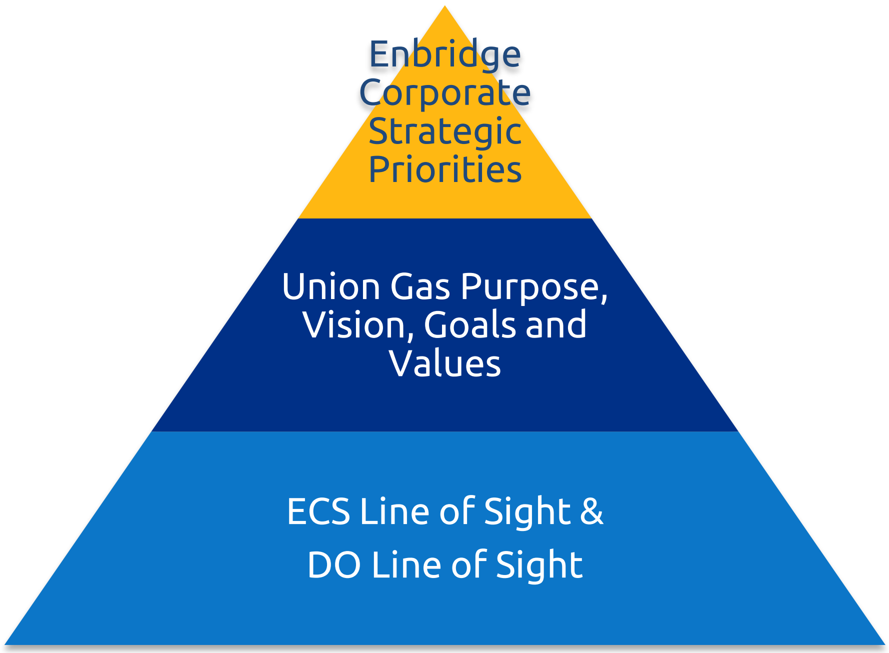


Figure 4.1.1.1.1: Hierarchy of inputs

The Enbridge Enterprise Strategic Priorities are defined to enable the enterprise to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities and contribute to Enbridge's success. They support the company's purpose of fueling people's quality of life, while maintaining the foundation of the business, and positioning the company for the future. This document directly supports and aligns with the priorities for *Safety and Operational Reliability*, *Execution of Capital Program*, *Position for Long-term Growth*, and *Stronger Financial Position*.

Asset management is a key component in achieving Union's Purpose, Vision, Goals and Values (Figure 4.1.1.1.2). Through asset planning and making informed, evidence-based decisions, this document specifically aligns with the goal to *Deliver operational excellence.*

Figure 4.1.1.1.2: Union Purpose, Vision, Goals and Values

4.1.1.2 Asset Management Goals

The goal of asset management at Union is to ensure that evidence-based decisions are made to balance performance, cost and risk in alignment with the ISO 5500X Standard for Asset Management. The following objectives support this goal and are in alignment with the purpose of Union' Integrated Management System (IMS).

Safety

- Enhance risk management processes with a focus on effective risk management and ensuring adequate layers of control.
- Facilitate identification of hazards at all levels and actively manage the operational risk registry.

Reliability and Integrity

- Implement Maintenance Optimization across Union operations, beginning with the most critical assets.
- Identify critical assets and ensure the correct data is collected and maintained in the correct system, with the right level of accuracy.
- Update Integrity Management Program documentation and associated Long-term Integrity Plans, leveraging risk management to address pipeline condition.

Compliance

- Complete the development and implementation of a comprehensive Technical Records program, compliant to legal, regulatory, and operational requirements.

Effective Asset Management

- Develop a comprehensive Asset Plan identifying the maintenance and growth requirements of gas carrying assets, taking into account asset health, and customer and shareholder requirements.
- Fully leverage the Geographic Information System (GIS) to support all Union business strategies that contain a Geospatial component, with a focus on data integrity, end user experience, and mobility.
- Enrich the understanding of assets through improved asset information governance to support asset maintenance tracking and analysis, with a focus on critical assets.

4.2 Asset Planning

4.2.1 Overview

The Asset Management Plan (AMP) includes information about the addition of assets to meet customer needs and maintenance requirements to ensure ongoing safety and security of supply for Union customers. Processes govern various phases of the asset lifecycle. The identification of the need for a capital expenditure can either be to satisfy a growth requirement or to resolve degraded condition or performance of an existing asset. In either case, the process to create a new asset is the same.

Growth includes adding assets to reinforce existing systems and to provide service to new customers. Growth is driven by increased in-franchise and ex-franchise demand as well as changes in the supply dynamics of natural gas. The process of determining maintenance requirements, referred to as Maintenance Planning in this Asset Management Plan, is completed for each asset based on asset health and compliance needs with a focus on delivering services reliably at the lowest lifecycle cost.

The asset planning process begins with the identification of need. The need for a new asset is typically driven by one of two primary causes:

- New demand on the system that cannot be satisfied by the existing asset base (growth); or,
- Asset performance degradation requiring asset renewal (maintenance).

In either case, the planning of the new asset is done in such a manner to allow the Company to continue to meet its strategic objectives. The following Section outlines the unique strategy and planning approaches associated with the two main categories of investments: growth and maintenance.

4.2.1.1 Identify Need

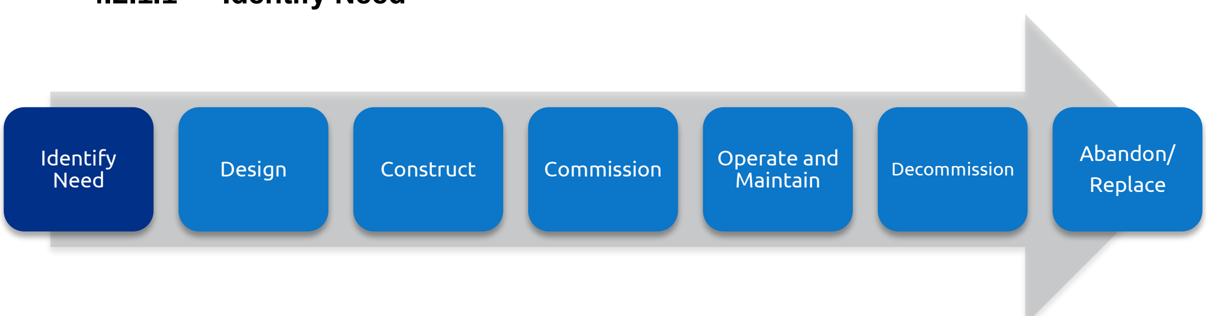


Figure 4.2.1.1.1: Asset Lifecycle Model

Projects are identified in a number of different ways. Union's risk management processes involve a number of formal steps to identify, mitigate, and monitor risks. Section 4.2.1.1.3 of this plan provides a detailed outline of Union's risk management process. Mitigation for the risks identified through this process is often projects to improve reliability or safety. Projects may also be identified or required as a result of regulation or code changes and when municipal projects result in conflicts with Union's infrastructure requiring relocations.

All potential projects are reviewed, evaluated, tracked, and monitored over time to determine if the risk level associated with a given item is increasing or stable. These potential projects, with a variety of priority levels, are used as a starting point for the annual budget cycle.

4.2.1.1.1 **Growth Planning**

Projects to accommodate new customers, to maintain adequate flow and pressure for all Union customers, and to meet storage and transportation needs of customers are planned by the Distribution Planning, System Planning, and Storage Planning groups. These projects include the installation of new mains, reinforcement of existing mains, as well as installation of new stations, and upgrades to existing stations as a result of in-franchise or ex-franchise growth. In-franchise growth at Union is defined as increased natural gas peak demand in the franchise areas of Union. Ex-franchise growth is the increased storage and transportation needs of customers primarily outside the franchise who provide or require natural gas services in Ontario, Quebec, and major U.S. natural gas consuming areas like the U.S. Northeast.

The Distribution Planning group makes asset planning recommendations for distribution systems, which are the pipeline and stations systems in regions throughout Union and include some of the transmission systems that supply these regions.

The System Planning group make asset planning recommendations for the three major transmission systems which include the Dawn to Parkway System, the Panhandle System and the Sarnia Industrial Line System.

The Storage Planning group makes asset planning recommendations for all underground storage facilities as well as for the Dawn Compressor Station.

Asset Growth – In-Franchise

In-franchise growth is driven by changes in the peak demand for new and existing general service and contract rate customers. The primary driver for this growth is the value proposition natural gas provides to Union's residential, commercial, agricultural, and industrial customers when evaluating their energy needs.

Union records indicate that in the general service, the total annual average use per customer has been declining since the early 1990s. This trend is expected to continue due to energy efficiency related activities, technology advancements, Demand Side Management (DSM) programs, and the potential impact of carbon policy initiatives.

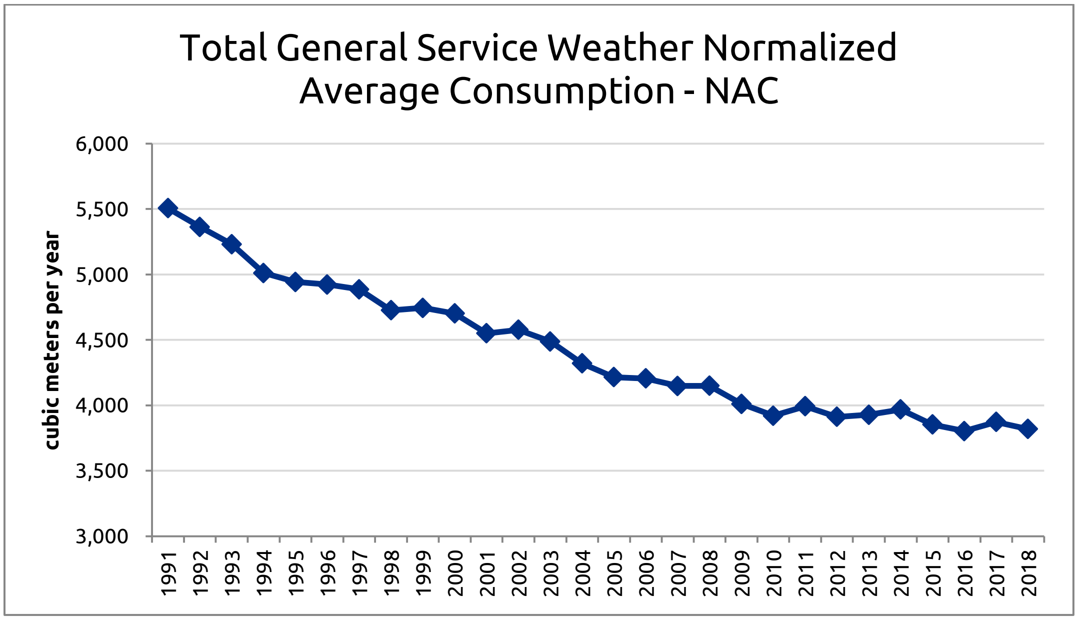


Figure 4.2.1.1.1.1: Normalized Average Consumption

While annual average use per customer is decreasing over time, the design day demand, which is the total average daily demand and peak hourly demand at the design weather condition, is increasing over time. The design day is the coldest potential winter day in Union's franchise.

General service growth is comprised of three areas which include new residential housing, commercial and small industrial businesses, and customers in these categories converting to natural gas. Customer growth in the general service market typically mimics the population growth of the franchise, however, area specific growth plans are used to ensure localized knowledge is considered when optimizing the gas delivery network.

Growth in the contract rate markets tends to be driven by a combination of population growth in the franchise as well as broad economic drivers. Typically, growth within the institutional markets is driven by community growth that spurs the need for new and expanding social services such as hospitals and universities. Natural gas demand is also increasing in these segments with the adoption of combined heat and power applications as a way to economize on their electricity costs.

The industrial contract rate market growth is driven by economic and investment factors such as exchange rates, tax rates, alternate fuel costs, cost of electricity, and proximity to markets.

The greenhouse contract rate market continues to grow at a faster than historic pace. Natural gas is the fuel of choice for these enterprises and growth in the greenhouse market continues to be strong with no signs of slowing down.

Future growth in the industrial rate contract market may come from chemical, mining, and steel segments. Currently significant uncertainty exists in some markets due to tariff and trade issues. Any future contract rate projects are subject to the economic tests identified in case EB-2017-0188.

Conversely, the power generation contract market has seen a decline in recent years as evidenced from customers opting to not renew their gas distribution contracts. This has been partially offset by TransCanada Energy's Napanee plant which is slated to be in commercial operations in Q4 2018. As the province's nuclear refurbishment plan is executed, additional generation may be required as various nuclear plants are taken out of service for major maintenance. However, according to the 2017 Independent Electricity System Operator (IESO) Long Term Energy Plan, incremental generation is not expected to be required until the mid-2020s. In addition, at this time it is not certain that this need would be met with natural gas fired generation since the Independent Electricity System Operator has indicated they are agnostic with respect to generation fuel type.

Growth in design day consumption has been modest in Union's franchise area. Increases in general service demand follow the population growth. A forecast of annual consumption and the number of customers can be found in Table 4.2.1.1.1 below. These projected growth figures, plus a forecast of contract growth based on historical contract growth, were used to create the forecasts in this plan.

Table 4.2.1.1.1.1: Forecast of Consumption and Customers

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Consumption (10^6m^3)	12,919	12,981	13,582	13,873	13,817	13,859	13,710	13,687	13,564	13,490
Customers (in 1,000's)	1,501	1,518	1,535	1,552	1,568	1,585	1,601	1,616	1,632	1,647

Asset Growth – Ex-Franchise

Growth in the ex-franchise storage and transmission business is driven by economic factors such as exchange rates, interest rates and gross domestic product, but the primary driver relates to changing North American natural gas market fundamentals such as demand and supply, natural gas prices, natural gas basis differentials (price differential between location), and North American-wide infrastructure projects.

The major contributing factor to Union's recent infrastructure expansion relates to the growth in natural gas production from the Marcellus and Utica shale basins which are within 300 km of Ontario and shippers that are accessing the Dawn Hub. As a result, the flow of natural gas on the Canadian and U.S. pipeline grid is changing and continuing to evolve.

Although difficult to forecast, going forward Union expects further growth along the Dawn Parkway System driven by further demand growth in the U.S. Northeast and Ontario Local Distribution Companies (LDCs), as well as natural gas fired generation due to Ontario's nuclear refurbishment plan, when executed.

Distribution Growth

Union's Distribution Planning group is accountable for making asset planning recommendations with regard to the sizing of mains, services, and station capacities in the Union franchise distribution systems. The distribution systems are designed to ensure the appropriate infrastructure is in place to supply natural gas to customers within the many towns and cities across the franchise. This is accomplished through the use of hydraulic modelling techniques.

Distribution Planning designs systems to meet peak hourly consumption to ensure there are no outages on the design day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although annual consumption has been decreasing year over year, Union has not seen a decrease in peak hourly consumption.

The Facilities Business Plan (FBP) is an internal planning process used by Union for the identification of reinforcement facilities required to support forecasted growth over a specific geographic area. The FBP is developed for a geographic study area which provides an overall business case for the long range system expansion for the area. Union's franchise area has been divided into a number of specific FBP study areas based on operational areas, pipeline system configuration, and geographical features. FBPs provide a complete analysis of the study area based on a 10-year customer forecast, called the FBP forecast. Based on the FBP forecast, future facilities, both new and reinforcement, can be identified, economically evaluated, optimized, and scheduled to meet the future growth demands on the system.

The advantages of this FBP long range planning approach can be summarized as follows:

- Through the identification of future growth areas, Union can be more responsive to customer needs.
- Optimum, least-cost facilities can be identified to service the growth.
- Long-term security of supply to the overall system can be achieved.

The timing of the facilities is based on current customer attachments and demand forecasts which determine the need for additional facilities. Union updates each FBP as required to monitor the development of the system and to determine if the plan should be modified in any way. With Distribution System reinforcement, the timing of the proposed projects is based on the best available growth forecast information. When the proposed reinforcement plan results in significant peaks and valleys in the capital profile, opportunities are sought to attempt to pace the spend by either deferring projects or bringing them forward into earlier years.

It is Union's objective to provide adequate capacity to serve both current customers and new customers being added to the system. The system will be continuously monitored to better determine when and what reinforcement will be needed to keep the system above the required minimum pressure to serve Union's customers. Figure 4.2.1.1.1.2 shows an example of an FBP map depicting areas of growth within an FBP study area.

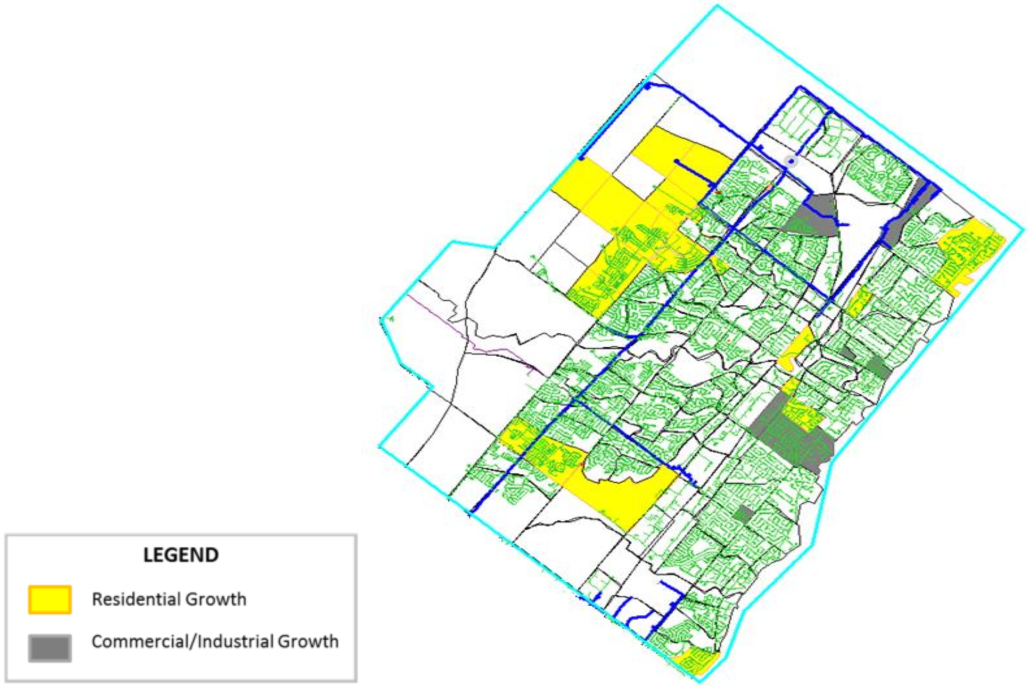


Figure 4.2.1.1.1.2: Example of an FBP Map Showing Residential and Commercial/Industrial Growth

System Growth

Union's System Planning group is accountable to make asset planning recommendations for the three major transmission systems: The Dawn to Parkway System, the Panhandle System, and the Sarnia Industrial Line System. These systems move natural gas from receipt points to delivery locations along the pipeline to meet the volumetric demands and pressure requirements of Union's in-franchise and ex-franchise customers. The pipeline system forms the foundation for future development as customers' needs grow, and represents the supply into the Union South Distribution Planning models as detailed in Section 5.2.1.

System Planning designs systems to meet peak daily consumption to ensure there are no outages on the design day. Metered data is gathered and analyzed each year to calculate demand assumptions used for system design. Although annual consumption has been decreasing year over year, Union has not seen a decrease in peak daily consumption.

Demand for additional long term capacity on Union's major transmission systems is typically met through installation of new pipeline, station, and/or compression. Non-facility options are also considered using gas supply on third party contracts for peaking service to optimize the resources used to provide service. Consideration of options will include evaluating the effect on system reliability, service quality, security of supply, and rates for service. Options are considered based on the "lowest cost per throughput" or highest economic benefit.

The Asset Management Plan provides a magnitude level estimate of future pipeline or compression facilities and does not include any non-facility alternatives or detailed economics for alternative comparisons. In the event that the projects identified in the asset plan proceed, Union will complete a Leave to Construct application where a detailed and rigorous examination of both the facility and non-facility alternatives, including detailed costs and economics will be completed when required.

Storage Growth

Union's Storage Planning group is accountable to make asset planning recommendations for all Underground Storage facilities, as well as the Dawn Compressor Station. The modelled deliverability required from Dawn is a direct output from the System Planning models previously defined and the Union system supply arriving at Dawn from the Gas Supply Plan.

The natural gas storage assets are expanded through either improving existing storage pools or developing new storage pools. Improvements are generally made by increasing the maximum operating pressure of the pool. New storage pools are typically developed by converting a depleted natural gas production field. An Ontario Energy Board (OEB) application and approval is required for developing or improving a storage pool.

In case EB-2015-0551 the OEB determined that Union is required to reserve 100 PJ of storage space to serve the needs of its in-franchise customers. On an annual basis the in-franchise storage space requirements are determined through a natural gas supply plan, using the aggregate excess methodology. The current 10-year forecast indicates that the in-franchise customer requirements are less than the 100 PJs of reserved storage space. This is primarily due to Demand Side Management (DSM) which has reduced the annual consumption of natural gas. Additional requirement for storage space for ex-franchise customers is determined by market demand, market prices, and the availability of economic projects.

Any deliverability shortfalls on Design Day indicate additional storage assets are required. Adding storage wells, compression and piping are typical methods to improve deliverability. Storage deliverability projects also require OEB approval for construction.

No storage growth is forecasted at this time.

Growth – Other

A new area of growth for Union is Compressed Natural Gas (CNG), Liquefied Natural Gas for vehicles (LNG), and renewable natural gas (RNG). Projects forecast in these areas will support low carbon fueling and production for Canada's Clean Fuel Standard.

4.2.1.1.2 **Maintenance Planning**

Maintenance Planning at Union is the planning of maintenance capital and operating and maintenance expenditures to ensure the safe, reliable, and compliant delivery of services over the life of the assets. Work that will result in maintaining and extending the life of an asset, typically identified as maintenance, is included in the asset maintenance plan. This includes capital and Operation and Maintenance (O&M) expenditures for projects ranging in complexity and scope, as well as a number of spend requirements to maintain tools and other support equipment.

Due to the complexity and variety of Union's assets, they are broken down into asset classes as further explained in Section 3. Asset health requirements and maintenance plans are developed for each of Union's asset classes. Union has a number of programs in place to ensure continued reliability of each asset, including, but not limited to: the Integrity Management Programs, Damage Prevention Program, defined maintenance plans, and robust operational monitoring of Union's critical stations.

The asset lifecycle planning process ensures that optimal decisions related to maintenance expenditures are made through proper prioritization of all identified issues and projects. The creation of a 10-year AMP ensures that issues are identified early allowing for proper risk assessment, project planning, and execution.

Maintenance is determined based on the unique requirements of the asset class to ensure optimal maintenance is being performed and compliance requirements are met. Basic maintenance strategies generally fall into several common categories ranging from run-to-failure to condition-based maintenance.

All assets pass through a number of phases throughout their lifecycle as depicted in Figure 4.2.1.1.1 Asset Lifecycle Model. The primary focus of this Section is to outline how projects to renew or replace assets are identified, selected for execution, and approved. The creation of the 10-year AMP is an important tool to ensure that capital resources are allocated to the highest priority items to reduce risk through improving reliability and safety.

Asset Condition or Health

Asset condition is monitored and impacts the need for a project to either replace an asset or to restore its performance to the required level. As asset condition and performance degrade, risks are raised through the risk management process. There are a number of factors that affect asset health and these generally apply to all asset categories.

The following are examples of some of these factors:

- **Third Party Damage** - When third parties perform work near Union's facilities, there is a risk that they may damage them, referred to as third party damage. Union has a number of strategies to mitigate this risk. All incidents of third party damage are tracked and assessed to determine improvement solutions. Mitigations include Union being a founding and contributing member of Ontario One Call, being a lead proponent to the Ontario Underground Information Notification Systems Act, and actively participating on the Ontario Regional Common Ground Alliance. Other mitigations for higher pressure pipelines include:

- Providing personnel to observe when others are working near Union's facilities (third party observation).
- Installing markers or signs along the pipeline which provide information about the presence of the high pressure pipeline.
- Establishing easements over certain pipeline and then monitoring (ground and aerial surveys) and maintaining these easements to keep them clear of excess vegetation and of third party structures.

- **Construction/Installation Practices** - Union has developed and maintains manuals and specifications which outline proper installation and maintenance methods and stringent quality control to ensure these requirements are met. All pipeline systems are designed by Professional Engineers and use Union approved materials which meet or exceed Code requirements. Union has high quality and safety standards that construction contractors must meet. Maintenance and major construction projects performed by contractors have an assigned inspector to ensure the quality of the installation, that it is constructed as per the design, and that proper construction procedures are followed.
- **Corrosion** – In addition to pipeline coatings, anodes and rectifiers are used to provide cathodic protection and reduce the chance of corrosion of pipelines. The level of cathodic protection is regularly checked to ensure adequate levels of protection. Pipelines that are identified to have inadequate cathodic protection will be assessed to determine the root cause of the inadequate protection and a solution will be implemented. Pipeline corrosion is also measured and assessed by either inline inspection runs or External Corrosion Direct Assessments and digs for pipelines greater than 30 per cent SMYS.
- **Age** - While age can be a factor in determining asset health or condition, on its own it is generally insufficient to make decisions related to replacement projects. There are some key areas in which age is used to drive maintenance requirements, primarily with respect to large rotating equipment such as gas turbines, power turbines and compressors. The Original Equipment Manufacturers (OEM) prescribe maintenance intervals that are based on machine run hours. Although the age of the asset may not have a direct impact on its condition, there comes a point where obsolescence becomes the primary risk. Whether it is an IT application or an aging compressor, as the asset ages beyond a certain point, vendor support for it declines to a point that the risk becomes intolerable.
- **Operating Conditions** - Operating conditions such as the flow profile of a station, magnitude of pressure differential, and equipment settings, can all impact the health of station assets. Equipment that is stressed due to “on/off” type operation or consistently operating at its maximum capacity can accelerate the degradation in performance of the asset and the frequency of maintenance interventions and/or failures. Natural gas quality can also have an impact on the health of the asset.

Debris, pipeline corrosion, and pipeline contaminants including moisture can cause damage to the equipment.

- **Operating Practices** - The conditions under which the equipment is operated is a significant determinant of asset health. Operating procedures, training and ongoing monitoring of key operational parameters are all used as a means to ensure the longevity of the equipment by ensuring that the asset is operated in a manner that is consistent with its capabilities and design.

- **Maintenance Program Effectiveness** - An effective maintenance program ensures that the essential care items such as lubrication, alignment, and filtration are completed as required to ensure the asset continues to perform its required performance. An effective inspection program will ensure that asset performance degradation is identified early to allow for proper planning and scheduling of not only maintenance interventions but also longer-term capital replacements.

- **Environmental Elements** - Environmental elements include factors such as ambient temperature, moisture, oxidation, lightning strikes, power surges, sunlight, and ultraviolet radiation.

- **Security: Industry Best Practices** - As cyber security and perpetrators become more prevalent and more sophisticated in how they attempt to exploit application and IT technology vulnerabilities, changes must be made and costs incurred to maintain an appropriate level of IT security. This is assessed in relation to IT industry best practices. Various reviews including application penetration testing are performed regularly to evaluate current security levels.

- **Asset Health: Pipelines greater than 30 per cent Specified Minimum Yield Strength (SMYS) -** In 2002, Union developed a software algorithm with the assistance of a third party consultant to aid in risk assessments for the pipelines greater than 30 per cent SMYS. This software algorithm, processed through an application called the Risk Analyst Tool, uses a number of probability and consequence factors to calculate a Total Risk Score for all pipelines greater than 30 per cent SMYS within Union's system. This tool was originally used to prioritize pipeline integrity inspections as part of the integrity management program at Union. As Union completed the inline inspections of its pipelines it began to focus more on managing the risks of the anomalies identified and used a risk based approach to prioritize the work. Going forward, Union will further leverage the Risk Analyst tool to focus on assessing asset health.

    - Union is now using the Risk Analyst Tool to assess the health of pipelines greater than 30 per cent SMYS. The Risk Analyst Tool analyzes a pipeline by segments of identical pipeline attributes. For each segment, a variety of factors are used to calculate both relative scores for probability of poor asset health and consequence of failures. This calculation is based on a number of different asset-related attributes for each segment that is assessed.

    - Examples of these attributes include pipe grade, wall thickness, coating type, per cent SMYS, Maximum Operating Pressure, depth of cover, and results from in-line inspection (ILI) and External Corrosion Direct

Assessment (ECDA). The Risk Analyst Tool can provide results for both individual pipeline segments as well as an entire pipeline. In addition to the scores for both probability and consequence, the tool also generates an overall risk score for both pipeline segments and entire pipelines.

  - Moving forward, the Risk Analyst Tool will be used on an annual basis to generate updated asset health data for review and assessment. The highest probability and consequence factor scores as well as the highest total risk scores will be reviewed to identify if there are any potential asset health concerns which require further engineering review. The associated factors will be verified, and if deemed appropriate, an engineering review will be initiated for the specific pipeline. The engineering review will determine if any additional measures are required to assess the integrity of the pipeline, or if the inspection frequency of the pipeline needs to be adjusted. Once the engineering review is completed, if any remediation is required, the project will be risk-ranked in accordance with Union's risk management processes and will follow Union's budget process.

- **Asset Health: Underground Storage - Storage Wells** - In 2009, Union developed a semi-quantitative risk tool that evaluates the condition of Union's storage wells. This algorithm uses risk and consequence factors to determine a total risk score for each well that can be compared to other wells. Union has used a third party consultant to help in the various weightings and risk calculation of the algorithm. The risk tool helps prioritize remediation activities by indicating the greatest risk reduction for individual well workovers.

  - The risk tool analyzes each well's attributes to calculate a risk and consequence score. Examples of these attributes include pool location, casing wall thickness, presence of corrosion, wellhead construction, cement quality, maximum operating pressure, well deliverability, distance to nearest residence, and pool size. The risk tool is updated on an annual basis to generate an updated well risk score.

- **Asset Health: All Other Assets** - While there is no specific tool to assess asset health for assets excluding pipelines greater than 30 per cent SMYS and pipes in storage wells, the health of these assets is managed through Union's risk management processes and procedures as described in Section 4.2.1.1.3.

  - As Union identifies individual asset risks or systemic issues with particular asset classes across the franchise, these risks are brought to the risk workshops where Union's subject matter experts discuss the issues and risk rank them. The responsible Asset Class Managers will then begin to plan and prioritize the necessary work required to mitigate these issues.

  - As needed, additional data is used from corporate systems such as Union's Geographic Information System (GIS) to assess failure rates and failure modes, when available, to further quantify asset health to help support asset management related decisions and capital and operations and maintenance (O&M) spend. Union also leverages industry knowledge and experience to gain external perspectives on issues that may be prevalent with other utilities across North America. As additional data and subject matter expertise is gathered and assessed, programs are created as needed to address specific asset health related risks over defined time periods determined by the associated risk severity of these issues. Many of these programs are highlighted in Section 5.5.

New or Changes to Existing Legal and Regulatory Requirements

Potential projects are identified when regulations change or Union's understanding of the regulations changes. This driver is not necessarily related to the actual condition of an asset, yet it is part of the maintenance capital budget as it is driven by a need to upgrade the asset to new standards set by changing regulations. Key standards that drive maintenance requirements are:

- Canadian Standards Association Z662–15 Oil and Gas Pipeline Systems and the Technical Standards and Safety Authority (TSSA) Code Adoption Document.
- Canadian Standards Association Z341 Storage of Hydrocarbons in Underground Formations, and the Oil, Gas and Salt Resources of Ontario Operating Standards.
- Ontario Building Code for Service Facilities.
- O.Reg.419/05 (Environmental Protection Act, R.S.O. 1990).
- Electricity Gas Inspection Act & Regulations and associated Measurement Canada specifications/bulletins.
- National Energy Board (NEB) Onshore Pipeline Regulations SOR/99-294.

The standards related to pipeline assets have resulted in the creation of a number of key Standard Operating Practices (SOPs) that address code requirements and outline how Union ensures compliance with Standards and Codes.

Contractual Obligations

Due to contractual agreements with municipalities, Union is required to relocate existing plant in cases where it conflicts with municipal infrastructure renewal projects. Union will strive to resolve conflicts by proposing alternative designs to avoid the need to relocate facilities where practical. In cases where no resolution can be achieved, Union will use this opportunity to renew facilities to ensure that an infrastructure renewal project in the near future does not result in additional disturbance to the municipality.

4.2.1.1.3 Risk Management

A number of risk management processes are leveraged to adequately assess, evaluate, mitigate, and monitor risks that are identified through a number of different channels. These processes also outline the approach to communicating these risks and seeking endorsement of risk mitigation actions to address them.

Union's risk management process uses a Risk Matrix (Figure 4.2.1.1.3.2) to provide a consistent basis on which to assess risks and prioritize mitigations. Items are raised through field input, input from subject matter experts, or evidence as derived from Union's asset systems of record (e.g., Geographic Information System). Mitigations may be in the form of process solutions or capital investments to reduce the risk to a tolerable level with a view to optimize resource expenditure.

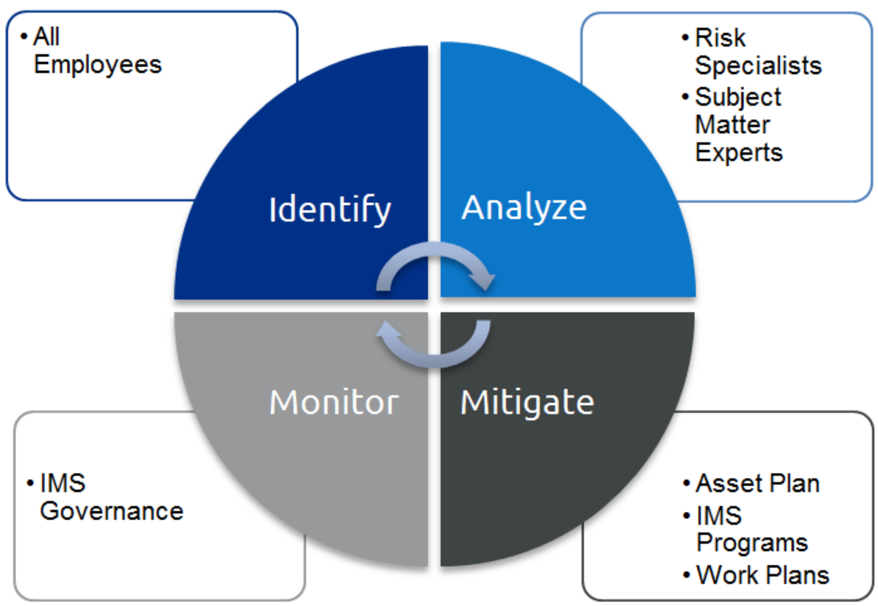


Figure 4.2.1.1.3.1: Risk management process

Hazard and Risk Identification

Operational hazard and risk identification occurs throughout each phase of the asset lifecycle. Hazards are identified through a number of different processes as identified in Table4.2.1.1.3.1. Items one to three are the primary processes used to identify hazards and risks that support asset management.

Table 4.2.1.1.3.1: Methods of Identifying Hazards and Risks

#	Source	Activity	Tactic	Description
1	Subject Matter Expert (SME)	Risk Workshops	Targeted Review	Targeted risk reviews for specific asset classes
2	SME	IMS Program Reviews	Targeted Review	Targeted reviews for specific IMS Programs
3	Asset class owners and operators	Capital Budget Process	Targeted Review	Targeted review for identified capital projects
4	All	Joint Health & Safety Committees	Targeted Review	Targeted review for occupational health and safety hazards
5	All	ILP	Reporting Tool	Specific mechanism to report hazards, concerns and issues
6	Leadership	IMS Governance	Leadership Reviews	Overarching review of hazards, risks and incidents
7	Front Line	Leak Tool	Work Management Database	Hazards identified as part of regular work for leak repairs
8	Front Line	Risk Tracker	Work Management Database	Hazards identified as part of regular work for line hits
9	Front Line	SAP PM	Work Management Database	Hazards identified as part of regular work for plant maintenance
10	Front Line	Distribution Operations Action Request (DOAR)	Reporting Tool	Specific mechanism to report hazards, concerns and issues
11	Front Line	Procedure, Equipment, Material Report (PEMR)	Reporting Tool	Specific mechanism to report hazards, concerns and issues

Newly identified hazards are reviewed and potential risks are evaluated. Based on the assessment results, a new risk may be added to the Operations Risk Registry or an existing risk may be updated. The Risk Registry is a database that is used to track all new risks that are identified and evaluated using the common risk assessment process underpinned by the Risk Matrix. All documented risks are tracked and managed in the Risk Registry through a cycle of continual reviews and updates.

Risk Analysis

Risks are assessed using a number of different approaches based on the types of hazards and assets that are under review. All risks are evaluated within the context of Union's Risk Matrix (Figure 4.2.1.1.3.2) to determine the likelihood of occurrence of the event in question and the consequence of the failure.

ALMOST CERTAIN	L5	Likelihood/Probability	III	II	II	I	I
LIKELY	L4		III	III	II	II	I
OCCASIONAL	L3		IV	III	III	II	II
RARE	L2		IV	III	III	III	II
REMOTE	L1		IV	IV	IV	III	III
			Consequence				
			C1	C2	C3	C4	C5

Figure 4.2.1.1.3.2: Union's Risk Matrix

Consequences are grouped into the following categories:

- Injury
- Regulatory
- Loss of containment
- Environmental
- Financial
- Reliability
- Reputation

The following is a list of the most commonly used types of risk assessments:

- Risk Workshops: Risk workshops are facilitated annually by the Engineer Specialist Risk Management during which SMEs in a given asset category are assembled to identify new risks and create a better understanding of previously-identified risks.
- Brainstorming: Group exercise to identify hazards and assess risks associated with a process or set of equipment. Used during regular reviews of the Risk Registry.
- Checklist review: Identify hazards, review general types of incidents, and evaluate impacts and controls in a systematic manner. Used during Risk Reviews in support of the Maintenance Capital Budget.
- Hazard and Operability Study (HAZOP): Systematic and detailed identification and evaluation of process facility safeguards with a multidisciplinary team. Used in the design phase for large capital projects.

- Reliability Centred Maintenance (RCM): Focused on required functions (based on the asset's operating context) and the functional failures that may occur. Used when focusing on developing or evaluating maintenance plan.
- Engineering Assessments: Detailed technical reviews performed by internal engineering staff or a third party consultant. Used for a detailed review of a possible systemic concern or risk.

New risks identified through these assessments are entered into the Risk Registry, and then significant risks (Risk Rank I and Risk Rank II) are presented to the accountable director, the Operations Steering Committee and the accountable vice president for endorsement.

Risk Treatment/Mitigation

Risk treatment is the mitigation of identified risks, ranging from day-to-day operations activities undertaken by operators and field personnel to inspect equipment, to a large capital project to replace an existing asset (Figure 4.2.1.1.3.3). Operating inspections, procedures and preventive maintenance activities are developed during the commissioning of an asset and are used to mitigate identified risks throughout the operations and maintenance phase of the asset lifecycle. The maintenance strategy for a facility or asset is established on the basis of Standard Operating Practice (SOP) requirements, the outputs of a maintenance strategy analysis (such as RCM) or Original Equipment Manufacturer (OEM) recommendations.

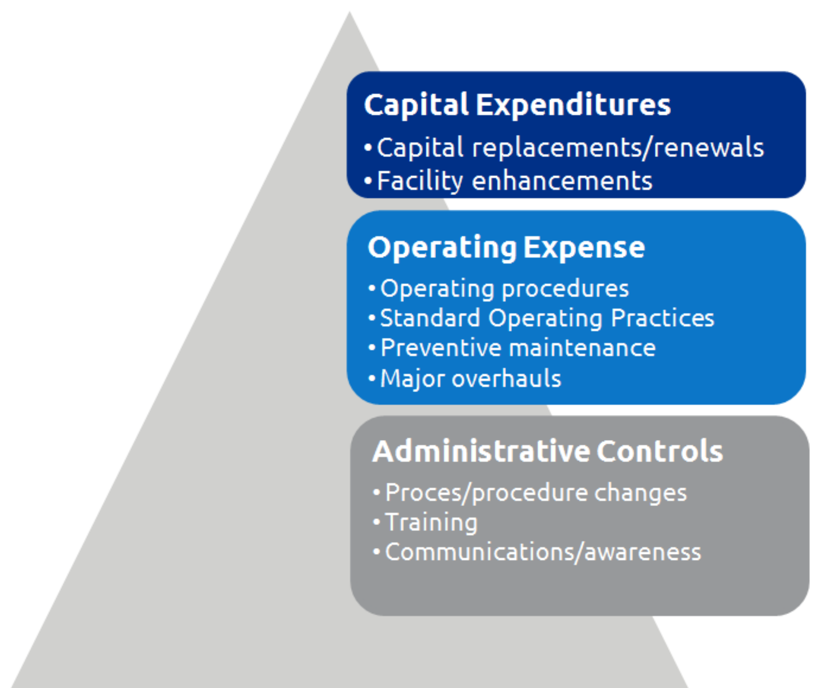


Figure 4.2.1.1.3.3: Spectrum of risk treatment options

4.2.1.1.4 **Project Prioritization and Selection**

The 10-year AMP is used as the starting point for the annual capital budget process, which determines the budget for the following year. Through the budget preparation process, the risks that each project is mitigating are re-evaluated and endorsed. It is at this point that new projects may also be identified to mitigate risk. Figure 4.2.1.1.4.1 outlines the budget cycle process with the AMP as the starting point.

Figure 4.2.1.1.4.1: Annual Budget/Asset Management Plan Cycle

As there are finite resources to complete maintenance capital projects, projects are selected for the AMP on the basis of their relative priority. All projects are evaluated and prioritized using a common methodology to ensure that maintenance capital resources are employed to address the highest priority items across all asset categories.

Union has developed a consistent methodology for prioritization of all projects, as depicted in the figure below. The figure shows that there are projects of a higher priority nature at the top of the graphic to lower priority projects at the bottom. It is also important to note that the projects toward the high priority end of the spectrum have inherently less flexibility on the level of expenditure and timing. As we move down the priority spectrum, there is an increasing level of flexibility in expenditures and timing.

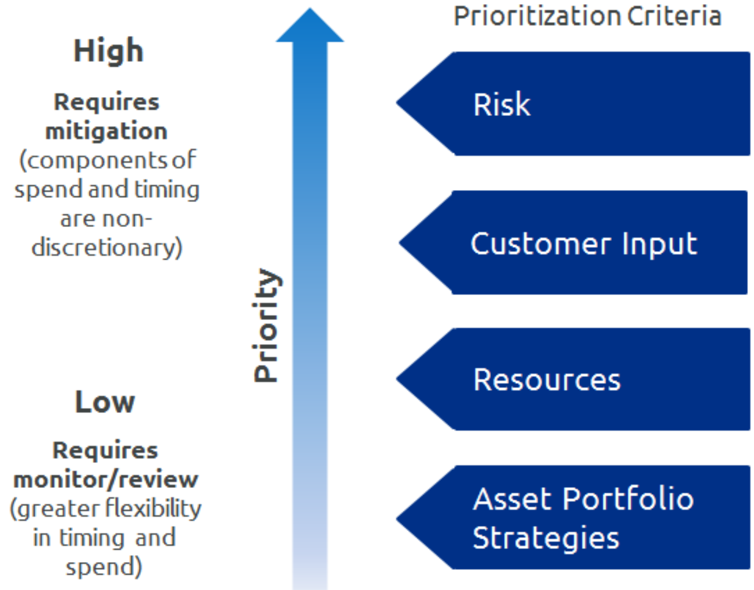


Figure 4.2.1.1.4.2: Asset Management Plan prioritization criteria

Maintaining a mix of high priority and low priority projects allows for adjustments to be made as circumstances change. If, for whatever reason, a high priority project is identified in a given budget cycle, a lower priority project may need to be displaced to provide needed capital resources.

Several criteria are used to consistently prioritize all projects and portfolio strategies within in the overall maintenance capital portfolio (Figure 4.2.1.1.4.2).

- Risk is one of the most important criteria, and is assessed using Union's risk management process. Risk is a combination of likelihood of the event and consequence of that particular event.
- Customer input and preferences, as obtained through various customer engagement activities, are carefully considered when making strategic asset maintenance decisions. Union's 2017 customer engagement survey showed that customers have an overwhelming preference to maintain a steady pace of spend to keep the system healthy in the long run.[1] Evidence of Union's commitment to a steady pace of spend on assets can be seen in the overall 10-year maintenance capital outlook in Section 5. The project descriptions found in Appendix D share more detail on how specific results of the customer engagement survey were considered.

[1] Unless otherwise stated, the results presented relate to residential customer feedback.

- Resource availability is also used to assist in project selection. Given a number of projects of equal priority (or risk), workload distribution is used to make final decisions of which projects will proceed in a given year.
- Asset portfolio strategies are important decision criteria that are used to select certain projects over others. These strategies are given higher priority to ensure continuity in addressing a broader issue holistically.

Union uses a simple priority ranking scale of 1 to 4 to help to organize the entire capital portfolio and to ensure that the highest priority work is identified and planned accordingly.

Table 4.2.1.1.4.1: Priority ranking scale

Priority Level	Examples
1	• Compliance-related items • Growth • Contractual obligations • Risk Rank I items
2	• Risk Rank II items • Specific portfolio strategies (bare and unprotected steel replacement) • Baseline maintenance spend (tools, emergency blanket spend)
3	• Risk Rank III items
4	• Risk Rank IV items • Other low-priority items

Items that are classified as Priority 1 are considered mandatory and timing is usually inflexible. Risk Rank I projects are considered a significant risk that is intolerable and requires notification to the president within 48 hours of discovery. Short-term mitigation plans must be put in place in less than four weeks and the target to implement long-term mitigations is less than six months. In cases where this is not possible, specific approvals must be attained. Although the Priority 1 category is comprised of more than just Risk Rank I items, all items in this priority level are treated with a high degree of urgency.

Projects that are rejected must be reprioritized to a subsequent year in the asset plan using the criteria identified in Table 4.2.1.1.4.2 Figure 4.2.1.1.4.3 outlines the decision process for prioritizing the budget and the subsequent years within the AMP. Projects that are rejected from the current budget are moved into the following year of the plan, reprioritized and ultimately accepted or rejected for that year of the plan. Projects that are subsequently rejected are moved into the following year, and the process is repeated for each year of the plan. This process ensures that the highest priority work is planned in each year based on the best information at the time the plan is created. In the case of a lower risk project, the process will continue to push the project to future years. This approach enables Union to track and monitor issues that have been raised so they are not missed and can be revisited to determine if the risk associated with the issue has changed.

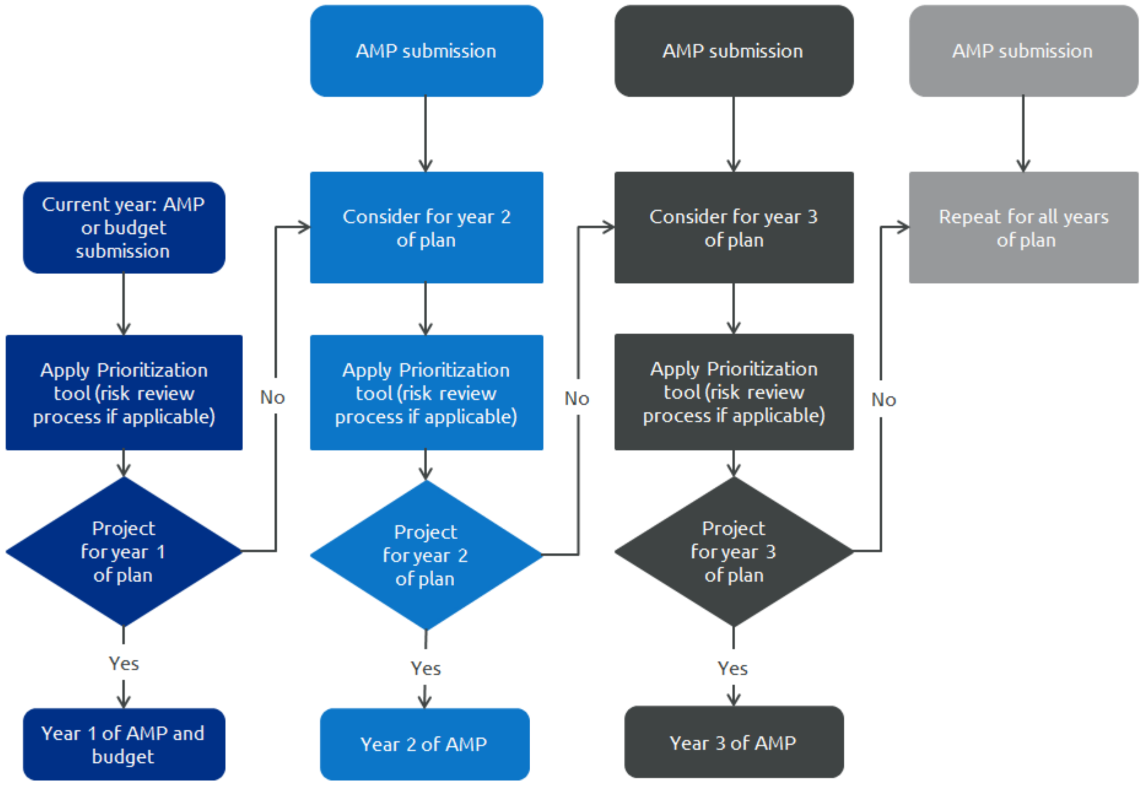
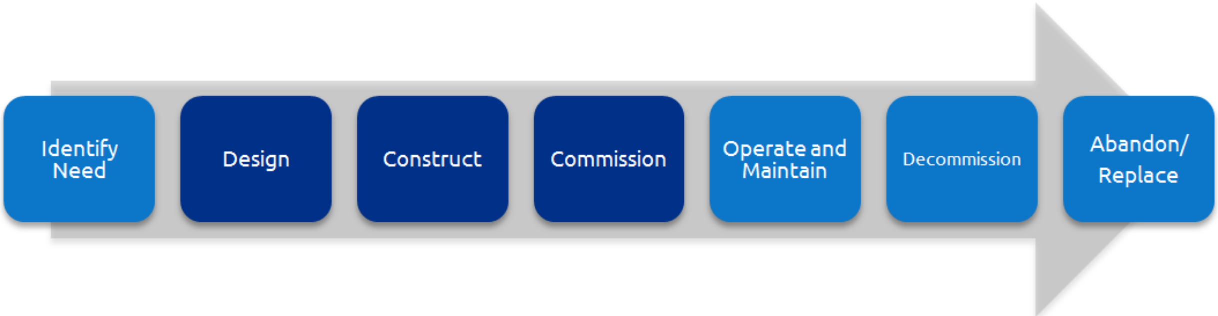


Figure 4.2.1.1.4.3: Annual prioritization flow of Asset Management Plan projects

4.2.1.2 Design, Construct and Commission



Whether it is a project that is designed by internal engineering resources or by external design firms, a strict set of design and construction specifications are followed. It is understood that the proper design, installation/construction and commissioning will affect the performance of the asset throughout the asset lifecycle. Decisions made in these phases will have a profound impact on the health and performance of the asset through the operation and maintenance phases.

4.2.1.2.1 **Integrated Resource Planning**

Consumers have the right to safe and reliable service, as well as the right to access available energy conservation programs. In response to the Ontario Energy Board's (OEB) case EB-2015-0029, Union has filed a Joint Transition Plan on how it anticipates integrating the supply and demand side processes. The Transition Plan lays the groundwork for a pathway to consider Integrated Resource Planning (IRP) over the coming years. This plan will aid in the coordination between distribution planning processes and analysis, and low carbon alternatives, including energy efficiency. IRP at Union refers to a multi-faceted planning process that includes the identification, preparation, and evaluation of all realistic supply-side and demand-side options to determine the least cost and lowest risk approach in addressing transmission and distribution infrastructure requirements. The IRP process could include:

- A review of a variety of different low carbon options such as energy efficiency to defer existing regional and local infrastructure.
- The impact of net-zero ready subdivisions and behind-the-meter solutions.
- Distributed energy resources (e.g., renewable natural gas).
- The interplay of these various energy options and the subsequent impact on infrastructure to meet system demand.

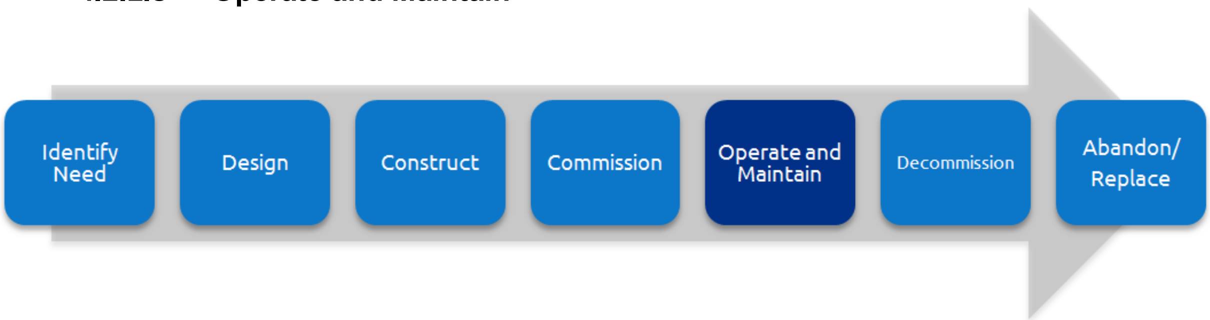
Although the supply and demand side options considered within IRP can be quite broad, in recent years, much of the discussion has focused on the impacts of Demand Side Management (DSM) and energy efficiency. At Union, DSM focuses on broad-based annual savings across the franchise areas that drive maximum bill reduction, versus a jurisdictionally-bound, peak-hour load reduction to influence supply planning. Currently, DSM plans account for potential savings in system-wide infrastructure (created by DSM savings through avoided distribution costs). On the other hand, infrastructure planning is based on a long-term load forecast intended to:

- Identify potential system constraints leading to incremental infrastructure requirements.
- Develop plans prior to the need for new infrastructure.

The primary goal of infrastructure planning is to ensure that the utility's infrastructure is sufficiently robust to provide reliable and safe natural gas service that meets the design condition peak hour requirement forecast. The impact of broad-based DSM programs on infrastructure investment is inherently captured in the infrastructure planning process. Historical gas throughput is used as a base to predict future consumption and is updated each year. These historical forecasts include changes in gas usage resulting from implementation of historical DSM measures, as well as other natural conservation factors such as improved building codes and higher energy efficiency standards for natural gas equipment. The infrastructure plans do not explicitly factor in future projections of DSM program effects on peak day or peak hour demand as they are not known and therefore not certain.

As Union's IRP and DSM programs evolve, there will be increased clarity around any subsequent impacts of these initiatives on peak period demand, further informing infrastructure planning and forecasting processes. IRP will continue to be monitored as part of Union's Asset Management Plan to ensure advancements made are acknowledged and incorporated during asset investment planning.

4.2.1.3 Operate and Maintain



The operation and maintenance phase of asset's life is the longest, and the success of this phase largely determined by decisions made in the previous two phases (construct and commission). The manner in which the asset is operated and maintained will have a direct impact on its performance and longevity. Through this phase, incremental operation and maintenance (O&M) expenditures are typically identified to support changes in maintenance plans (e.g., new technology, new regulations).

4.2.1.3.1 **Asset Operation**

It is important that the operator of the asset understands its capabilities, as operating an asset in a manner that demands more than it was designed for will have a negative impact on its health and performance, resulting in premature degradation. Operating procedures are developed for physical assets to outline the acceptable range of operation and the limits of the asset performance. For many assets, there are controls in place to raise alarms when certain detrimental operating conditions occur.

4.2.1.3.2 **Asset Maintenance**

The purpose of maintenance is to preserve the required level of performance of the asset. This is accomplished through a variety of maintenance strategies that range from a simple run-to-failure strategy, to continuous condition monitoring and condition-based maintenance. The type of maintenance strategy used is selected to adequately address the consequence of failure of the asset, within the limits of technical feasibility of proactive tasks to identify potential failures.

Although maintenance tactics differ somewhat amongst the various asset categories, the same types of strategies are employed in each. All asset categories have two major groupings of maintenance activities: preventive and corrective. Generally, preventive maintenance consists of all activities performed to prevent a functional failure of the asset; whereas corrective maintenance describes all activities performed to restore the performance of the asset to its desired standard. Corrective maintenance can be either proactive, in the case where the corrective action is completed prior to point at which the asset can no longer perform its required function; or, reactive which is typically referred to as break/fix.

Pipelines greater than 30 per cent Specified Minimum Yield Strength (SMYS) are monitored using inline inspection (ILI) or External Corrosion Direct Assessment (ECDA) at a prescribed frequency as part of the Pipeline Integrity Management Program, Class

Location Surveys and Depth of Cover surveys. Any anomalies that are identified during an ILI run will be assessed using Union's Pipeline Integrity Engineering Reference Manual practices, which may drive pipeline maintenance. This program is an example of condition monitoring techniques to identify potential failures early allowing for good planning and scheduling of intervention at the right time.

Across the physical asset classes, there is generally a heavy reliance on inspections and condition monitoring to identify potential failures. There are a number of key Standard Operating Practices (SOPs) that are generally based on code requirements for inspection and maintenance of natural gas assets. These SOPs typically prescribe a required minimum inspection frequency, the scope of the inspection as well as the requirements to complete remedial actions to correct identified deficiencies.

In general, inspections are a form of condition monitoring with tasks and inspection points designed to identify certain expected failure modes that may be present. A repair or restoration task is only undertaken in the event that an impending failure is identified.

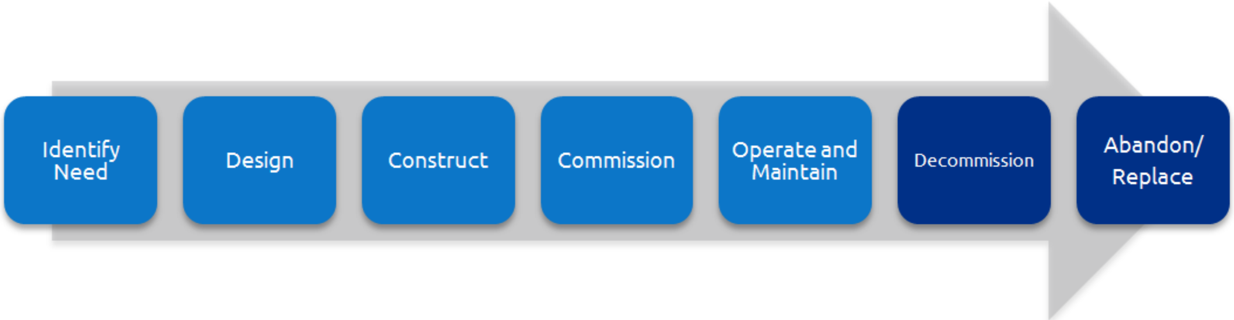
Time-based maintenance activities are those that occur at a pre-determined interval (either calendar time or run hours). Time-based activities are often referred to scheduled restoration, discard or renewal. Examples of scheduled maintenance tasks include:

- Scheduled replacement of diaphragm meters.
- Scheduled restoration of gas turbines based on Original Equipment Manufacturer (OEM) recommended overhaul interval.
- Technologies such as workstations, servers, network devices, databases and integration tools are upgraded every three to four years to maintain vendor support, performance, reliability and provide higher levels of security.

One approach to defining asset maintenance strategies that is seeing wider adoption at Union, particularly in the realm of rotating equipment, is Reliability Centred Maintenance (RCM). RCM is a very prescriptive approach to developing a maintenance program that begins with a clear understanding of the asset function. The maintenance tactics are derived as a means to preserve the required function of the asset. This is accomplished by identifying all functions of the asset and its functional failures and failure modes.

RCM then determines a consequence for each failure mode and applies a decision matrix that leads to the optimal solution or maintenance strategy to reduce or eliminate the consequence of each identified failure mode. This approach also requires the developer to question the economic business case of the suggested action to avoid over-maintaining the asset where the consequence does not warrant the effort to avoid it; a situation that results in the very legitimate maintenance strategy of run-to-failure.

4.2.1.4 Decommission and Abandon/Replace



When the asset reaches the end of its life, meaning the cost to continue to operate and maintain the asset are greater than the cost of replacing it, or the risk of continuing to operate and maintain it becomes too great, a number of alternative solutions are identified. These various alternatives are evaluated and one is ultimately selected and proposed in the AMP and subsequently included in the maintenance capital budget based on risk assessment and economic analysis. In the event that the selected solution is to retire, decommission or abandon the asset, there are a number of important considerations, including minimizing residual liabilities through the disposition of obsolete inventory, operating procedures, maintenance plans and records. These changes are managed using a number of tools such as the Management of Change (MOC) process.

4.3 Facility Greenhouse Gas (GHG) Abatement

Union is committed to the ongoing review of opportunities that will reduce greenhouse gas emissions from its natural gas transmission, storage and distribution operations in future years. Recent feasibility studies have identified several potential facility abatement opportunities that would lead to a reduction in methane and carbon dioxide emissions over the next ten years.

With recent changes in provincial government policy, Cap and Trade regulations are no longer the driving force for facility greenhouse gas (GHG) abatement. However, starting January 1, 2019 the Government of Canada intends to implement a carbon pricing system in any province that does not have a carbon pricing system that meets the federal benchmark. This federal legislation will implement carbon pricing that could support economic facility abatement initiatives in the future. Additionally, a new federal regulation targeting the reduction of methane will come into effect in 2020-2023 and a proposed Clean Fuel Standard is expected to come into effect in 2022 or 2023. The introduction of these new requirements will have impacts, which are yet to be determined, on facility GHG emission requirements. Union will continue to monitor these emerging issues and will adjust its long-term strategy and plans accordingly.

Results of Union's 2017 customer engagement study (telephone survey) showed that given the option of maintaining the status quo or paying an additional 50 cents per year for Union to reduce its GHG emissions beyond what is regulated, 58 per cent of residential customers would prefer to pay for the additional reduction. However, one third (33 per cent) say Union should not go beyond the regulated emissions requirement. Nine per cent either weren't sure or didn't have a strong opinion.

Results showed that commercial customers are not quite as willing as residential customers to pay for additional reductions in GHG emissions: almost half (49 per cent) would agree to a 2 dollars per year increase in rates for an additional 25 per cent in emissions reductions, but 42 per cent say Union should meet but not exceed the regulated requirement. Fewer than one-in-ten (8 per cent) did not offer an opinion.

Union will continue to develop criteria to appropriately evaluate potential facility abatement opportunities to ensure the implementation of initiatives effectively balances customer preferences, compliance obligations, anticipated future regulations, and other noteworthy benefits such as safety and operational reliability. This includes how the cost of carbon should be assessed, alongside other operational considerations, when evaluating system expansion alternatives.

4.4 Incremental Operations and Maintenance Expense

Within the scope of this plan are considerations related to incremental increases in operation and maintenance (O&M) expenses. For the purposes of identifying changes to the overall plan, only incremental changes relative to the base year (2018) are discussed. Specifically, the incremental O&M discussed in this plan are those items which have a direct connection to the asset management activities.

New programs or projects are directly attributable to items that require a change in how Union conducts its operation. Examples include new regulations resulting in the need for increased expenditures to maintain compliance; or, new programs to enhance inspection and maintenance programs to mitigate some identified risk.

A key input to Union's investment decisions is the trade-off between capital and O&M expenses. In cases where O&M and capital alternatives are available, both are evaluated to determine the solution that provides the best overall value. Section 5 details the incremental O&M expense associated with each asset category along with a description of the item and the driver for the increase. Union also needs to manage cost pressures on the base business. These pressures are typically not due to new programs or regulations driving the need for increased spending, rather they are the result of more gradual changes, such as inflation. Although these are not quantified in the Asset Management Plan, they are identified through the planning process, noted in the Plan, and factored into both the budgeting process, and into the asset management planning process as inputs into the costs used to assess alternatives.

5 Customers, Assets and Asset Categories

5.1 Overview of Customers and Asset Classes

Union has a network of natural gas assets that serve to receive, store, transport, and distribute natural gas. Assets illustrated in Figure 5.1.1 can be found at Union including underground storage, compression and dehydration, transmission and distribution pipelines, and the meters and regulator stations within Union's system and at customer's premises.

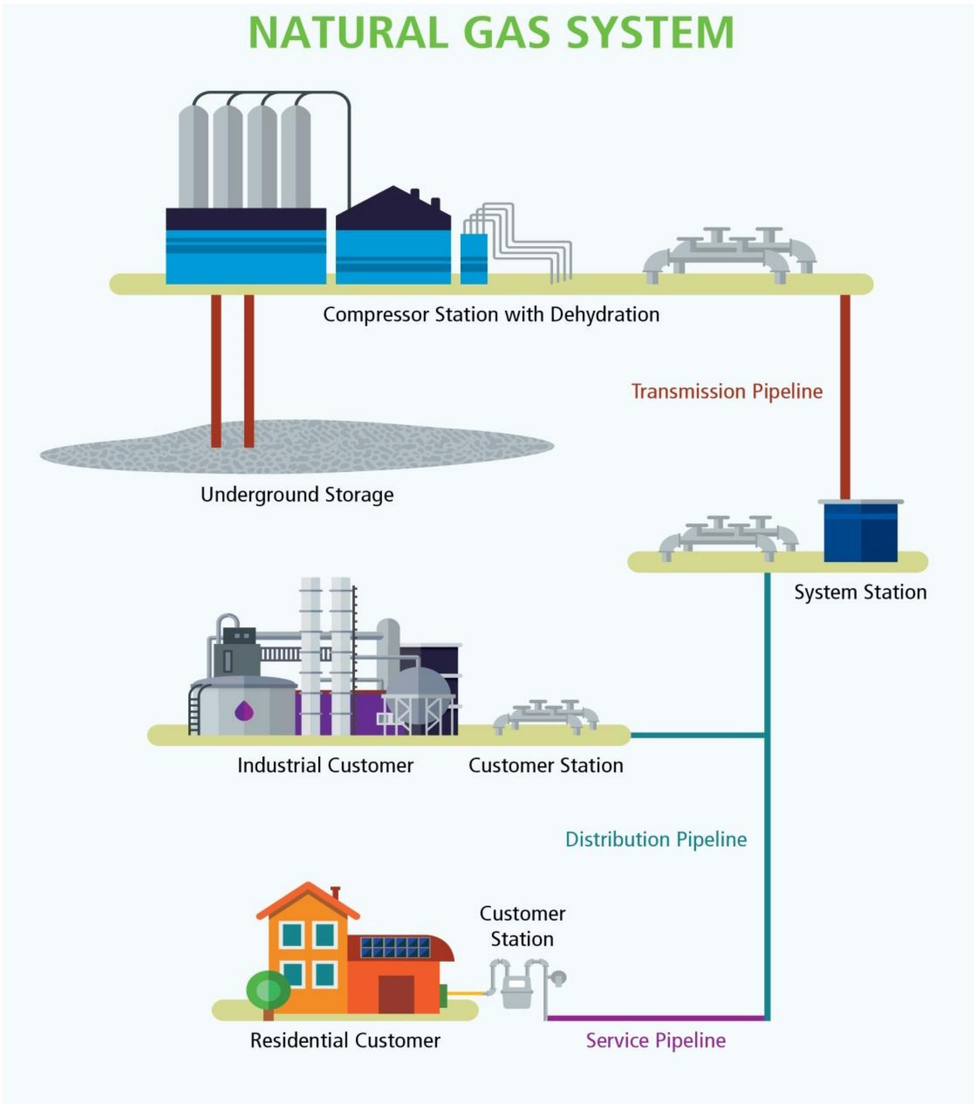


Figure 5.1.1: Components of a natural gas system

To optimize maintenance and growth strategies, natural gas carrying assets are grouped into seven asset categories and ten associated asset classes as summarized in Figure 5.1.2. Additionally, there are three non-commodity carrying asset classes that support general operations for Union: Service Facilities (Corporate Real Estate Services CRES), Fleet, and Technology and Information Services (TIS). More detail about each asset class is summarized in Section 5.4.

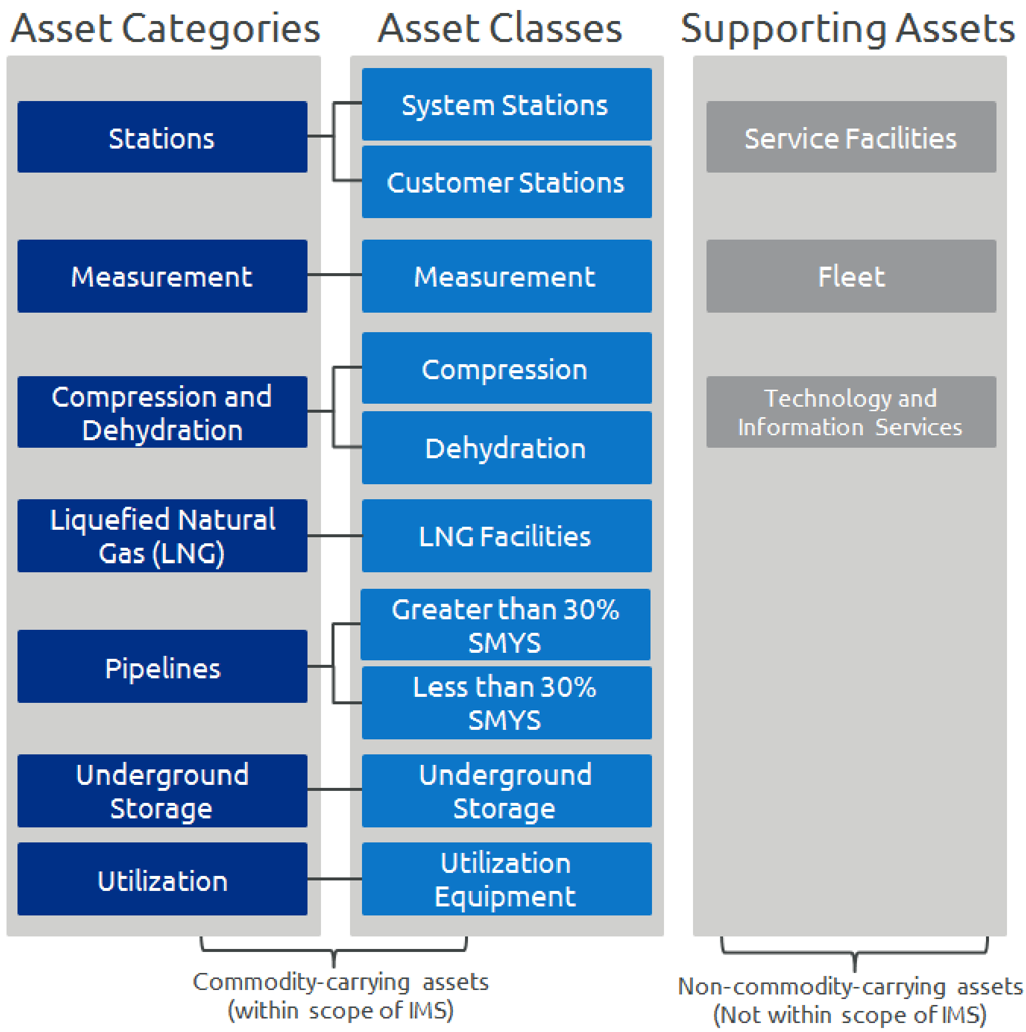


Table 5.1.2: Asset Categories, Asset Classes and Supporting Assets

5.2 Customers and Customer Growth

Union serves approximately 1.5 million customers in the Province of Ontario. These customers are referred to as in-franchise customers and are grouped into three main categories:

Residential

Residential customers are supplied for residential purposes in a single family dwelling or building, an individual flat or apartment within a multiple family dwelling or building, or a portion of a building occupied as the home, residence, or sleeping place of one or more persons.

When service for residential purposes is supplied to two or more families served as a single customer under one rate classification contract, that service is considered as commercial but is counted as only one customer. Residential premises also used regularly for professional or business purposes (e.g. doctor's office in a home or a small store in a home integrated with the living space), are considered as residential where the residential use of gas is half or more than half of the total service.

Commercial

Commercial customers are considered as customers who are engaged in selling, warehousing or distributing a commodity, in some business activity or in some other form of economic or social activity (also includes professions). The size of the customer's operation or volume of use is not a criterion for determining commercial service.

Industrial

Industrial customers are those engaged in a process which creates or changes raw or unfinished materials into another form or product, or who change or complete a semi-finished material into a finished form. All gas used on premises which qualify under the industrial classification is classified as industrial service. The size of the customer's operation or volume of use is not a criterion for determining industrial service.

Contract and Non-contract

In-franchise customers are served either by non-contract or contract rate classes. Customers in the contract rate classes tend to be larger volume consumers of gas who have made a term, volume, and storage commitments as part of their service. Non-contract customers are typically residential users and smaller commercial and industrial operations that have made no contractual commitment for service from the utility.

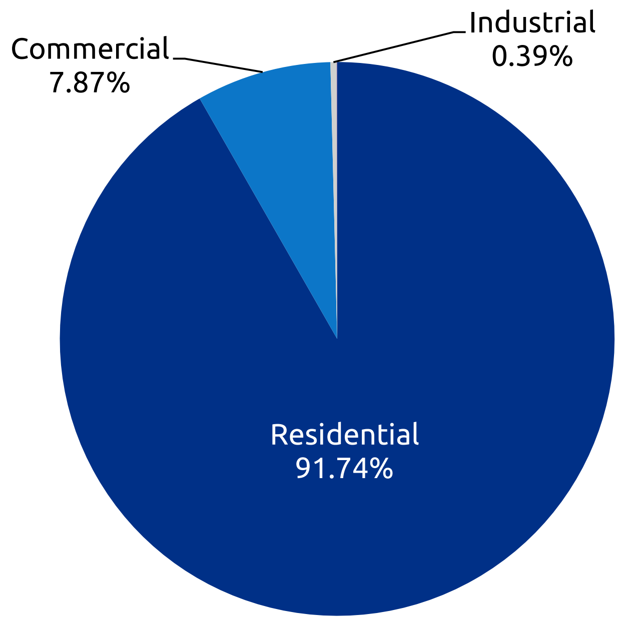


Figure 5.2.1: Breakdown of Union's customer base - by customer type

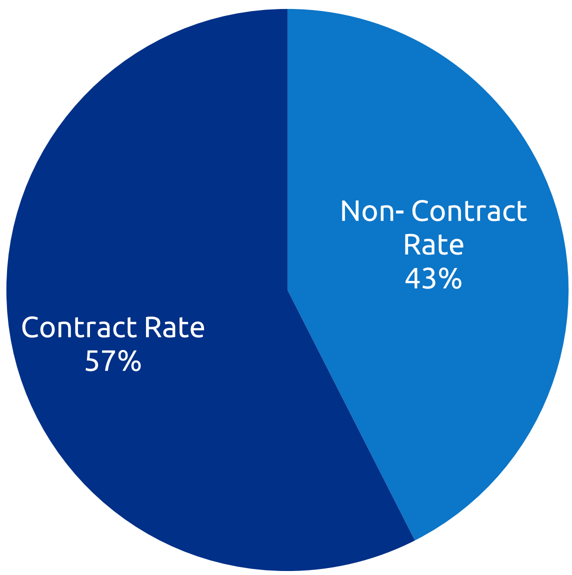


Figure 5.2.2: Breakdown of Union's customer base - volume per rate class

Figures 5.2.1 and 5.2.2 demonstrate that while the residential sector makes up the majority of the customers by count, the contract customer segment is by far the largest by volume. There are a large number of contract customers across the franchise representing a very important component of Union's business. Union manages these large contract customers through an account management process. Union regularly pursues growth in the contract rate customer growth segment, through the expansion of existing customers as well as the addition of new customers to the system.

Customer growth is grouped into two main categories:

- Distribution growth.
- System growth.

Distribution growth is associated with customer growth on the distribution system, whereas system growth is associated with customer growth on transmission systems. The following graphic depicts the breakdown of the Union's customers by type.

5.2.1 Distribution Growth

Table 5.2.1.1: Distribution Planning 10-Year Growth Summary (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
General Customer Growth	68.9	69.7	65.7	67.0	73.3	74.6	71.1	82.5	73.9	80.4	**727.1**
Community Expansion	6.8	0.1									**6.9**
CK Rural	16.2	0.4									**16.6**
Distribution Reinforcement	9.8	7.1	7.2	9.6	21.4	8.3	9.3	9.3	30.6	8.9	**121.6**
Station Reinforcement	1.4	3.9	10.8	21.4	35.8	18.7	1.7	1.7	0.4	2.1	**97.8**
Transmission Reinforcement	33.3	51.5	12.3	15.9	9.8	6.6	48.7	39.5	20.5		**238.0**
Distribution Planning Total	**136.3**	**132.7**	**95.9**	**113.9**	**140.3**	**108.3**	**130.8**	**132.9**	**125.3**	**91.4**	**1,207.9**

General Customer Growth

General Customer Growth is the forecast to attach new general service customers and new contract rate customers in the distribution systems and is based on the forecasts provided in Table 4.2.1.1.1.1. The forecast value is determined by applying a five-year historical average cost to attach customers to the forecast number of attachments as outlined in Table 5.2.1.1. The costs associated with general service include the mains and services to attach the customer as well as the costs associated with the meter and regulator installation at the customer's site.

This item also contains the forecast associated with attaching large contract customers. Historically, Union attaches one large contract customer every two to three years. At any given time there are a number of potential contract rate customers that are either seeking access to Union's system or are seeking an increase in their contracted volume. Based on discussions with these potential customers, a forecasted volume is calculated and used to estimate the capital requirements to attach the new customer or to increase the contracted volume.

Community Expansion

In response to the Ontario Energy Board's (OEB) initiative to address the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas,[1] Union has filed proposals with the OEB designed to facilitate enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in the province.

The availability of natural gas in community expansion project areas will create a number of benefits, both from a customer and community perspective. Not only will natural gas provide annual energy savings for customers, it will also result in reduced costs and increased efficiencies for existing businesses. The expansion of natural gas to these areas will help remove economic barriers.

Union's initial Community Expansion proposal[2] focused on four projects:

- Chippewas of Kettle and Stony Point First Nation and Lambton Shores.
- Milverton, Rostock and Wartburg.
- Prince Township.
- Delaware Nation of Moraviantown.

The OEB has granted approvals for the four projects and they will be in service by the end of 2018.

On July 30, 2017, Union submitted grant applications to the Government of Ontario (the Government) for 45 community expansion and five economic development projects based on funding from the Natural Gas Grant Program. On April 3, 2018, the Government announced grant funding for 11 projects, which includes up to $22 million in grant funding for four projects proposed by Union:

- Chippewas of the Thames First Nation.
- Delaware Nation of Moraviantown.
- North Bay (Peninsula and Northshore Roads).
- Saugeen First Nation.

The Delaware Nation of Moraviantown Project received rates approval from the OEB in 2017. In May 2018, Union filed an application with the OEB seeking approvals to serve the communities of the Chippewas of the Thames First Nation, North Bay (Peninsula and Northshore Roads) and Saugeen First Nation.

The recently elected provincial government indicated that the Natural Gas Grant Program would be terminated in the fall of 2018.[3] Union is awaiting the introduction of new legislation that is being developed by the provincial government to encourage private sector investment in the expansion of natural gas in Ontario. Union is seeking

[1] Minister of Energy correspondence dated February 17, 2015 and OEB invitation for parties to submit a community expansion proposal dated February 18, 2015.
[2] EB-2015-0179 updated application and evidence dated March 31, 2017.
[3] The funding agreement for Delaware Nation of Moraviantown was already executed and therefore was not withdrawn.

further clarification on intent and consequently notes that the above projects may be subject to deferral or cancellation as a result of restricted government funding. Depending on the mechanisms provided to incent private sector investment in similar projects, Union may make additional community expansion project proposals over the next few years.

In October 2016, Union and EPCOR Utilities Inc. (EPCOR) both filed Common Infrastructure Plan Proposals to serve the area covered by the South Bruce Expansion application. An OEB administered process to determine the successful competing project proponent was completed, and in April 2018, the OEB selected EPCOR to provide natural gas distribution service to the South Bruce Expansion area. EPCOR's proposal is expected to be supplied from Union's pipeline system and required reinforcement of the Owen Sound Line is under development.

Chatham-Kent Rural Expansion

In order to provide opportunities for economic growth within Chatham-Kent, Union is proposing to install a 500 m NPS 12 steel 6,040 kPa pipeline and a 13 km NPS 8 steel 6,040 kPa pipeline to boost system capacity across the Chatham-Kent region.

Distribution, Station and Transmission Reinforcement Projects

Reinforcement includes the reinforcement projects identified through the Facility Business Plan (FBP) process. These projects are important to meet the forecasted growth and will ensure Union is able to serve and satisfy those customers. For a detailed description of each of the projects in the distribution growth forecast, refer to Appendix D. The appendix is divided into the following Sections:

1. Growth
2. Pipelines
3. Stations
4. Compression and Dehydration
5. Liquefied Natural Gas
6. Measurement
7. Underground Storage
8. Service Facilities
9. Technology and Information Services (TIS)

The project descriptions include a discussion on the scope, the need for the project and timing and expenditures. There is also discussion regarding the alternatives that have been considered in in determining the solution that best meets identified needs and addresses the risk or opportunity. Alternatives and proposed solutions are still being investigated for projects that are projected to begin in coming years. As the need for the project grows and the estimated start date draws nearer, detailed analysis of alternatives and more precise cost estimates help to determine the optimal solution.

5.2.2 System Growth

5.2.2.1 Summary of System Growth Forecast

Table 5.2.2.1.1: System Planning 10-Year Growth Summary (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Kingsville Transmission Reinf Project	93.8	2.8									**96.6**
Panhandle	0.5					0.3	12.8	94.7	4.9		**113.1**
Sarnia Industrial System	3.0	60.4	1.3								**64.7**
Dawn Parkway System	8.5										**8.5**
System Planning Total	**105.8**	**63.2**	**1.3**			**0.3**	**12.8**	**94.7**	**4.9**		**282.9**

Kingsville Transmission Reinforcement Project and Panhandle System

The Panhandle System expansion is driven by in-franchise growth in Chatham-Kent, Windsor-Essex and surrounding areas, including the fast growing greenhouse market in the Leamington/Kingsville area. The forecast includes the Kingsville Transmission Reinforcement Project consisting of approximately 19 km of nominal pipe size (NPS) 20 pipeline which is driven by an increased growth forecast along the Panhandle System. The Panhandle System costs include clean-up costs in 2018 associated with OEB case EB-2016-0186 Panhandle Reinforcement Project. Additional Panhandle System facilities are planned for construction in 2024 and include the construction of approximately 14 km of NPS 36 pipe looping the existing NPS 20 from Dover Transmission Station towards Comber Transmission Station. These facilities will provide in-franchise customers in the Chatham-Kent, Windsor-Essex and Leamington/Kingsville areas increased access to low-cost natural gas for use in their homes and businesses.

Sarnia Industrial Line System

The Sarnia Industrial Line System expansion is driven primarily by in-franchise industrial contract rate growth. The forecast includes a project to directly serve new industrial customers in the TransAlta Energy Park and to serve increased demand for existing industrial customers. If demand continues to increase, additional reinforcement of the Sarnia Industrial Line System will be required. The costs and timing of these facilities has not been determined.

Dawn to Parkway System Expansion

Years 2018 and 2019 of the Dawn Parkway System forecast include the remaining commissioning and clean-up costs from the installation of the 2017 Dawn H, Lobo D and Bright C compressors. Future Dawn to Parkway System expansion is not currently forecasted as the expansion is primarily driven by changes to North American natural gas market fundamentals where shippers look to access economic natural gas supplies. Union will periodically conduct a transportation open season to gauge market demand. Should demand increase along the Dawn to Parkway System, it is anticipated that the next facilities required will be NPS 48 Kirkwall to Hamilton, NPS 48 Dawn to Enniskillen, and Milton to Parkway. The costs or timing of these facilities has not been determined. These facilities will provide ex-franchise customers additional access to the liquidity, storage, and transportation services available at the Dawn Hub to meet their market needs.

5.2.3 Growth – Other

A new area of growth for Union is Compressed Natural Gas (CNG) and Liquefied Natural Gas for vehicles (LNG). Projects forecast in these areas are expected to support low carbon fueling and production for Canada's Clean Fuel Standard.

5.2.3.1 Summary of CNG/LNG Growth Projects

Table 5.2.3.1.1 Summary of CNG Growth Projects 10-Year Growth Summary (all $ in millions)

Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
CNG Growth	1.0	2.3	1.9	1.9							**7.0**

Compressed Natural Gas (CNG)

Union's Highway 401 CNG project, which is being included under the unregulated Union Affiliate Union Energy Solutions (UES) Limited Partnership will establish key heavy-duty truck CNG refuelling infrastructure on Canada's busiest trucking corridor. It will be accomplished in conjunction with leading, Canadian industry providers of CNG solutions. The project scope will encompass all aspects of engineering, approvals, procurement, construction, commissioning, and ongoing operation and maintenance of three refueling stations at strategic locations along the Highway 401 corridor including Windsor, London and Eastern Ontario (Napanee).

The objective of this project is to provide the reliability and attractive pricing that is critical for the many fleets that regularly use the Highway 401 corridor to make long-term CNG adoption decisions for their operations. Growing CNG penetration in Ontario is strategically significant as it allows Union to grow natural gas consumption while simultaneously reducing Ontario's greenhouse gas (GHG) emissions. Moving forward with this project will allow Union to leverage federal government incentive funding and its early mover advantage.

Construction and operation of new CNG fueling stations by third parties is also expected to occur and Union will need to provide the gas distribution facilities (mains, services, meter stations) required to supply these CNG stations. The price of competing diesel fuel and availability of government incentive programs will be critical factors underpinning growth in this sector. The revenue forecast assumes these factors are conducive to growth and result in the following new stations and associated capital to supply natural gas service:

- 2019: Seven stations $1.00 million
- 2020: Six stations $2.250 million
- 2021: Five stations $1.875 million
- 2022: Five stations $1.875 million

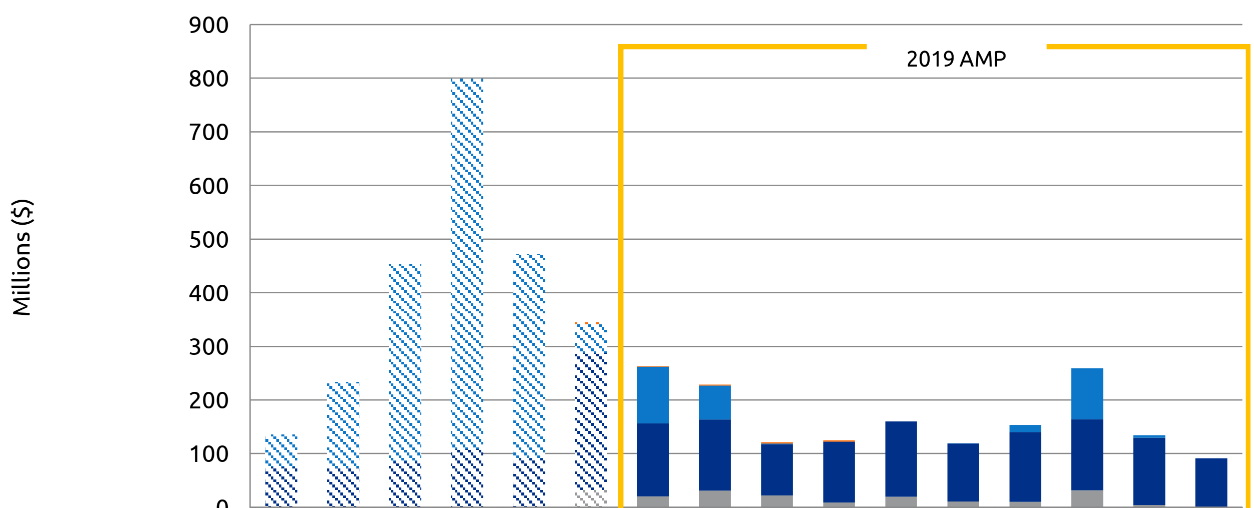
5.3 Asset Growth Recommendations

Table 5.3.1 and Figure 5.3.1 summarize the asset growth financial forecast to meet customer growth needs for the period of the AMP. Larger projects have an impact on certain years. Impacts can be seen from major distribution and system growth projects including growth from Community Expansion in 2018/2019, growth on the Panhandle System in 2019 and 2024, and growth on the Sarnia Industrial Line System in 2023.

Distribution growth is based on a forecast that incorporates historical growth with econometric factors. System and Storage Growth are based on a combination of an econometric forecast and ex-franchise growth. There is no ex-franchise growth forecast in this plan.

Table 5.3.1: Asset Growth 10-Year Capital Forecast (all $ in millions)

Project/ Program	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Other - CNG	1.0	2.3	1.9	1.9							**7.0**
Distribution Growth	136.3	132.7	95.9	113.9	140.3	108.3	130.8	132.9	125.3	91.4	**1,207.9**
System Growth	105.8	63.2	1.3			0.3	12.8	94.7	4.9		**282.9**
Growth Total	**243.1**	**198.1**	**99.1**	**115.8**	**140.3**	**108.6**	**143.6**	**227.6**	**130.2**	**91.4**	**1,497.8**



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Other - CNG						3.0	1.0	2.3	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
System Growth	60.3	160.2	368.0	690.0	380.0	53.0	105.8	63.2	1.3	0.0	0.0	0.3	12.8	94.7	4.9	0.0
Distribution Growth	75.4	73.6	86.3	109.4	92.1	256.3	136.3	132.7	95.9	113.9	140.3	108.3	130.8	132.9	125.3	91.4
Overheads						32.5	20.0	30.7	21.7	8.6	19.4	10.4	9.7	31.4	3.9	0.0

Figure 5.3.1: Asset Growth 10-Year Capital Forecast (all $ in millions)

5.4 Asset Class Information

The following is a summary of the seven asset categories and ten associated asset classes identified in Figure 5.4.1, as well as the three non-commodity carrying asset classes that are considered supporting assets. Each asset class contains unique properties that can be managed through similar programs and oversight.

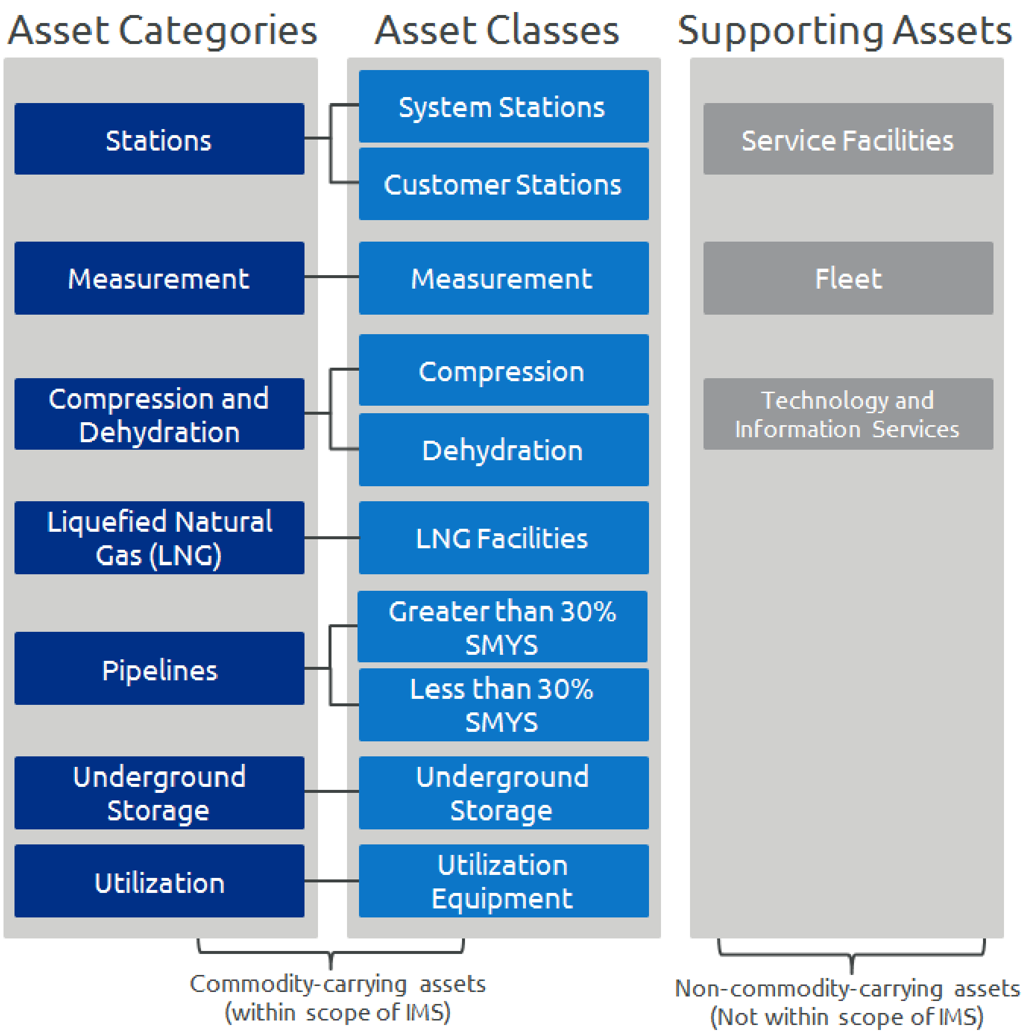


Figure 5.4.1: Asset Categories, Asset Classes and Supporting Assets

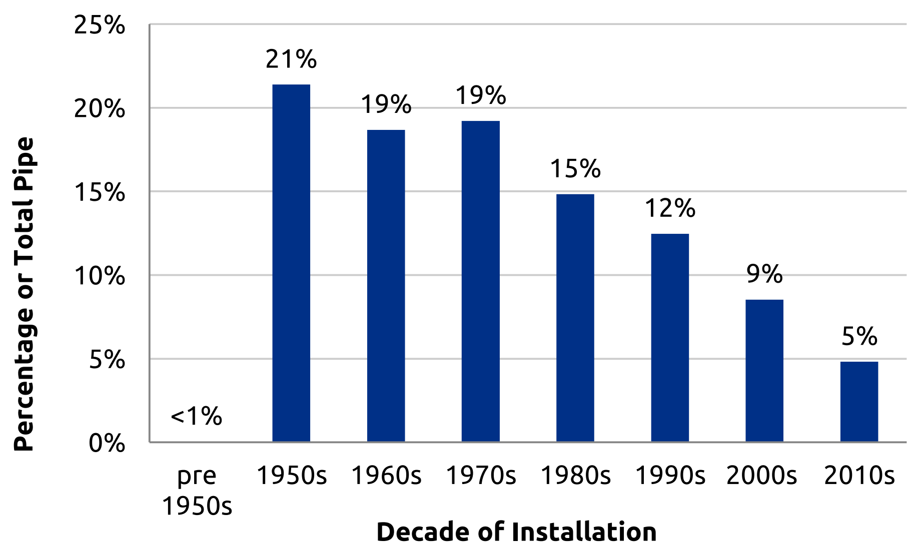
5.4.1 Pipelines

5.4.1.1 Overview of Pipelines greater than 30 per cent SMYS

This asset class contains pipelines and piping components (such as valves and fittings) that operate at or above 30 per cent of the Specified Minimum Yield Strength (SMYS) and all National Energy Board (NEB) regulated lines. This class, which includes 2,980 km of pipeline systems, consists of storage gathering systems, Union's major transmission systems and associated laterals connecting to the distribution networks, and the laterals feeding from the TransCanada pipeline system (Union's northern area) to the distribution systems and major customer stations. The majority of these pipelines have a maximum operating pressure (MOP) of 6,160 to 6,895 kPa and range in diameter from NPS 4 to NPS 48.

NEB regulated lines include the two NPS 12 Detroit River Crossing pipelines, the NPS 20 Bluewater pipeline, and the NPS 24 St. Clair pipeline. Although the two Detroit River Crossing pipelines operate at less than 30 per cent SMYS, they are included in this class to ensure they have the attention and maintenance required of National Energy Board lines. A large percentage of Union's pipelines greater than 30 per cent SMYS were installed over prior to 1980 as evidenced by the following age profile.

Figure 5.4.1.1.1: Percentage of total pipe by length versus decade of installation for pipelines greater than 30 per cent SMYS (Data used: December 31, 2017)



The major pipeline systems in this asset class are the Panhandle System, the Dawn to Parkway System, and the Sarnia Industrial Line System.

The Panhandle System consists of two parallel pipelines: NPS 12/20/36 and NPS 20. The two NPS 12 Detroit River Crossing pipelines connect the Panhandle Eastern Pipeline System to the Panhandle System and the Dawn Hub. This pipeline system supplies in-franchise customer demands from Dawn to Windsor.

The Dawn to Parkway System primarily consists of four parallel pipelines: NPS 26, NPS 34, NPS 42, and NPS 48. The NPS 26, NPS 34 and NPS 48 pipelines span the entire distance between Dawn to Parkway while the NPS 42 only runs from Dawn to Kirkwall. The Dawn to Parkway System was expanded with a second parallel section of NPS 48 from Hamilton and Milton.

The Dawn to Parkway System is used to transport natural gas to in-franchise customers located east of Dawn and west of Mississauga, and to ex-franchise customers at Dawn Compressor Station, Kirkwall Custody Transfer Station and the Parkway East and Parkway West Compressor Stations at the east end of Union South. These locations supply natural to Enbridge Gas Distribution, Gaz Métro Limited Partnership, utilities in the U.S. Northeast and others.

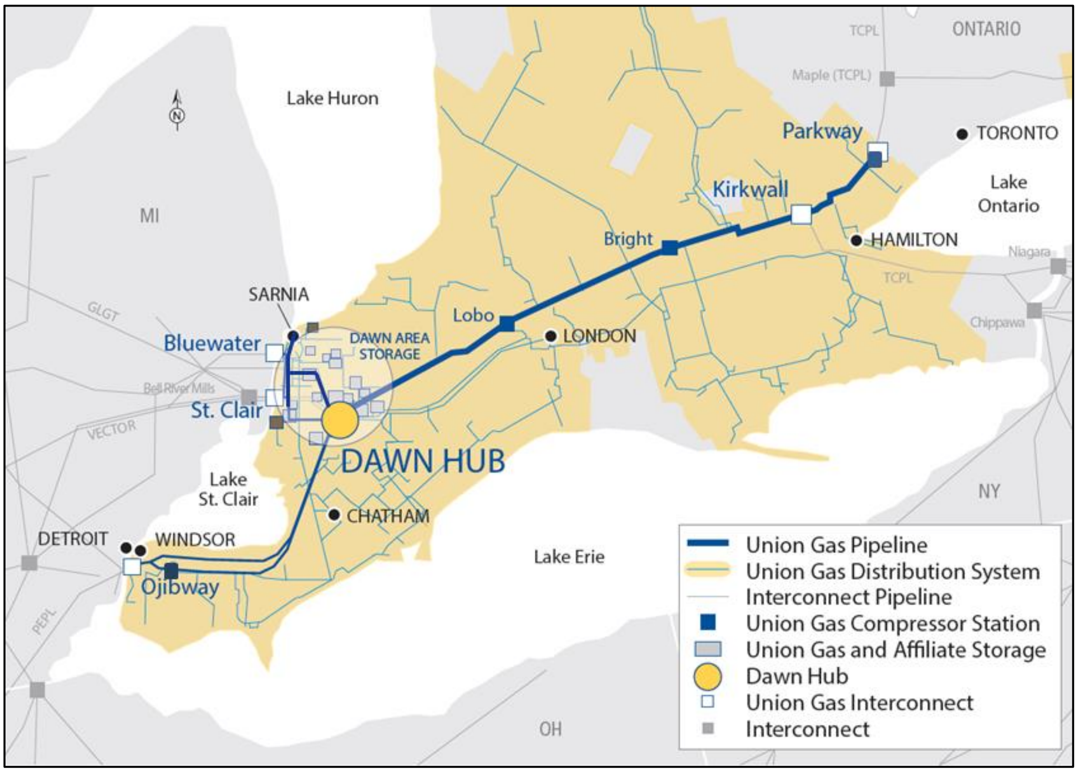


Figure 5.4.1.1.2: Panhandle, Dawn to Parkway, and Sarnia Industrial Line Systems

Union's Sarnia Industrial Line System consists of a network of pipelines ranging from NPS 8 and NPS 20, including connections to both the NPS 20 Bluewater Pipeline and the NPS 24 St. Clair Pipeline. This pipeline system serves in-franchise customers in Sarnia and St. Clair Township and ex-franchise customers via the St. Clair and Bluewater pipelines.

Union's 2,980 km of pipelines greater than 30 per cent SMYS cover a large operating area, comprised of a variety of unique operating conditions, including:

- 65 per cent of the pipelines operate at greater than 50 per cent SMYS, none are greater than 72 per cent SMYS

- 4 per cent are in Class 3 locations
- 10 per cent are in high consequence areas

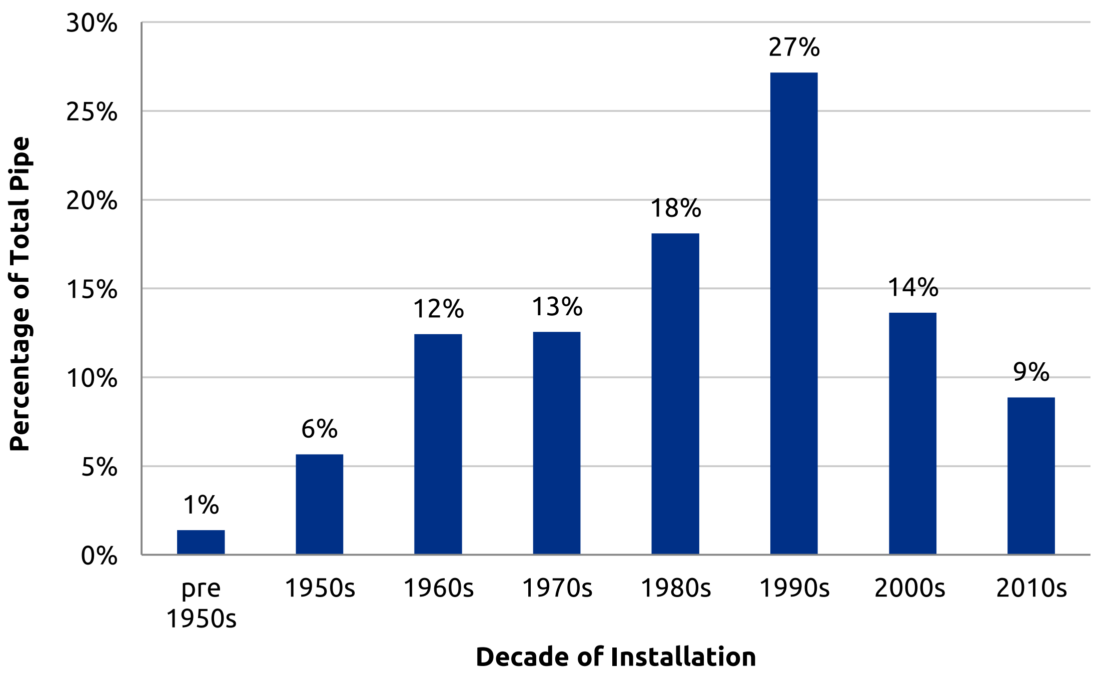
NOTE: *A Class 3 location is classified as an area (1.6 km along the pipeline) that has 46 or more buildings intended for human occupancy. A high consequence area is an area where a pipeline release would have greater consequence to health and safety or the environment.*

5.4.1.2 Overview of Pipelines less than 30 per cent SMYS

This asset class includes pipelines, services, and piping components that operate below 30 per cent of the Specified Minimum Yield Strength (SMYS). These assets are used to transport natural gas within Union's distribution systems or to end-use customers. This asset class includes 40,514 km of mains and associated valves and fittings. Of these mains, 53 per cent are plastic and more than 85 per cent operate at a pressure less than 700 kPa. This asset class also includes 1,363,000 services made up of 27,564 km of pipe and associated fittings. 72 per cent of these services are plastic and 98 per cent have an operating pressure less than 700 kPa (all values are based upon December 31, 2017 data).

Although distribution networks have been in place for over 100 years, the overall system is relatively new, as evidenced by Figure 5.4.1.2.1. Much of the older systems, particularly those that represented higher risk, have been replaced over time.

Figure 5.4.1.2.1: Percentage of total pipe by decade of installation for less than 30 per cent SMYS pipelines



5.4.1.3 Summary of Pipeline Maintenance Capital Projects

Table 5.4.1.3.1: Pipelines 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Pipeline <30% SMYS	**31.4**	**115.3**	**141.6**	**38.0**	**28.0**	**27.8**	**19.1**	**19.4**	**19.3**	**20.1**	**460.0**
Cathodic Protection	8.0	7.0	9.9	9.9	6.6	6.6	6.6	6.9	6.7	7.4	**75.4**
Bare and Unprotected steel	9.1	9.2	10.7	12.9	9.1	8.8					**59.8**
Emo Sched 10	2.8										**2.8**
Leakage	2.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	**40.6**
Service Replacement	4.3	4.4	4.5	4.6	4.7	4.7	4.8	4.9	5.0	5.1	**47.0**
General Mains	2.0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	**32.3**
Windsor Line	3.0	83.0	2.0								**88.0**
London Lines		4.0	107.0	3.0							**114.0**
Pipeline > 30% SMYS	**44.5**	**34.1**	**33.9**	**27.9**	**32.4**	**33.4**	**33.4**	**33.4**	**33.4**	**33.4**	**339.4**
Depth of Cover >30% SMYS						1.0	1.0	1.0	1.0	1.0	**5.0**
Integrity Management Program	14.6	14.1	13.9	12.9	12.4	12.4	12.4	12.4	12.4	12.4	**129.6**
Class Location	20.4	20.0	20.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**165.4**
MOP Verification					5.0	5.0	5.0	5.0	5.0	5.0	**30.0**
Bruce Lake	9.5										**9.5**
Other	**26.2**	**37.4**	**34.2**	**32.8**	**31.0**	**33.2**	**33.0**	**106.3**	**32.0**	**31.7**	**397.8**
General Pipeline Maintenance	4.4	13.4	10.2	8.8	7.0	9.2	9.0	7.3	8.0	7.7	**85.0**
Municipal Replacement	21.8	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	**237.8**
Vintage Pipeline Replacement								75.0			**75.0**
Pipelines Total	**102.1**	**186.8**	**209.7**	**98.7**	**91.4**	**94.3**	**85.4**	**159.1**	**84.6**	**85.1**	**1,197.2**

Cathodic Protection

This program includes the required expenditure to install anodes and replace aging or obsolete rectifiers in order to reduce the amount of down plant within Union's system. These installations and replacements are based on the internal Standard Operating Practice established to maintain the appropriate level of cathodic protection on steel pipeline assets.

Bare and Unprotected

This program is to replace all the bare and unprotected steel mains within Union's franchise. These mains are more susceptible to leaks as they have not been cathodically protected since installation. About 60 per cent of these mains are in in urban areas, approximately 5 per cent of which are in highly-developed areas. The remainder of these mains are in rural areas. Removing these mains from service will reduce potential for leaks due to corrosion. If this project spend is reduced or deferred, more maintenance dollars will have to be spent repairing leaks on pipe which is nearing end-of-life.

Union's 2017 customer engagement survey found that 50 per cent of those surveyed recommend prioritized replacements, while 41 per cent recommend following existing practices for replacement. The positive feedback supports Union's strategy for replacing bare and unprotected steel pipe over the next six years.

EMO Schedule 10

Union has approximately 14 km of Schedule 10 distribution main within two communities. This thin-wall pipe is very difficult to weld and requires special welding procedures. Removing this pipe from Union's system will reduce the chance of leaks due to failure of older welds.

Leakage

This expenditure accounts for the annual district capital blanket budgeted for unforeseen maintenance requirements arising from pipeline leakage identified throughout the year.

Service Replacements

This expenditure accounts for the annual district capital blanket budgeted for maintenance requirements associated with individual customer services that require replacement or repair due to their age and condition.

General Mains

This expenditure represents the annual blanket dollars required to fund maintenance work associated with distribution pipeline main that is identified with integrity-related issues that require replacement or repair.

London Lines and Windsor Lines

Both of these pipelines are nearing end-of-life and significant capital expenditures are required on a yearly basis in order to maintain these pipelines. Multi-year replacement strategies have been developed for both of these pipelines based on known risk factors. If these replacement spends are reduced or deferred, significant amounts will be required to continue to maintain these pipelines.

Depth of Cover

In compliance with the TSSA Code Adoption Document, Union has an annual depth of cover survey program for all 30 per cent SMYS pipelines. These surveys may identify locations were remediation is required. The current cycle of depth of cover surveys will be completed in 2023 at which time a prioritized list of capital replacements will be created to plan for any identified required remediation.

Pipeline Integrity Management

This expenditure is the result of the Integrity Management Program, a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of Union's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for permanent inline inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, and replacement of pipeline segments with integrity issues that are identified through the inspections.

Since the program was introduced in 2002, a number of opportunities for continual improvement have been implemented. Union has developed additional criteria and processes to inspect pipelines on a risk-based frequency that takes into account the operating characteristics and condition of the pipeline, and if its location has an impact on the potential consequence of a failure. Union also continues to retrofit some of the pipelines that were initially assessed through ECDA to accommodate ILI tools and improve the completeness of the integrity assessments. Further work has been completed to reconfigure some of the pipelines that were previously inspected with ILI tools to improve the quality of the data that is collected by the tools.

Class Location

Annual Class Location surveys are required as per the Canadian Standards Association Z662 – Oil and Gas Pipeline Systems for pipelines greater than 30 per cent SMYS. Any changes in class location need to be assessed to the current standard to determine if pipeline modifications are required. Urban development occurs in close proximity to Union's pipelines which triggers annual class location changes. An annual budget is required for Union's pipeline system in order to meet the current standard requirements which generally involves replacement of pipe segments. Remediation includes pressure testing, installation of valves, remediating depth of cover issues, and in some cases pipeline replacement. This work ensures Union is compliant and fosters the safety of the public and Union's pipeline system.

Maximum Operating Pressure (MOP) Verification

MOP verification is the process of reviewing all existing records for a pipeline system and confirming the maximum operating pressure of existing greater than 30 per cent SMYS pipeline systems based upon these records. While this is not currently mandated by code in Canada, it is required in the U.S. and is expected to become a requirement in

Canada in the future. Given Union has approximately 2,980 km of pipelines greater than 30 per cent SMYS, MOP Verification will be a multi-year project requiring a dedicated team to complete the verifications and determine if any pipeline remediation is required. This forecast includes the costs of replacing sections of pipelines as identified through the MOP verification work. MOP verification was also included in the 2017 customer engagement survey: while 43 per cent of those surveyed recommend waiting for regulation requirements to keep costs down, 40 per cent recommend proactively implementing industry standard. Spreading the verifications over several years will keep costs down and proactively implement an industry standard, which provides additional support for this program. Starting this program as forecast will mitigate the need for higher expenditures in a shorter time frame to meet these expected future mandated requirements.

Bruce Lake

The Bruce Lake/Ear Falls Lateral needs to be operated at an elevated pressure to maintain Union's system. Union has completed a detailed engineering review to validate the condition of this system prior to increasing the pressure on this lateral, which includes making the pipeline piggable, completing an inline inspection, and taking the line out of service to complete a pressure test. Deferring or reducing spend on this project will create risk of potential customer loss during high demand periods.

General Pipeline Maintenance

The capital expenditure included in this category covers a variety of planned maintenance projects. The projects covered under this expenditure include low pressure system replacements, distribution pipeline replacements due to historical leakage and integrity concerns, pipeline casing replacements, bridge and water crossing replacements and repairs etc. These projects are often identified through planned inspections and pipeline surveys and would then be assessed and planned based on risk and resource availability.

Municipal Replacement

Projects in this category are capital expenditures required to replace or relocate segments of pipeline in order to accommodate municipal infrastructure work. The cost sharing for this work is managed through the Franchise Agreements established with municipalities. A consultative approach is used between the municipality and Union to avoid conflicts with municipal infrastructure early in the planning stage. If a conflict is unavoidable, Union's pipeline assets are typically relocated or replaced.

Vintage Pipeline Replacement

The capital identified in this category is a placeholder for a future major pipeline replacement. Similar to the Windsor and London Lines projects, Union expects to have another major replacement project in the next 10 years. Ongoing condition and integrity assessments are expected to identify pipelines that will elevate in risk in the future that will drive a more detailed plan for replacement.

5.4.1.4 Summary of Pipeline Incremental Operations and Maintenance (O&M)

Table 5.4.1.4.1: Pipelines 10-Year Forecast of Incremental O&M (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
MOP Verification		1.6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Class Location		-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Pipeline Integrity	0.5	3.7	3.2	2.9	2.3	2.1	2.1	2.1	2.2	2.2
Easement Clearing	0.3	0.5	0.6	0.6	0.3	0.3	0.3	0.3	0.3	0.3
Pipeline Incremental O&M Total	**0.8**	**5.7**	**6.1**	**5.8**	**4.9**	**4.7**	**4.7**	**4.7**	**4.9**	**4.9**

Maximum Operating Pressure (MOP) Verification

The MOP verification project is incremental work that will require incremental resources to complete. These resources will be tasked with completing records reviews and engineering assessments in order to validate the maximum operating pressures (MOPs) of Union's greater than 30 per cent Specified Minimum Yield Strength (SMYS) pipelines. In instances of insufficient records, validation digs may be required to determine potential remediation requirements, which is also part of this additional spend.

Class Location

The expenditure included in this program funds Engineering Assessments that are used to address changes in class location of Union's 30 per cent SMYS pipelines as an alternative to Pipeline replacement. The forecasted reduction reflects the expectation that Union will be moving into sustainment with respect to the Class Location program and that the number of identified Class Location changes should be declining.

Pipeline Integrity

This portfolio includes an increase to further the Pipeline Integrity Management Program in terms of External Corrosion Direct Assessment (ECDA) inspections, assessments for stress corrosion cracking, and increased inline inspection (ILI) inspection frequency requirements. Also included in this expenditure are additional programs related to distribution integrity, most notably the additional expenditure required for the inspection of water crossings and bridge crossings.

Easement Clearing

The historical spend with respect to Easement Clearing has been reviewed and is determined to be inadequate to maintain clear easements for Union's existing pipelines and the incremental addition of new pipelines and associated easements. The identified incremental funds will assist in accelerating Union's Easement Clearing program and add focus to this work.

5.4.2 System & Customer Stations

5.4.2.1 Overview of System Stations

System stations are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.

System station components consist of piping, meters, regulators, valves, filters, separators, heaters, odourant, controls, and in some cases, structures. System station components can vary greatly depending on the station's application and design complexity. At Union, system stations are broken down into subclasses which drive design and operating practices as well as inspection requirements. A summary of the system station subclasses can be found in Table 5.4.2.2.1.

5.4.2.2 Overview of Customer Stations

Customer Stations, similar to System Stations, are designed to deliver a specific volume of natural gas at a reduced delivery pressure from natural gas pipelines as requested and/or required by individual customers for end-use consumption.

Typical delivery pressures can vary from 1.75 kPa to 1,380 kPa or higher depending on individual customer needs. The pressure and volume requirements for customers are driven by the customers' natural-gas-fired equipment requirements.

Typical components of customer stations can vary greatly based on the size and operating requirements of a particular customer. The smallest of customer stations (meter sets) are typically composed of small diameter piping, a single regulator and meter, and a single shut off valve. Larger customer stations can be composed of filter/separators, multiple regulators and meters, large diameter piping and headers, electrical, controls and telemetry, natural gas heating, odourant injection systems, and multiple valves. Customer stations are broken down into subclasses which drive design and operating practices as well as inspection requirements. A summary of customer station subclasses can be found in Table 5.4.2.2.1.

Union's largest in-franchise customer station facilities typically supply natural gas to major electric power producers. The subclass A customer stations also feed natural gas to major steel mills, chemical plants, smelters, and other process based industrial plants.

Table 5.4.2.2.1: Inventory of System and Customer Stations

Station Subclass	Operating Parameters		Systems Station Inventory	Customer Station Inventory
	Maximum Inlet Pressure	Inlet Size		
Subclass A	Over 3,450 kPa	NPS 3 and over	280	100
	Any Pressure	NPS 8 and over		
Subclass B	Over 3,450 kPa	NPS 2	770	1,500
	3,450 kPa and Under	NPS 3 to NPS 6		
Subclass C	3,450 kPa and Under	NPS 2	1,930	11,800
	All Pressures	Less than NPS 2		
Residential	All	All		1,382,500
		Total Number of Stations	2,980	1,395,900

5.4.2.3 Summary of System and Customer Stations Maintenance Capital Projects

Table 5.4.2.3.1: System and Customer Stations 10 Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Obsolete Heating Equipment	1.8	4.1	4.6	0.7	0.7	3.7	2.1	0.9	1.4	1.9	**21.8**
Hamilton Gate	2.0										**2.0**
Regulators/Reliefs		9.1	8.9	8.9	9.2	9.2	9.1	9.0	8.8	8.8	**81.0**
Replacement of Vaulted Stations		1.6	3.5	1.6	1.5	1.5	0.7				**10.4**
Station Painting	1.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	**19.5**
Stations Capital Maintenance	1.2	6.7	3.0	3.0	2.7	4.0	3.6	5.9	5.1	2.5	**37.8**
Frost Heave		0.9	0.6	0.1	0.5	2.5	1.4	2.0	0.4	0.1	**8.5**
Stations Total	**6.5**	**24.3**	**22.6**	**16.2**	**16.6**	**22.8**	**19.0**	**19.9**	**17.7**	**15.4**	**181.0**

Obsolete Heating Equipment

Natural gas heating equipment is used in many system and customer stations across the Union franchise to help mitigate failure of equipment due to the freezing of liquids in the gas stream as well as moisture that surrounds buried piping. Over Union's many years of operation, a variety of heating systems have been used resulting in many variations of equipment age, and the introduction of equipment obsolescence. This project includes ongoing maintenance to replace equipment that has reached end-of-life or has been deemed obsolete. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills. This forecast will improve efficiency in operating costs of aging systems and will mitigate the risk of equipment failures that could result in loss of customers and/or loss of glycol containment.

Hamilton Gate

Maintenance activities will be required for Hamilton Gate Station in 2019 in order for it to operate safely and reliably until the station is rebuilt in 2021. These maintenance activities include: boiler system upgrades at Hamilton Gate Station 2 due to current failure, replacement of steel access platforms to the heat exchangers, and engineering assessments of the building, piping and heat exchanger to support the 2021 to 2022 project.

Regulators/Reliefs

This capital spend represents the year-over-year cost of purchasing and stocking of natural gas regulators and relief valves to support ongoing maintenance work. As regulators and relief valves fail or require replacement due to age or obsolescence, (whether it be at the time of meter exchange or in conjunction with other maintenance projects) regulators are purchased and stocked for field representatives and technicians so that they can maintain the high reliability of Union's system and customer stations. This forecast will mitigate shortages of equipment so that services to customers are maintained.

Replacement of Vaulted Stations

Union's system station assets include a number of below grade vaulted stations. This project will replace all remaining vaulted stations with above grade facilities, reducing the risk of equipment failure and ensuring the reliability and integrity of these sites. These stations are advanced in age and present significant maintenance challenges due to their confined nature and a variety of risks with respect to asset deterioration and equipment failure. The vault design is prone to water ingress that can cause frost heave, accelerated corrosion of the assets and the vault itself, and can interfere with the proper operation of equipment. All of these factors have a negative effect on reliability and can create personal injury risks. As the solutions for each asset are developed, customer engagement results will be leveraged to select either a typical system station design with land purchase or an above grade enclosure station where land purchase is impractical. This forecast will decrease risk of equipment failure, improve system reliability and result in the stations being more safely and efficiently maintained.

Stations Painting Program

This is a centrally managed program to apply high performance paint to stations where existing paint has begun to fail or wear off of the facilities on which it has been applied. The station painting program is a significant corrosion mitigation practice. The frequency and criteria for high performance painting at station sites is specifically prescribed in Union's Corrosion Control Standard Operating Practice (SOP) and is its documented and committed practice with respect to how we comply with the applicable codes for corrosion control on above grade station assets. This work will improve compliance and ensure the safety and reliability of Union's assets by reducing the risk of leaks and piping and/or equipment failure due to significant corrosion.

Stations Capital Maintenance

This category includes a number of risk remediation programs and general maintenance activities that are part of the core system and customer station maintenance work at Union:

- Obsolete equipment - As station facilities age, regulators and relief valves can become obsolete due to vendors no longer supporting specific types of equipment or simply that they have aged and created maintenance and reliability concerns. This project is an effort to remediate all currently identified obsolete equipment from

Union's system. The allocated cost is for installation and fabrication time; equipment cost is covered in the regulator/relief valve line item. This program will build on system reliability and generate field efficiencies due to reduced variability of equipment found in the field and simplified maintenance.

- Regulator Freeze offs - As natural gas supplies into the pipeline systems change, natural gas quality can also change. Existing system stations that experience significant pressure cuts combined with elevated moisture content in the natural gas stream can cause freezing of regulators and loss of downstream customers. Sites of concern will continue to be addressed as needed.
- Station Blankets - Spend is also allocated to each region to ensure they have capital available for unforeseen maintenance challenges. These challenges can be leaks or failures that require short turnaround times for remediation, particularly if there has not been a specific project identified for affected assets.

Frost Heave

Stresses imparted on station facilities due to frost formation in below grade soil are targeted for remediation in some cases. This can include the addition of station heaters or simply the excavation and leveling of station sites where heaving is less severe. This work ensures the risk of leaks and piping failures are reduced and therefore system reliability is maintained. This also ensures Union workers are not subjected to maintenance challenges where piping can spring out of place due to the stresses imparted from frost heave.

This forecast will improve system reliability and help ensure continued service to Union's customers.

5.4.2.4 Summary of Stations Incremental Operations and Maintenance

Table 5.4.2.4.1: Stations 10-Year Forecast of Incremental O&M (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations Integrity		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

The primary driver for increased O&M activity in the stations category is for integrity assessment and mitigation of station piping and components.

5.4.3 Measurement

Measurement assets include a fully integrated family of devices that allow safe operation of the natural gas network, provide accurate and timely measurement, and monitor and control the flow of natural gas in real time. Measurement assets include the following subclasses:

- Natural Gas Meters.
- Electronic Volume Correctors.
- Odourization Systems.
- Gas Monitoring and Control Systems.

5.4.3.1 Natural Gas Meters

Natural gas meters are devices used in measuring the quantity of natural gas delivered. Meters can be further classified as custody transfer or non-custody transfer. The former are billing meters for gas purchased from suppliers or sold to customers and as such must meet the legal requirements of the Electricity and Gas Inspection Act. The latter are used for internal accounting of gas inventories.

Union uses a variety of gas meter types to fit different applications and requirements as outlined below.

Diaphragm Meters

Diaphragm meters use positive displacement technology and internal mechanical temperature compensation to calculate delivered natural gas volumes at base temperature and pressure.

The 200 class meter is the most common meter type in use. The 400 class meters are used for commercial and large residential loads and have incrementally more capacity than a 200 class. The 800/1000 class meters are used for large commercial, small industrial and estate residential loads.

Commercial Ultrasonic Meters

Commercial ultrasonic meters are used as a direct substitution for 800/1000 class diaphragm meters. They use inferential ultrasonic flow measurement and electronic temperature correction and consumption recording.

Rotary Meters

Rotary meters are positive displacement devices comprised of a meter body coupled with an electronic volume corrector. The two styles of rotary meters are temperature compensated and instrument drive. Rotary meters are used in commercial and industrial applications.

Turbine Meters

Large Turbine meters are inferential metering devices used at large commercial and industrial customer stations for high-volume metering. They are also used for volumetric measurement at interconnect sites between Union and other pipeline companies.

Large Ultrasonic Meters

Large ultrasonic meters are sophisticated multi-path inferential measurement devices directly connected to remote terminal units (RTUs) for measurement of large volumes of gas at high pressures.

5.4.3.2 Electronic Volume Correctors

Rotary Temperature Compensated Modules

Rotary temperature compensation modules are directly attached to temperature compensated rotary meters. They correct meter volume to standard conditions based on temperature recorded at the meter.

Electronic Volume Integrators

Electronic volume integrators are directly attached to instrument drive rotary meters and turbine meters. They correct volume to standard conditions based on temperature and pressure recorded at the meter.

Automated Meter Reading (AMR)

AMR devices are installed on diaphragm, commercial ultrasonic, and temperature compensated rotary meters. These devices record and store meter consumption data after being corrected to standard units. They then transmit this information wirelessly to meter reading devices that upload the consumption to Union's billing system.

5.4.3.3 Odourization Systems

Natural gas in its basic state is virtually odourless and can be difficult to detect if accidently released to the atmosphere. To protect the public and operate assets safely, natural gas is odourized at major stations to make it easier to detect as required by Canadian Standards Association Z662 – Oil and Gas Pipeline Systems.

5.4.3.4 Gas Monitoring and Control Systems

The natural gas monitoring and control system is comprised of field equipment for the Supervisory Control and Data Acquisition (SCADA) System for monitoring and control of natural gas flow and odourizing natural gas at large stations, custody measurement, and control of critical valves. This system is crucial to providing live natural gas measurement and operational information to various stakeholders.

The natural gas monitoring and control system is made up of Remote Terminal Units (RTUs - Bristol 3330/3310), which were installed from 1989 to 2006, with the majority installed between 1995 and 1999 in locations across Union's entire franchise. Communication devices are also included (satellite/cellular/radio modems), which were upgraded from 2008 and 2010 and again from 2015 to 2019 in locations across Union's entire franchise.

5.4.3.5 Asset Inventory Statistics and Geographic Locations

The following table summarizes information about asset classes, major components, and their inventory.

Table 5.4.3.5.1: Measurement Assets and Inventories

Measurement Asset Subclass	Device Type & Inventory
Natural Gas Meters	• Diaphragm meters (1.4 million) • Rotary meters (17,506) • Turbine meters (600) • Ultrasonic meters - commercial (7,850) and interconnects (80)
Electronic Volume Correctors	• Electronic rotary modules (16,023) • Electronic Volume Integrators (2,208) • AMR Devices (80,057)
Odourization Systems (Bypass & Injection)	• MOIS injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)
Natural Gas Monitoring & Control Systems	• RTU (400) • Communication equipment(cellular, satellite, radio) – (300) • Transmitters (1,500) • Power supplies etc.

5.4.3.6 Summary of Measurement Maintenance Capital Projects

Table 5.4.3.6.1: Measurement 10 Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Meter Exchange Program	34.8	30.2	30.6	30.8	31.8	32.0	32.3	33.4	33.6	33.8	**323.2**
Measurement Electronics Upgrades	0.2	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	**2.6**
Obsolete RTU Equipment	1.4	3.1	3.1	2.5	2.0	2.0	2.0	2.0	2.0	2.0	**22.2**
Odourant Upgrades	1.0	1.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0	**9.6**
Measurement Total	**37.4**	**34.9**	**35.0**	**34.7**	**35.2**	**35.3**	**35.6**	**36.6**	**36.9**	**36.1**	**357.6**

Meter Exchange Program

This program will remove meters and replace them with new meters as required to comply with the legal requirements of Measurement Canada. Batches of diaphragm meters are removed each year and tested to ensure the population of meters in the field meet regulatory requirements. Smaller meters are compliance-tested to meet regulatory requirements. Larger meters (rotary and turbine meters) and Electronic Valve Integrators (EVIs) are condition-tested in service to confirm adequate performance levels. If they do not meet adequate performance levels they are then removed, re-verified and returned to service.

The Meter Exchange Program budget forecast includes the procurement of all types of replacement meters, electronic volume correctors, AMR, regulators for 200/400 series replacement meters and labour cost of 200/400 series replacement meters.

The number of meter exchanges required beginning in 2019 is shown below. These exchange requirements are expected to continually grow as the overall in service population continues to grow.

- 200 series diaphragm meters – 54,402 exchanges.
- 400 series diaphragm meters – 4,851 exchanges.

Measurement Electronics Upgrades

This portfolio includes low-budget, small-scale capital projects to sustain and enhance operational support. These projects include Auto-Oilers, Turbo Correctors (TOC), lab upgrades, technician tools, industrial billing modems upgrades, billing communication modem lifecycle, and measurement replacement at low flow odourant sites. The benefit of these projects will be smooth and reliable operation.

Obsolete Equipment/SCADA RTU Lifecycle

The forecast in this category includes projects to replace all the existing remote terminal units and replace with current technology, the ControlWave Micro introduced in 2003. Many current Remote Telemetry Units (RTUs) are 3330/3310 which have been obsolete since 2009 and are no longer supported by the manufacturer. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU lifecycle project will take over as the current technology will be 21 years old. The benefit of these projects will be smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at end-of-life and deferring this work may increase failure rate drastically due to the “wear-out” effect.

Odourant Upgrades

The expenditures in this portfolio include projects to upgrade odourant systems to ensure compliance to current codes, such as replacing old tanks and painting rusted containment pans and tank stands. Additionally, performance capability will be added by installing heat tracer lines, heated cabinets, improved tank valves and indoor regulator panels. This work will help to ensure safe, compliant and continuous odourization. This forecast will help mitigate the risk of tank rupture, frequent freeze off and nuisance odour calls.

5.4.3.7 Summary of Measurement Incremental O&M

Table 5.4.3.7.1: Measurement 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Meter Accreditation Internal Audit	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Increased O&M in this portfolio is due to increased requirements for internal audit of the Measurement Accreditation Program. As of 2019, Enbridge will no longer be providing Internal Audit Services of the Measurement Accreditation Program. It is a legal requirement to conduct an internal audit as per the Measurement Accreditation Standard. Union is currently seeking potential external service providers with the necessary experience for 2019.

5.4.4 Utilization

This asset class consists of the pipes, fittings, and equipment located downstream of the meter. As the components of this asset class are not owned by Union, the decisions about additions, maintenance and renewal are not made by Union and are not a part of this report. As the supplier of natural gas, Union plays a part in ensuring these systems are safe through inspections during customer visits. Union has a statutory obligation to inspect customer-owned equipment at the time of initial activation and when natural gas supply is interrupted for any reason as per the Ontario Regulation 212/01 Gaseous Fuels.

5.4.5 Underground Storage

The use of subsurface facilities for natural gas storage allows for increased efficiency in operations, conservation of produced natural gas, and more effective and economic delivery to markets. The facilities are usually natural geological reservoirs such as depleted oil or natural gas fields sealed on the top by an impermeable cap rock.

Natural gas demand for Union's in-franchise and ex-franchise customers varies seasonally and is greatly affected by residential heating requirements. Underground storage provides seasonal balancing for the gas supply capability versus demand requirements of Union's customers.

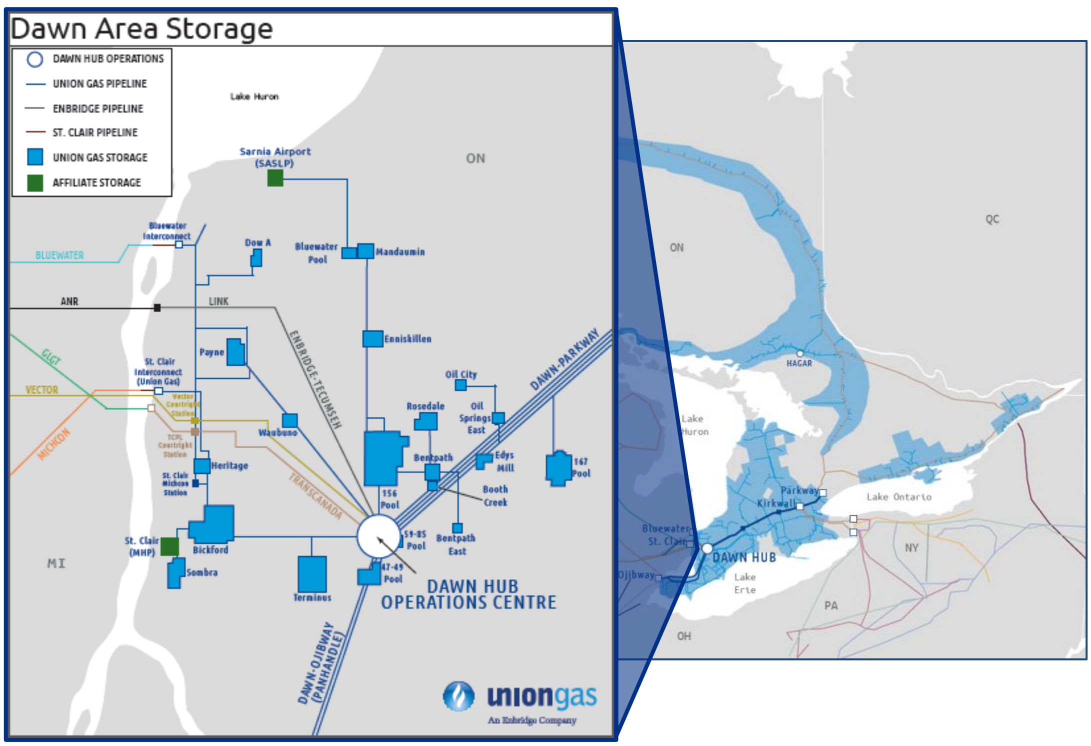


Figure 5.4.5.1.: Natural Gas storage pools (Lambton County)

Union (including Union Affiliates) stores natural gas in 23 company-owned storage reservoirs and four third party storage reservoirs. The storage capability of each reservoir is determined by the reservoir's maximum operating pressure, the cushion pressure, and the size of the pool. Capacities in the 23 storage reservoirs range from 31,000 10^3m^3 (1.2 PJ) to 830,800 10^3m^3 (32.0 PJ). Through Union's reservoirs, Union has a storage capacity of 4,744,500, 10^3m^3 (185 PJ) with cushion natural gas totaling 1,665,000 10^3m^3 (64 PJ).

Each reservoir is protected by a Designated Storage Area (DSA) as determined by the Ontario Energy Board (Board) to protect the reservoir from exploratory drilling. The land above each reservoir is leased from the landowners with storage leases. There are currently over 10,000 acres leased by Union for storage.

There are a total of 230 wells (as of September 2018) operated by Union to support the movement of natural gas into and out of the underground reservoirs. The 230 wells include 166 injection withdrawal wells, 63 observation wells, and one maintenance well.

5.4.5.1 Summary of Storage Maintenance Capital Projects

Table 5.4.5.1.1: Underground Storage 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Storage Improvements	0.4	1.9		1.2	1.3	1.3	0.7	0.4	0.4	0.4	**9.2**
Storage Integrity	0.3	0.3	0.3	0.3	0.3	2.3	0.3	2.4	0.3	2.4	**8.7**
Underground Storage Total	**0.6**	**2.1**	**1.4**	**1.4**	**1.5**	**3.5**	**1.0**	**2.8**	**0.7**	**2.8**	**17.9**

Storage Improvements

These projects will improve the performance, condition and safety of the storage wells. The following are examples of storage improvement projects:

- Well testing to identify and remediate wells that have lost deliverability through ongoing operation.
- The installation of emergency shutdown valves on storage wells to provide the ability to remotely isolate each well.
- A wellhead pressure and flow monitoring project to identify flow restrictions, interference between flowing wells, and identify deliverability losses with the goal of maintaining and improving Union’s total system deliverability.

Storage Integrity

Casing inspection logs are completed on a prescribed basis as per Canadian Standards Association Z341 Storage of Hydrocarbons in Underground Formations. The storage integrity projects include remediation requirements as a result of the casing inspection log. The remediation may include additional testing, well relining, repair or well abandonment. In some cases, additional wells may be required to replace the lost well deliverability as a result of the remediation.

5.4.5.2 Summary of Storage Incremental Operations and Maintenance

Table 5.4.5.2.1: Underground Storage Incremental O&M (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Well Maintenance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Increased O&M activity in the underground storage category is due to an increase in the casing inspection log survey that is required by code. The increase in logging expenditure is due to the following reasons:

- New requirements for cathodic protection profile logs.
- Additional wells.
- Labour and contractor price increase.

5.4.6 Compression and Dehydration

Union uses compressors to move natural gas throughout the natural gas transmission system by compressing natural gas into transmission pipelines designed for high flow. Compressors are also used to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow.

Dehydration facilities are also included in the compression asset category. Dehydration facilities remove moisture from natural gas to ensure that the natural gas entering the transmission system meets the contractual standard of moisture content, and to avoid operational problems related to high moisture content. The dehydration process involves contact between the natural gas stream and liquid glycol stream to remove excessive moisture from the natural gas stream. The resultant output natural gas that ensures pipelines are dry and customer quality for moisture content are met.

Union's main compressors are located at the Dawn Compressor Station, the site of the largest underground storage facility in Canada and a key natural gas trading hub. The Dawn Hub has interconnections to 10 major transmission pipeline systems including Vector, TransCanada Pipelines, Tecumseh Gas Storage, and Panhandle Eastern through the Union Panhandle Transmission system. The Dawn Compressor Station consists of nine compressors with a combined total of 252,350 ISO horsepower, a major natural gas dehydration plant and associated piping, large diameter valves, electrical components and other equipment required to support the operation of this station.

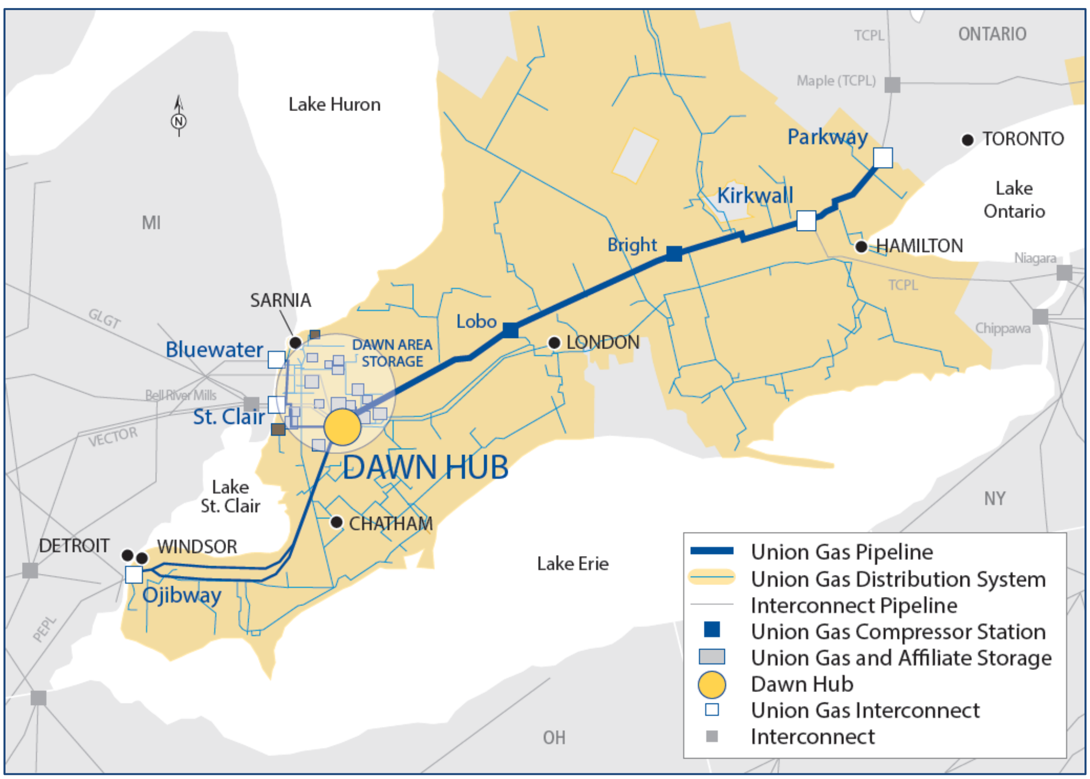


Figure 5.4.6.1.: Overview of Union's storage and transmission system, showing major compressor plants

There are four major compressor stations located along the Dawn to Parkway System located at Lobo, Bright, Parkway West, and Parkway East and can be seen in Figure 5.4.6.1. These stations consist of a total of 13 compressors with a combined total of 478,790 ISO horsepower.

Union maintains loss of critical unit coverage at Dawn and at the compressor stations located along the Dawn to Parkway System. Loss of critical unit coverage is required to provide compression to continue to provide services to customers if an unplanned compressor outage of a compressor that would create the greatest loss of system capacity if it failed on a design day.

Union has many other compressor stations located within the franchise including compressors located at underground storage facilities and in remote geographic areas.

Table 5.4.6.1: Compression Inventory

Location	Inventory	General Notes
Dawn Compressor Station	9 Compressors 1 Dehydration plant	Interconnects with pipelines from a number of other companies and Union's storage system. Provides supply to the Union transmission systems and loss of critical unit coverage for the Dawn Parkway System.
Lobo Compressor Station	5 compressors	Supports gas transmission from London towards Woodstock on the Dawn-Parkway system. It includes the current loss of critical unit coverage for the Dawn Parkway System.
Bright Compressor Station	4 compressors	Supports gas transmission from Woodstock towards Toronto (Parkway) on the Dawn-Parkway system.
Parkway Compressor Station	2 compressors	Acts as a custody transfer station to Enbridge and TransCanada Pipelines and provides required delivery pressure to TCPL.
Parkway West Compressor Station	2 compressors	Acts as custody transfer station to Enbridge and TransCanada Pipelines and provides required delivery pressure to TCPL as well as loss of critical unit compressor for Parkway.
Sandwich Compressor Station	1 compressor	Supports movement of gas from the Panhandle Eastern Pipeline system towards Dawn.
Hagar Liquefied Natural Gas Station	2 compressors	Supports the Sudbury System during peak periods, provides additional compression as required to maintain pressure.
Iroquois Falls Compressor Station	1 compressor	Supports required delivery pressure for industrial plant in Iroquois Falls.

Location	Inventory	General Notes
Remote Storage Pool Compressor Stations	14 compressors	Supports storage facilities.

5.4.6.1 Summary of Compression and Maintenance Capital Projects

Table 5.4.6.1.1: Compression 10 Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Compressor Overhauls		1.9		0.4	8.9	1.9	2.4	6.4	1.0	2.5	**25.5**
Compressor Upgrade - Replace Plant C				19.3	82.9	48.7	5.0				**155.9**
Compressor Upgrade - Replace Waubuno		3.2	15.2								**18.3**
Compressor and Dehy Capital Maintenance	2.2	3.1	2.1	0.9	0.9	0.9	2.0	6.9	1.3	5.6	**25.9**
MSAPR Emissions Action Plan	0.2	0.2	0.2	0.1	0.1						**0.9**
Station Painting	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	**7.0**
Compression Total	**3.1**	**9.0**	**18.2**	**21.4**	**93.5**	**52.2**	**10.3**	**14.0**	**3.1**	**8.9**	**233.7**

Compressor Overhauls

These projects consist of the Original Equipment Manufacturer (OEM) prescribed scheduled maintenance/overhauls (engines, power turbines, and compressors). The overhauls satisfy the OEM recommendations to maintain equipment reliability. The project includes full internal inspections and replacement of wear items to maintain reliability and reduce the risk of failure. These projects ensure continued asset and system reliability. If the OEM recommended maintenance intervals are exceeded, the risk of reduced reliability and performance increases.

Compressor Upgrade – Replace Plant C

This project is the replacement of Dawn C Plant due to the obsolescence of a second-generation RB211-24A compressor unit that was installed in the early 1980s. The manufacturer has indicated the unit will be obsolete and no longer supported when it reaches an age of about 40 years. This means that parts and components required to support the ongoing operation of the unit may no longer be available. Union has experienced the unavailability of parts with a similar unit that has reached an age of obsolescence and was retired in 2017. Replacement of this unit in 2023 will reduce the risk of a long-term outage due to a failure and the related system reliability impacts.

Compressor Upgrade – Replace Waubuno

This project will replace the aging storage compressor at the Waubuno Station. This unit is used to inject natural gas into the Waubuno Storage Pool. The asset is over 30 years old and is becoming challenging to maintain due to difficulties sourcing replacement parts and uncertain manufacturer support. In order to ensure a reliable storage and withdrawal service, this unit will need to be replaced to avoid a significant outage.

Compressor and Dehydration Capital Maintenance

These projects consist of various compressor and Dehydration asset class replacements. These projects include replacement of uninterruptable power supply (UPS) battery banks with a finite life, light-emitting diode (LED) lighting upgrades as existing lighting ballasts fail. This forecast will improve system integrity and reliability.

Multi-Sector Air Pollutants Regulations (MSAPR)

The Multi-Sector Air Pollutants Regulations (MSAPR) came into effect in 2017. These regulations, enacted by the Ministry of Environment, Conservation and Parks Environment and Climate Change Canada (MECP) are dedicated to limiting nitrogen oxide emissions (NOx) from specific industries and equipment across Canada. Part two of the regulations are focused on stationary-spark-ignition gaseous-fuel-fired engines greater than 250k w, which specifically impacts large stationary reciprocating engines at STO. Environment, Health and Safety (EH&S) in conjunction with expert consultation and STO Engineering have developed a plan to review and address the emission exceedances. Emission allowances consider NOx emission from a fleet wide perspective and are broken into two compliance Phases.

MSAPR Phase One compliance date of Jan. 1, 2021:

- 2019
  - Dow A Compressor– install catalytic convertor - $110,000
  - Edy’s Mills Compressor – install catalytic convertor – $110,000
- 2020
  - Dawn Aux 3 Generator – install catalytic convertor - $110,000
  - Dawn Aux 4-1 Generator – install catalytic convertor - $110,000

MSAPR Phase Two compliance date of Jan. 1, 2025:

- 2021
  - Oil Springs East Unit 1 Compressor – install catalytic convertor - $110,000
  - Oil Springs East Unit 2 Compressor – install catalytic convertor - $110,000
- 2022
  - 167 Compressor – install catalytic convertor - $110,000
- 2023
  - Dawn Aux 4-2 Generator – install catalytic convertor - $110,000

Station Painting Program

This is a centrally managed program to apply high performance paint to stations where existing paint has begun to fail or wear off of the facilities on which it has been applied. The station painting program is a significant corrosion mitigation practice. The frequency and criteria for high performance painting at station sites is specifically prescribed in Union's Corrosion Control SOP and is the documented and committed practice with respect to how it complies with the applicable codes for corrosion control on above grade station assets. The benefit of this work is primarily the safety and reliability of Union's assets and ensuring code compliance. This forecast will improve compliance and reduce the risk of leaks and piping and/or equipment failure due to significant corrosion.

5.4.6.2 Summary of Compression and Dehydration Incremental Operations and Maintenance

Table 5.4.6.2.1: Compression 10 Year Forecast of Incremental O&M for (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Catalytic Converters	0.1	0.1	0.1	0.1						
Emissions Testing	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lubricants Sampling	0.2	0.4	0.4	0.4	0.1	0.1	0.1	0.1	0.1	0.1
Utilities	0.4	0.6	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Direct Leak Inspection Program	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Compression Incremental O&M Total	**0.8**	**1.3**	**1.6**	**1.8**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**

Catalytic Converters

Replace existing spent catalytic convertors plus annual maintenance.

Emissions Testing

Complete the annual greenhouse gas (GHG) emissions testing at compressor stations and Multi Sector Air Pollution stack emissions testing of the designated reciprocating engines.

Lubricants Sampling

Complete the annual engine lubrication and glycol maintenance program and increased lubricants sampling requirements to further enhance system reliability through better understanding of asset condition.

Utilities

Costs associated with power consumption are increasing due to changes in the power rates framework. Hydro assumption of 5 per cent increase annually in excess of inflation.

Direct Leak Inspection Program Requirements

The Federal methane regulations requiring direct leak inspections at compressor stations are changing and will require compressor stations be scanned three times per year going starting in 2019 and have prescribed timeframe requirements for leak repair. The default time to repair any leak that is identified is 90 days. There are, however, exceptions that may be granted under circumstances in which the volume of gas that must be vented from the pipeline in order to safely repair the leak exceeds the volume that will be saved by repairing the leak. In these cases, the leaks will be carried and tracked with maintenance work orders, until such time as the plant is shut down and the pipe evacuated for other necessary maintenance or construction activities.

In this way, the environmental impacts as well as the cost impacts are optimized. The cost to scan the compressor fleet is estimated at $110,000 based on the 2017 and 2018 work. With the recent change and the increased inspection interval to three times per year the estimated cost for this program is $330,000. There will also be a nominal increase in O&M leak repair to meet the prescribed repair timeframe considering repair timeframes may require the work to be planned and scheduled as standalone work as opposed to the historical practice of identifying and repairing leaks during plant shutdowns.

The incremental O&M forecast is to provide day to day maintenance and support of new compressor assets.

5.4.7 Liquefied Natural Gas (LNG)

Union operates one LNG facility, Hagar, located near Sudbury, Ontario, which has been in operation since 1968. Hagar is interconnected with Union's Sudbury Lateral System, which is within the TransCanada Pipeline delivery area known as Union Northern Delivery Area.

As an integrated storage and transmission system operator, Union requires the capacity to support the integrity of the system as a whole and the provision of service to all customers. This liquefied natural gas storage facility provides reserve capacity that allows for the operational balance necessary and ensures reliable supply through Union's Storage, Transmission, and Distribution systems during peak periods.

Hagar is used to support the Sudbury area during peak periods, supply shortfalls, and unplanned pressure drops or outages. As an example, Hagar was used for this purpose in 2011 when TransCanada Pipelines experienced a pipeline rupture near Beardmore, Ontario.

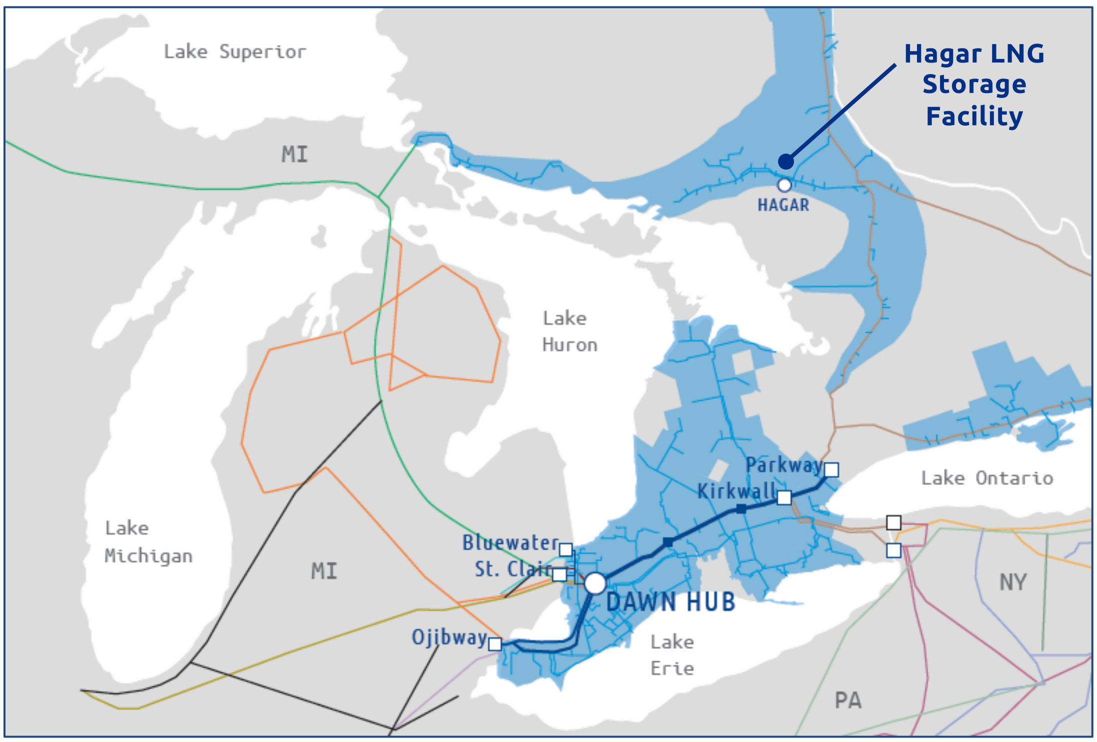


Figure 5.4.7.1: Hagar LNG Plant Location

5.4.7.1 Summary of LNG Maintenance Capital Projects

Table 5.4.7.1.1: Liquefied Natural Gas (LNG) 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
LNG Capital Maintenance				6.2	0.1	2.1	6.4		0.5	2.4	**17.7**

These projects consist of improvements to the Hagar plant which are mainly required due to its age (1968 vintage). The upgrades will improve system integrity and reliability by reducing risk due to age and prepare for potential increased production demands.

5.4.8 Supporting Assets

This grouping of assets includes Service Facilities, Fleet and Technology and Information Services (TIS).

5.4.8.1 Service Facilities

Union's Corporate Real Estate Services (CRES) group manages (operation, maintenance and improvement) owned and leased facilities along with the furnishings within, in addition to owned parcels of land. In total, the CRES portfolio includes 74 properties, 1,245,291 square feet of building space and approximately 12,000 pieces of workspace furnishings. Union's Storage and Transmission Operations (STO) group manages eight additional facilities at three properties that are not part of the CRES portfolio, for a total of 82 properties.

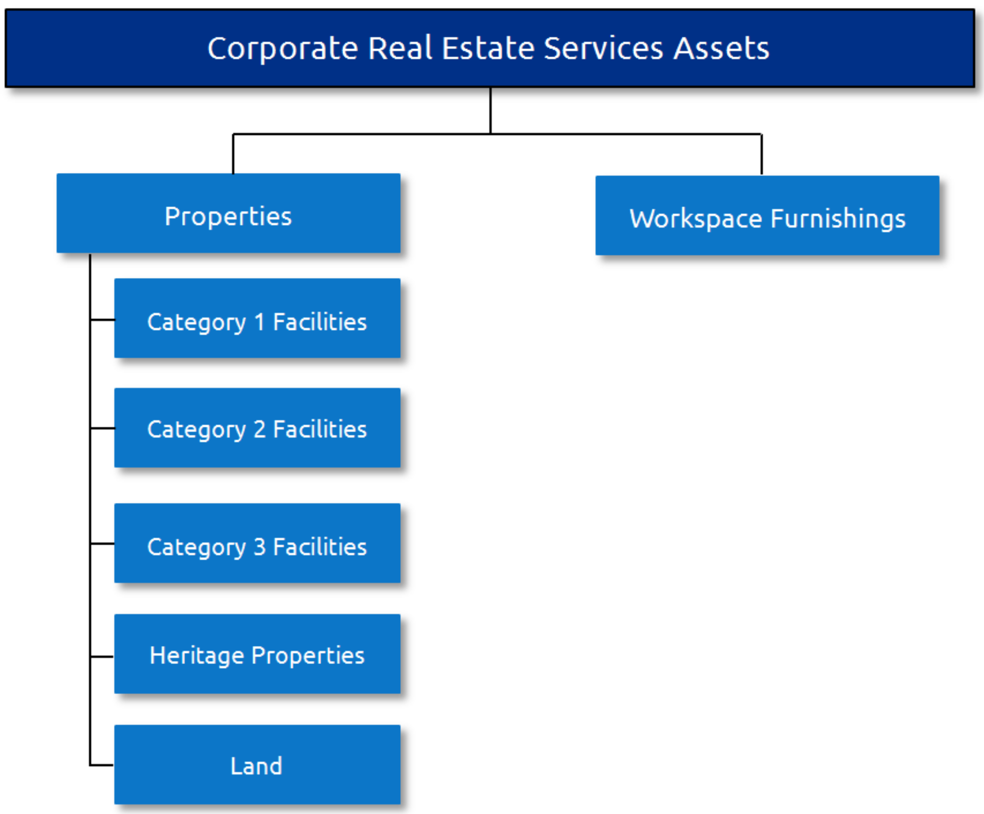


Figure 5.4.8.1.1: Structure of CRES Assets

Union's Service Facilities are divided into two subclasses: Properties and Workspace Furnishings. The Properties subclass is divided further into five categories as shown in Table 5.4.8.1.1. Inventory details are listed in Appendix C**.**

Table 5.4.8.1.1: CRES Asset Inventory

Service Facilities sub-classes	Quantity
Properties (Buildings / Land)	74
Category 1	8
Category 2	8
Category 3	52
Heritage Properties	2
Land	4
Workspace Furnishings	~12,000

Property Categorization

Category 1 Properties are operations or administration facilities located throughout the province that support the critical business needs of natural gas storage, transmission, distribution, central warehousing, customer service, revenue stream and public relations.

Category 2 Properties are operations facilities located throughout the distribution franchise area that provide field level support for natural gas distribution operations and may include a centralized support function such as a fabrication shop, call centre or drafting operations.

Category 3 Properties are field offices and small storage facilities for materials and equipment necessary to support natural gas distribution operations in remote areas of the distribution franchise area.

Heritage Properties are structures located on Union owned locations which may include significant heritage attributes. At this time, these properties are not being used for operational needs.

Land Union owns and maintains parcels of land where facilities have previously existed or where facilities will exist in the future.

5.4.8.1.1 Managed Facilities Ownership

Owned

CRES manages all aspects of building operations at owned facilities, and the occupying business function manages processes related to operations and material storage. Within the CRES portfolio, 67 of the 83 managed facilities are owned.

Leased

CRES manages only the building contents, grounds and property maintenance as required at leased facilities. The occupying business function manages processes related to operations and material storage. Unless otherwise specified, the property owner manages all aspects of capital improvements at leased facilities. 15 of the 82 managed facilities are leased.

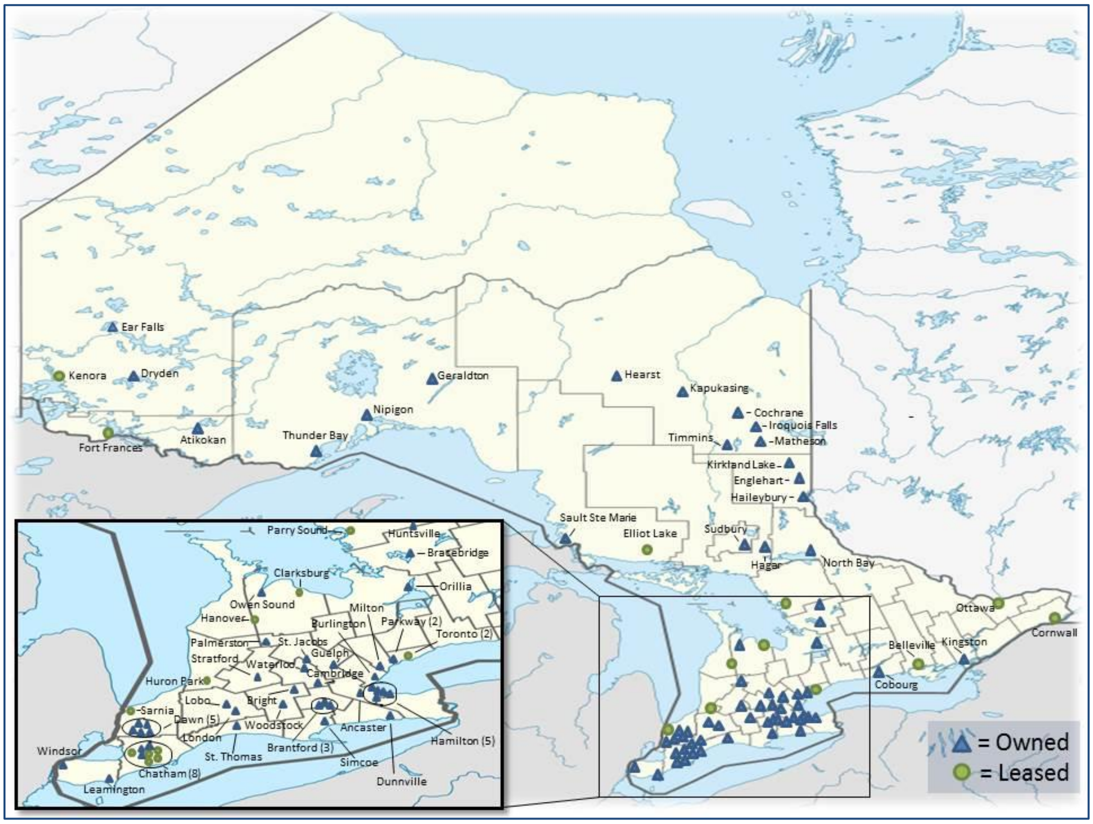


Figure 5.4.8.1.1.1: CRES-managed Service Facilities (owned and leased)

5.4.8.1.2 Asset Class Objectives

Table 5.4.8.1.2.1: Asset Class Objectives

Asset Class Objectives		Measure of success
Create and support safe, efficient, appropriate and collaborative environments for effective business function	Sustain the integrity of all facilities for safe and reliable use	• Physical Assessment: Facility Condition Index (FCI) • Functional Assessment: Adequacy Index (AI)
	Continuously evolve the understanding of condition and risk associated with real estate assets	• Cost per square foot (lease and building OpEx) • Utilization Rate • Risk Mitigated and LRROI • QRA completion %

To achieve these objectives asset investment decisions are governed by the Life Cycle Management policies outlined in Table 5.4.8.1.3.1.

5.4.8.1.3 Life Cycle Management for Real Estate Assets

Table 5.4.8.1.3.1: Life Cycle Management Policies

Life Cycle Stage	Activities
Acquire / Create	• Acquire and design facilities to suit business purposes and ensure safe business function. • Install and construct facilities to meet industry compliance and building standards. • Evaluate asset investment options to ensure best capital decisions are made for acquiring and/or creating real estate assets
Utilize	• Suitably commission real estate assets for safe and efficient use by employees. • Monitor the use of the assets over time to understand utilization and justify future life cycle decisions
Maintain	• Maintain the condition (integrity, longevity and efficiencies) of real estate assets for safe and reliable continuous operations

5.4.8.1.4 Real Estate Condition Methodology (Properties and Workspace Furnishings)

For the properties (buildings/land) asset subclasses, Union uses a Facility Assessment to evaluate and document the following:

- Assess the physical condition of each facility.
- Assess the operational functionality of each facility.

- Identify potential gaps in service area coverage.
- Create a long term real estate portfolio strategy.
- Construct a 'bottom-up' capital plan.
- Create quality indoor environments with access to natural light and views which result in increased productivity, decreases absenteeism and improved morale.

The Facility Assessment is based on a defined set of standards representing industry best practices relating to exterior site works, architectural elements, interiors, furniture, and amenities.

The functional obsolescence or Adequacy Index (AI) is a condition index tool used to illustrate the functional condition of the asset expressed in a percentage ratio of required functional upgrade costs divided by the replacement value of the asset to meet the functional needs, expressed as:

Adequacy Index (AI) Calculation

$$AI = \frac{\text{functional upgrade cost}}{\text{cost to replace the building with its functional equivalent}}$$

Scores between 0 per cent and 49 per cent are considered good. Scores of 50 per cent and above are considered critical.

The physical condition is assessed based on the Facility Condition Index (FCI). The FCI is a generally-accepted industry benchmarking tool. It is a scoring mechanism comparing the relative physical condition of the existing components of a group of facilities. Some Union properties have been inspected for the purpose of calculating an FCI and creating a long-term capital plan. The FCI is calculated as follows:

Facility Condition Index (FCI) Calculation

$$FCI = \frac{\text{cost to remediate immediate or short-term maintenance deficiencies}}{\text{current replacement value of the facility}}$$

Scores between 0 per cent and 5 per cent are considered good. Scores from 6 per cent to 10 per cent are considered fair. Scores between 11 per cent and 30 per cent are considered poor and scores greater than 30 per cent are considered critical.

Functionality and utilization are based on critical functional criteria (yard size, access, sufficient office area, tracked utilization, etc.) and are scored Good, Challenged or Obsolete.

Properties are assessed based on multiple parameters such as site and building functional obsolescence, physical obsolescence, Ontario Building Code (OBC) compliance, and renewal/replacement strategy costs. Each property is assigned a priority rank from highest to lowest. To attain this rank, the AI, FCI and recommended strategy for correcting the deficiencies were considered. Higher priority is given to facilities posing the larger more immediate financial and/or safety risk to the Organization.

OBC requirements must be met depending on the part, group and division each property falls under. These include (but are not limited to) barrier-free path of travel, barrier-free washroom facilities and universal washroom facilities. Furthermore, compliance with fire code regulation such as load bearing structure, fire resistance rating, sprinkler system and combustible/non-combustible construction are also considered. It is important to note that major renovations to a structure may require that area be brought up to current OBC standards, potentially requiring a substantial investment.

5.4.8.1.5 **Property Condition Methodology**

The CRES asset condition is governed by the AI and FCI indices, as well as the building-to-site area coverage (site functional obsolescence). The relationship between these metrics and how they lead to a particular strategic plan in regards to the assets future are visualized in two graphs (Figure 5.4.8.1.5.1).

The graph on the left represents the building adequacy and condition index. The black diamond in the graph indicates the facility assessment. The green area denotes that both the physical (FCI 0-5 per cent) and functional (AI 0-50 per cent) conditions are considered correctable at the current location. The corners on each graph are labeled to indicate the corresponding strategy for facilities that lie in that general area of the graph. The graph on the right represents the site assessment. The green area denotes that deficiencies are correctable on the existing property. The red area indicates the relocation/land acquisition is necessary to meet Union standards.

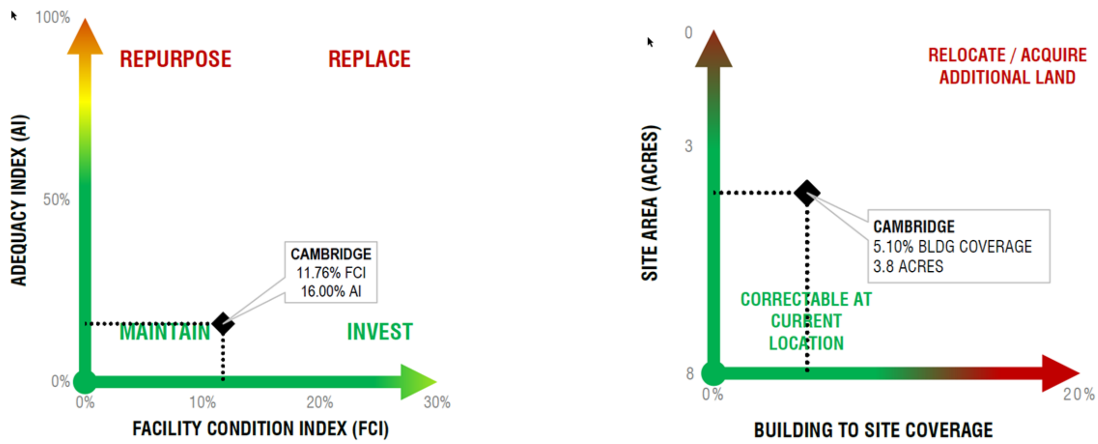


Figure 5.4.8.1.5.1: Sample graphs

A facilities condition is represented in the tables below to indicate if it meets Union's standards and whether the deficiency is correctable or not on the existing property.

Physical Obsolescence: The acceptable Union standard for physical condition is an FCI score of 0 per cent to 5 per cent. The current FCI score of the sample facility is 11.76 per cent. Therefore the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The current facility AI is 16 per cent. Therefore, the functionality of the facility is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence – Site: The acceptable Union standard for functional condition is a 2.5 acre yard with dedicated traffic lanes for entry and departure. The Cambridge site currently does not meet operational requirements. The yard is 0.9 acres with a single access. However, the site has adequate space to accommodate future yard growth.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

5.4.8.1.6 Workplace Furnishings Condition methodology

Furnishings include workstations and office furniture. Furnishings are either considered current (meets current standards) or legacy (does not meet current standards).

Current furniture standards provide:

- Ergonomic support.
- Daylight and views for building occupants through the use of mid-height workspace systems and perimeter placement.
- Task seating required to address a range of body types.
- Consistent workstation configuration, contributing to lower operating costs by creating fixed environments allowing a broad range of administrative requirements without change.
- Designs that utilize materials and features to reduce the ‘cubicle feel’.
- Designs supporting power and network wiring.

Legacy furniture (greater than 20 years old) does not meet Union's current condition standards. Legacy furniture is comprised of furniture systems purchased prior to 1990 when the concept of system furniture was first implemented. The office environment and related standards have evolved immensely over the past 30 years. The systems still in use are high-paneled, impeding daylight into the environments. Legacy furniture has surpassed its 10-year warranty period (the anticipated use length) and is approaching 30 years in age.

In addition, ergonomic requirements have changed; supporting Union's goal of zero injuries in the office. The height of the existing fixed work surfaces is 29 inches, and a contributing factor to repetitive strain injury. Current standard workstations allow for adjustable height work surfaces, empowering employees to adjust their primary work surface to the appropriate height, or to stand if desired.

Ancillary furnishings are all support furnishings including (but not limited to) guest seating, informal and collaborative areas, conference room/common space furniture, filing cabinets and book cases. The condition of this furniture type is based on an assessment of age, physical condition and utilization, and is evaluated as either current (meets current standards) or legacy (does not meet current standards).

5.4.8.1.7 Service Facilities Maintenance

The service facilities maintenance activities, programs and best practices were established to ensure building, employee, and site safety, compliance, and reliability. Service facility maintenance activities are driven by a combination of several different maintenance programs and best practices to ensure building safety, legislative compliance, reliability, quality, value, and functional needs of each business unit are met in order to fulfil Union's core responsibilities as a natural gas utility.

These activities, programs and best practices include internal and third party assessments to critical infrastructure at predefined intervals, proactive and reactive maintenance and repair programs, and strategic renovation or replacement of service facilities to reduce the average age maximizing asset life while balancing costs.

5.4.8.1.8 Summary of Service Facilities Maintenance Capital Projects

Table 5.4.8.1.8.1: Service Facilities 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Service Facilities Maintenance											
Service Facilities Maintenance	5.8	4.1	3.2	3.2	3.5	3.5	3.5	3.5	3.5	8.5	**42.2**
New Service Facilities											
Belleville - New Building		3.5	4.0								**7.5**
CS-Belleville PropertyPurch&Eng.	3.5										**3.5**
Stratford - New Building								1.5	6.5		**8.0**
Service Facilities Modernization											
50 Keil CCHP Equipment	5.7										**5.7**
50 Keil Drive Modernization		4.0	5.0	5.0	5.0	3.5					**22.5**
Cambridge - Refurbishment		3.5									**3.5**
Dawn North Administration Modernization			2.9	5.3							**8.2**
Guelph - Refurbishment					1.5	6.5					**8.0**
London District Office Modernization							1.5	5.0	5.0	5.0	**16.5**
North Bay - Refurbishment						1.5	8.5				**10.0**
Orillia - New Building				1.5	5.0						**6.5**
Sault Ste Marie - Refurbishment							1.5	5.0			**6.5**
Sudbury - Refurbishment										1.5	**1.5**
Service Facilities Total	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**	**150.0**

Service Facilities Maintenance

These projects include mitigation to lifecycle risks including issues with grounds, pavement, roofs, walls, windows, door, interior finishes, heating, ventilation, air conditioning, plumbing, electrical, lighting, furniture, access and building automation systems. Projects in this grouping are also aimed at enhancing physical security to meet existing and new security risks in proactive approach.

Planned expenditures will aid in assuring business continuity, safe reliable natural gas service and potential significant operations and maintenance savings from Heating, Ventilation, and Air Conditioning (HVAC) replacements, Light-emitting diode (LED) lighting conversions and building envelope upgrades.

New Service Facilities

This category includes projects to build new service facilities that are better sized and are in a better location to accommodate the local operations. These also have improved lighting, heating and ventilation systems that will result in lower operating costs and improved security. This approach with a steady pace of spend is consistent with customer engagement feedback.

Service Facilities Modernization (Existing)

These projects will address lifecycle risks, optimize current business unit space layout and ensure compliance with current Ontario Building Code requirements including fire spread mitigation. These projects will also contribute to Union's efforts in conservation of energy at various locations, including Chatham District Office and 50 Keil Drive North, Dawn North Administration Building, and London District Office.

These 30 to 50 year old buildings have been maintained, but would benefit from modernization to aid in assuring business continuity and deliver safe and reliable natural gas service while reducing operating costs.

This approach with a steady pace of spend is consistent with customer engagement feedback.

5.4.8.1.9 Summary of Service Facilities Incremental O&M

Table 5.4.8.1.9.1: Service Facilities 10 Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Additional Security Guards	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5

Additional Security Guards

In support of the security management program, the addition of additional security guards at key facilities will result in increased O&M expenditure.

5.4.8.2 Fleet

Union owns approximately 1,280 vehicles, trailers, and equipment across Ontario from Windsor to Cornwall to Kenora to support Union's operational business needs. These assets include the vehicles listed in Table 5.4.8.2.1 as well as 312 pieces of equipment and 182 trailers.

The vehicles, equipment, and trailers can vary dependent on the operational needs. Vehicles are sub-divided further into heavy, medium, and light vehicles.

Table 5.4.8.2.1: Union Fleet Vehicles

Vehicle	Example	Inventory
Cars	Ford Focus/Escape	48
Light Trucks	Vans, Pick-ups, USR1 Truck	466
Medium Trucks	USR2 & USR3 Trucks, Cube vans etc.	228
Heavy Trucks	Dump Trucks	44

Preventive maintenance activities, processes, procedures and manuals for the fleet assets have been established to ensure asset and employee safety, compliance, and reliability. Maintenance activities are driven by a combination of programs and best practices to ensure vehicle, equipment and trailer safety, legislative compliance, reliability, quality, value, and to ensure the functional needs of each business unit are met.

Optimal replacement is determined by lowest total cost in vehicle's lifetime. The lowest cost is determined by analyzing cost curves for depreciation and maintenance.

Final asset replacement decisions are evaluated against the optimal replacement analysis plus age, mileage, condition, risk of failure and functional need. Each asset is ranked and evaluated annually. Maintenance dollars are spent based on risk with the highest risk items being completed first.

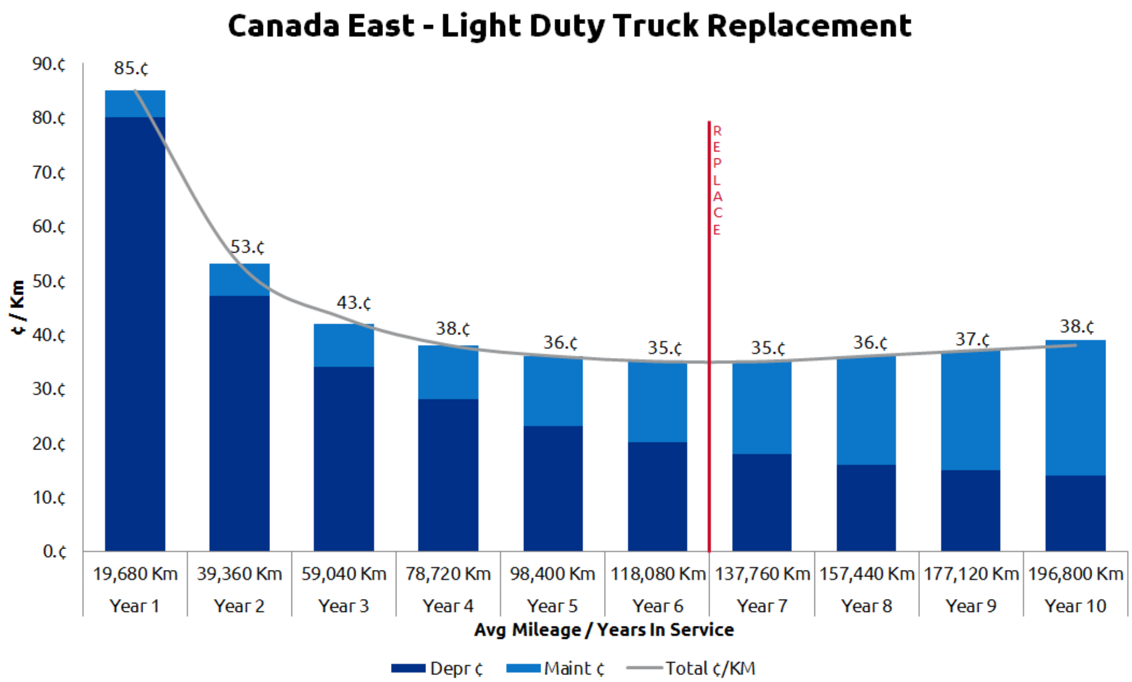


Figure 5.4.8.2.1: Optimal Replacement Analysis – Light Duty Truck

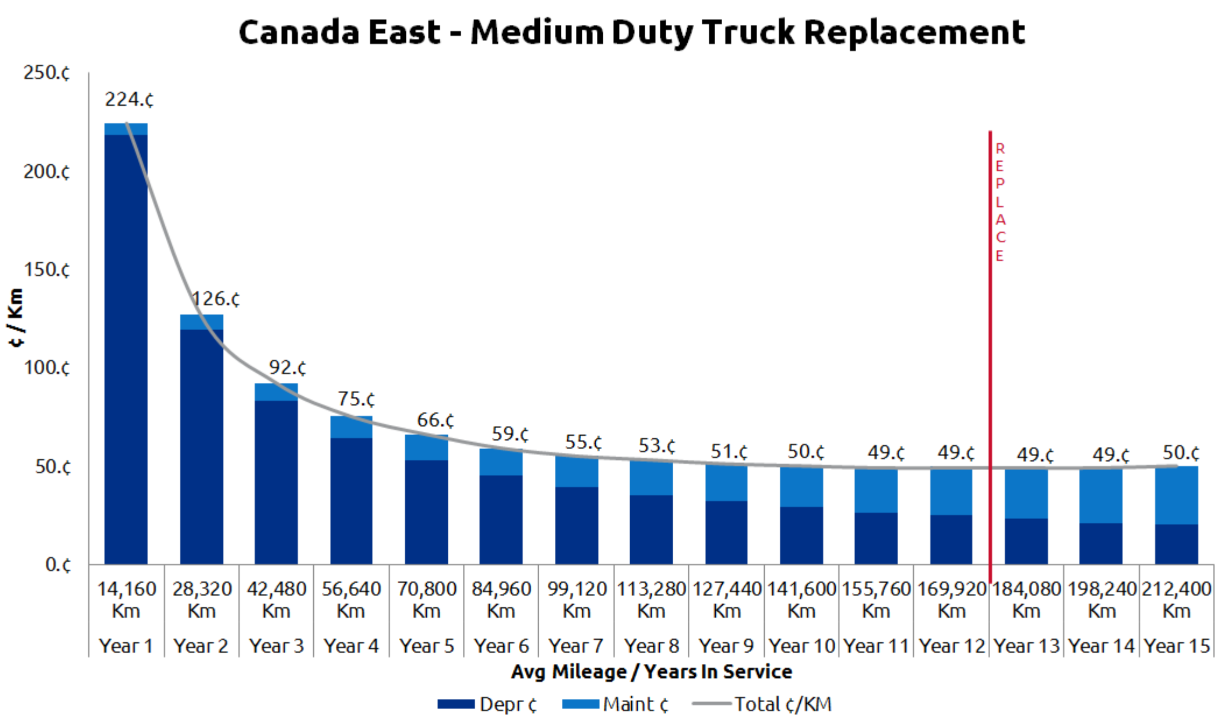


Figure 5.4.8.2.2: Optimal Replacement Analysis – Medium Duty Truck

5.4.8.2.1 Summary of Fleet Maintenane Capital Projects

Table 5.4.8.2.1.1: Fleet 10-Year Forecast of Capital (all $ in millions)

Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Fleet	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	**90.0**

Fleet Replacement

This forecast includes an increase in the years 2019 to 2021 to replace fleet vehicles that would have been replaced in the years 2015 to 2017. During the years 2015 to 2018, the fleet expenditures were reduced as the funds were allocated to higher priority projects. This approach with a steady pace of spend is consistent with customer engagement feedback.

5.4.8.3 Technology and Information Services (TIS)

Technology and Information Services (TIS) applications and related technology work activities are driven by a combination of enhancement projects and lifecycle upgrades/replacements. The overarching objective is to ensure that TIS applications and related technologies provide desired functionality, perform efficiently, and are usable, reliable, maintainable, and compatible with other applications/technologies, while ensuring the required standard of security.

Effort is made to ensure the needs of each business area are met including considerations related to legislative compliance, regulatory orders and financial accounting and reporting requirements.

Work activities include reviews of best practices, internal and third party assessments, development of technology roadmaps, maintenance and replacement of applications and/or technologies.

Business cases are developed for each TIS investment and are prioritized using compliance, lifecycle, financial strategic and reputational strategic drivers.

During the TIS application lifecycle, technology and design reviews are held to ensure new systems are implemented in the most cost effective manner, using standard tools and proper security coding practices.

5.4.8.3.1 Hardware

Hardware includes general hardware used to support the entire business as well as specialized hardware specific to an application or area of the business. General hardware includes workstations, networks, servers, and security. Workstations include laptops, desktops, monitors and accessories, printers, and plotters. Networks consist of routers, switches, hubs, firewalls, devices required to maintain voice communication and video conferencing networks, as well as patch panels cabling systems that link internal local area networks to high-speed data circuits. Servers consist of the devices that operate Union's applications and store data. Security involves the protection of control systems, business applications, computer infrastructure, and data networks.

Specialized hardware products are required to support specific business needs and include meter reading equipment, call centre network devices, and other communication devices that allow work to be completed in remote areas of the franchise as well as maintain the safety of field employees and equipment. The lifespan of hardware assets typically ranges between four and seven years depending on the device. The devices within each group vary in age. A portion of all the hardware assets are upgraded each year to ensure ongoing operational reliability.

5.4.8.3.2 Information Technology Applications

Information Technology (IT) applications include 16 key IT applications that provide critical functionality to Union employees and customers by contributing to the support and growth of Union's natural gas storage, transmission, and distribution business. Key IT applications also rely on ancillary systems that have been added over time to provide additional functionality as the business needs change and grow. There are an additional

64 smaller IT applications that support specific functional business needs. The IT applications can be classified as Commercial-off-the-Shelf (COTS), internally developed solutions, or cloud services. The age range of the internally developed solutions can extend out as far as 20 years before a lifecycle replacement/significant upgrade occurs. Technology upgrades and enhancements may occur regularly to internally developed solutions. The age range of the COTS applications extends out as far as 15 years; however, the majority are within a 10-year range and rely on the vendor to maintain support. Lifecycle activities are based on risk factors identified for each application.

5.4.8.3.3 IT Technologies

The IT technologies asset class contains nine key technologies that are used within IT and are categorized as application integration systems, business intelligence systems, and database systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications. Business intelligence systems allow business data to be queried, reported, and analyzed from Union’s application systems to aid in corporate strategy planning and decision making. Database systems provide the back end relational database technologies for storage of business data, as well as related client software to allow applications to connect to these databases.

The age range of the all of the IT technologies extends to 20 years. However, plans are in place to decommission older IT technologies as more current technologies are available.

5.4.8.3.4 Summary of Technology and Information Services (TIS) Maintenance Capital Projects

Table 5.4.8.3.4.1: TIS 10-Year Forecast of Capital (all $ in millions)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Key Applications											
Banner	2.0	3.5	2.1	2.1	2.3	12.1	32.1	37.3	27.1	2.1	**122.6**
CARE	0.1	6.1	11.2	10.2	9.2	0.2	0.2	0.2	0.2	0.2	**37.6**
CARS	0.1	0.3	7.2	7.4	7.4	2.0	2.3	0.3	0.4	0.8	**27.9**
ConTrax	11.6	0.1	0.4	0.3	0.1	2.4	0.1	0.1	0.1	2.4	**17.5**
Corrosion		1.5	2.3	0.3		0.2	0.3	0.3		0.2	**4.9**
GIS		1.5	0.8	6.0	6.1	6.0	0.6	0.3	0.3	0.8	**22.2**
Meters & Measurement		3.9	1.6	0.6	0.2	0.2	0.4	0.1	0.1	0.4	**7.5**
SCADA	1.0	1.0	1.0	1.0	1.1	2.1	4.2	2.0	1.0	1.0	**15.4**
Service Suite	3.8	0.5	1.0	0.5	0.5	2.5	0.5	0.5	0.5	3.0	**13.3**
Applications - Other	1.5	4.3	3.7	2.9	5.0	2.5	2.1	3.5	2.8	4.5	**32.7**
Hardware	6.3	7.4	4.6	4.6	5.7	8.2	7.6	5.8	5.9	9.3	**65.5**
IT Technologies	1.4	1.1	1.4	1.1	1.3	1.2	1.2	1.4	1.2	1.0	**12.1**
TIS Total	**27.8**	**31.3**	**37.1**	**36.7**	**38.7**	**39.5**	**51.4**	**51.6**	**39.6**	**25.4**	**379.1**

The detailed integration planning of the systems and processes of the two utilities is underway. The resulting integrated structure will influence the ultimate systems and processes spending.

Applications

Changes to TIS Applications are categorized into the following three types:

- **Enhancements** – Small to medium sized projects to add functionality and/or adapt the application to new business requirements.
- **Upgrades** – Primarily focused on applications that leverage vendor software. Regular version upgrades are required in order to maintain vendor support.
- **Lifecycle Projects** – Medium to large projects where the entire system is replaced with either a new in-house developed application or different vendor supplied software. COTS (Commercial-off-the Shelf) or vendor supplied applications are typically life cycled every 10 to 15 years to maintain support. In-house custom develop applications tend to have a longer life span and undergo a lifecycle replacement every 20 to 25 years.

The majority of the proposed TIS capital is for life cycling existing applications. Given there are 16 key applications and lifecycle projects typically take three to four years to implement, there will need to always be two to three active medium to large application projects in order for the systems to be properly working. This supports the desire expressed by Union's customers that costs are kept at a consistent, stable level.

Further, deferring some of the proposed TIS projects could result in outages that take several days to resolve, impacting Union's ability to provide safe and reliable operations – something that Union customers also indicated a strong preference for.

Key Application Projects

Banner – is used to bill Union's 1.5 million residential customers as well as the large commercial and industrial accounts. In 2019 and 2020, a $2.5 million enhancement to the on-line component referred to as My Account is required for compliance with the AODA (Accessibilities for Ontarians with Disabilities Act). During 2024 through to 2027, the application will undergo a major lifecycle replacement as the current version and underlying technologies will be over 20 years old. The other spending is on enhancements to enable the application to continue to meet business needs.

CARE – is Union's gas management system which handles both incoming and outgoing nominations. It validates these requests against Union's pipeline capacity. In 2020 to 2023, CARE will have a major lifecycle replacement to ensure it continues to operate effectively. It is an in-house developed application that was originally developed in 1994. The underlying technologies are no longer supported by the vendor and it's becoming increasingly difficult to maintain resources trained in the older programming tools.

CARS – allows customers and contractors to submit and track their requests to get gas service at their location. In 2021 to 2024, CARS will have a major lifecycle replacement to ensure it continues to operate effectively. It was developed in-house in 2009. The underlying technologies are no longer supported by the vendor and it is becoming increasingly difficult to maintain resources trained in the older programming tools. In 2025, the on-line user interface referred to as Get Connected, will be enhanced to ensure it continues to operate securely.

CONTRAX – provides billing of Distribution, Storage & Transportation services for large Commercial/Industrial accounts and Direct Purchase customers. A lifecycle replacement project was started in 2013 and will finish in 2019. The application had become difficult to support due to the outdated technology and the complexity of the application as a result of having undergone several disparate and complex enhancements since it was initially implemented in 1995.

Corrosion – provides asset-tracking, inspection and field data collection system for routine inspection, maintenance and regulatory compliance activities on Union's pipeline built on vendor provided software. The software is overly complex to use and therefore inefficient. Alternative packages will be investigated as part of the lifecycle project in 2020-21, including potential of consolidating its functions into an existing application.

GIS – is Union's geographic information system (GIS) application for storing spatial and attribute information primarily related to underground assets (e.g. pipe, valves, fittings, district boundaries, structures, intersections, etc.). It provides accurate data for planning and emergency response. The application consists of a suite of purchased software products that will need to be life cycled in 2022 to 2024 to maintain vendor support. The current software version was implemented in 2007.

Meter and Measurement – is a set of applications that captures meter readings from residential, commercial and high volume customers, passing the data onto the appropriate billing systems. In 2020, the residential meter reading application will be upgraded to incorporate reads from meters with AMR devices. It is expected that through the regular life cycling of meters, a sufficient number them will have this feature.

SCADA – the Supervisory Control and Data Acquisition System is used to monitor and control Union's pipelines and stations from a remote location, as well as to make important data accessible for other users for system planning. The software monitors pressures, flows and gas quality. A lifecycle of the SCADA application is planned for 2024 to 2027 with upgrades to both the host application and the telemetry throughout. The last major lifecycle replacement of the vendor software (Cygnet) was in 2011.

Service Suite – is vendor software configured to provide electronic work orders to Union's 400 Utility Services Representatives across Ontario. It is also used to dispatch workers in the event of a gas emergency. The application also accepts completion of work. The last major lifecycle occurred in 2007. A lifecycle project was initiated in 2016 to find a product that could better serve the requirements of the functional area and address the lifecycle issues of the aging software. The decision was made to complete a technical upgrade of the Service Suite system to the newest version of the software. This will address the lifecycle issues associated with the current version and return it to mainstream support with the vendor. The new system will go live mid-2019.

Hardware

These projects include the purchase of new and replacement hardware such as workstations, networks, servers and security components. Also included in this category are specialized devices such as meter reading handhelds, ruggedized laptops for use within the Utility Service trucks, and security cameras for monitoring remote facilities.

IT Technologies

These are projects to install new or upgrade existing IT technologies that include application integration systems, business intelligence systems, database systems, and web delivery systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications.

5.4.8.3.5 Summary of IT Incremental O&M

Table 5.4.8.3.5.1: TIS Ten-Year Forecast of Incremental O&M (all $ in millions, incremental to 2017)

Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Maintenance Activities		0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1

Maintenance Activities

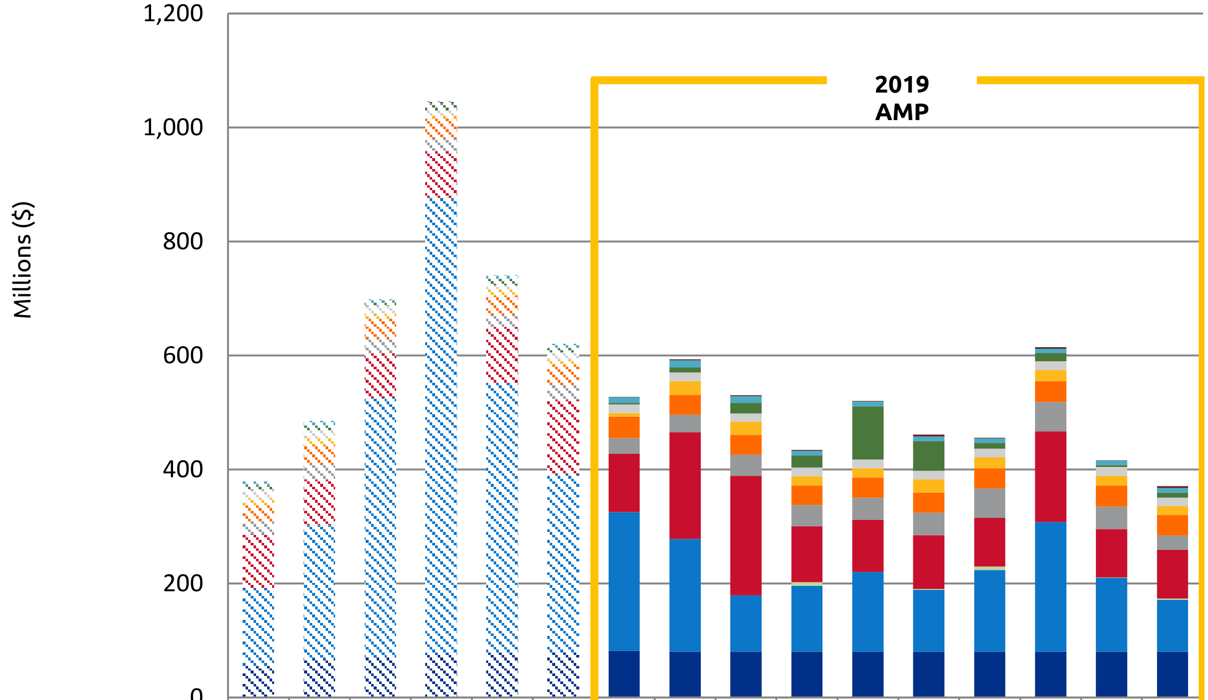
The incremental Operations and Maintenance forecast is maintenance activities for major IT applications. A majority of the incremental operation and maintenance cost is maintenance on new software licences.

5.5 Maintenance Planning Recommendations

The following Table and Figure summarize the maintenance capital forecast recommendations to mitigate risk, maintain integrity, improve reliability, manage integrity and meet compliance requirements. A significant portion of the forecast is for larger, long term projects such as the Meter Exchange Program and Integrity Programs. Larger investments have an impact on certain years. These include replacement of the Windsor Line replacement in 2020 and replacement of Dawn C Plant in 2023.

Table 5.5.1: Maintenance Capital 10-Year Forecast (all $ in millions)

Asset Category	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 Year Total
Pipelines	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1	**1,197.2**
Stations	6.5	24.3	22.6	16.2	16.6	22.8	19.0	19.9	17.7	15.4	**181.0**
Measurement	37.4	34.9	35.0	34.7	35.2	35.3	35.6	36.6	36.9	36.1	**357.6**
Underground Storage	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8	**17.9**
Compression & Dehy	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9	**233.7**
LNG				6.2	0.1	2.1	6.4		0.5	2.4	**17.7**
Service Facilities	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**150.0**
Fleet	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	**90.0**
TIS	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4	**379.1**
Overheads	62.0	49.3	58.3	71.4	60.6	69.6	70.3	48.6	76.1	80.0	**646.1**
Maintenance Total	**264.5**	**364.6**	**409.3**	**309.6**	**360.7**	**342.3**	**302.3**	**355.7**	**282.2**	**279.0**	**3,270.3**

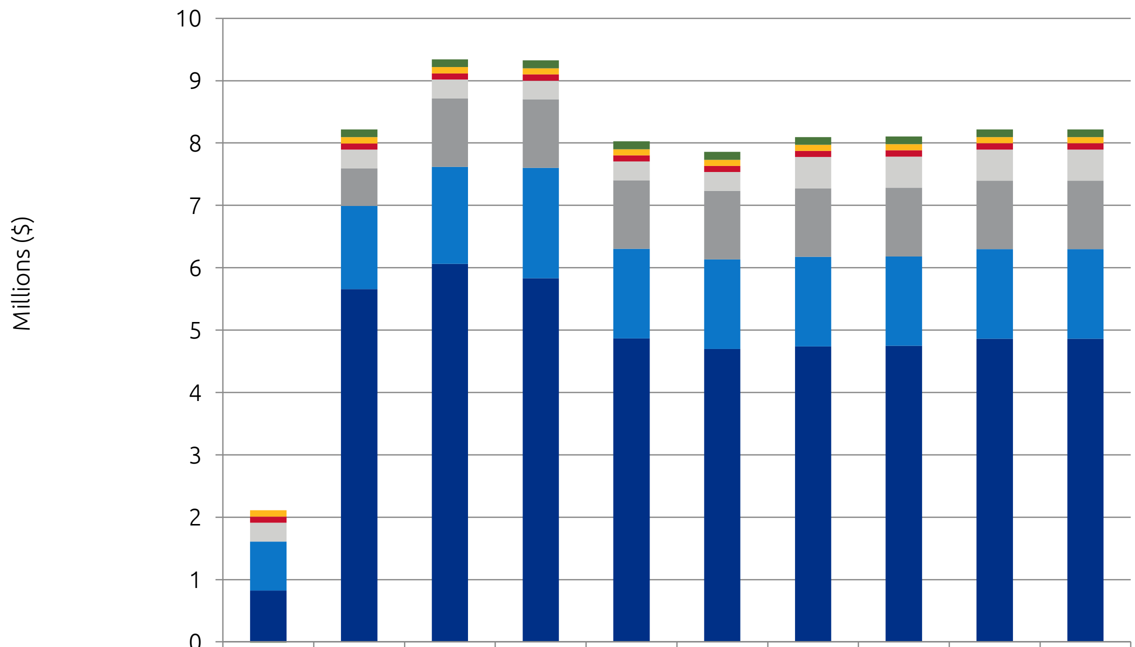


	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Underground Storage	0.5	0.5	1.1	1.7	1.9	0.9	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8
Fleet	7.4	9.1	4.2	3.1	6.2	8.0	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Compression & Dehy	6.6	6.5	6.1	10.3	10.2	6.0	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9
Service Facilities	16.5	13.5	14.2	8.3	8.0	14.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Stations	11.2	13.1	7.8	4.6	11.2	8.8	6.5	24.3	22.6	16.2	16.6	22.8	19.0	19.9	17.7	15.4
Measurement	27.8	33.1	35.6	34.7	32.3	33.6	37.4	34.9	35.0	34.7	35.2	35.3	35.6	36.6	36.9	36.1
TIS	22.9	28.6	26.0	24.0	22.4	27.3	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4
Pipelines	94.9	77.7	78.1	80.6	97.7	129.8	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1
LNG	0.5	1.6	0.3	1.2	1.2	0.5	0.0	0.0	0.0	6.2	0.1	2.1	6.4	0.0	0.5	2.4
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 5.5.1: Asset Maintenance Capital Forecast (all $ in millions)

Table 5.5.2: Incremental O&M 10 Year Forecast (all $ in millions, incremental to 2018)

Project/ Program/ Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Service Facilities	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
TIS		0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Incremental O&M Total	**2.1**	**8.2**	**9.3**	**9.3**	**8.0**	**7.9**	**8.1**	**8.1**	**8.2**	**8.2**



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Service Facilities	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
TIS	0.0	0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9

Figure 5.5.2: Incremental O&M 10-Year Forecast (all $ in millions, incremental to 2018)

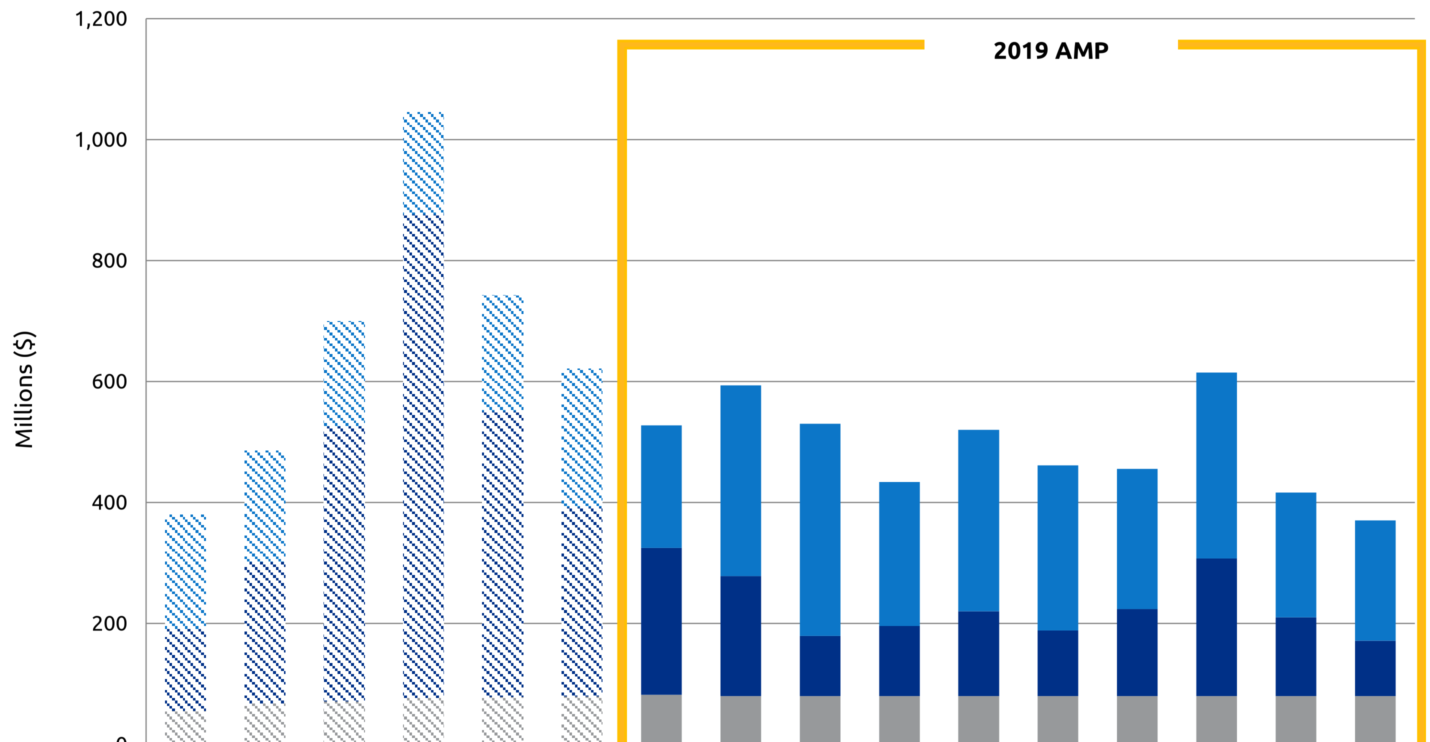
6 Summary of Capital and Incremental Operations and Maintenance (O&M) Expenditures

Using the methodology for prioritization and project selection outlined in Section 4, the following figures show the summary of the capital and incremental O&M expenditures required to meet Union's Purpose, Vision, Goals and Values, and to balance cost, performance and risk. Through careful consideration of the key inputs to the asset investment planning process (risk, customer engagement feedback, resource constraints), this plan provides critical direction for asset management for the next 10 years.

6.1 Total Capital Recommendations

6.1.1 Total Capital

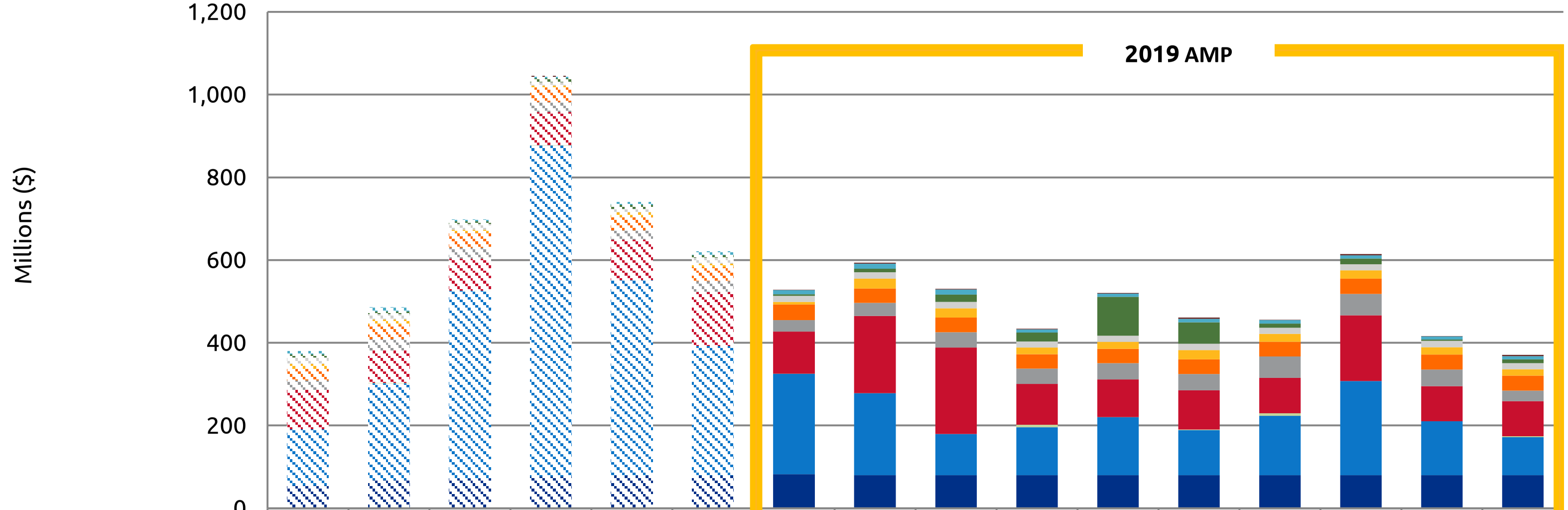
The total capital expenditures are comprised of customer growth and maintenance capital with the associated overheads as calculated by the finance department. These expenditures are depicted in Figure 6.1.1.1. The table also shows the associated investment profile for the previous five years.



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Maintenance	188.2	183.7	173.5	168.3	191.2	229.3	202.5	315.4	351.0	238.3	300.1	272.7	232.1	307.0	206.1	199.0
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 6.1.1.1: Total Capital Expenditures – by Maintenance, Growth, and Overheads

6.1.2 Total Capital by Asset Category



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Underground Storage	0.5	0.5	1.1	1.7	1.9	0.9	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8
Fleet	7.4	9.1	4.2	3.1	6.2	8.0	10.0	12.0	12.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Compression & Dehy	6.6	6.5	6.1	10.3	10.2	6.0	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9
Service Facilities	16.5	13.5	14.2	8.3	8.0	14.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Stations	11.2	13.1	7.8	4.6	11.2	8.8	6.5	24.3	22.6	16.2	16.6	22.8	19.0	19.9	17.7	15.4
Measurement	27.8	33.1	35.6	34.7	32.3	33.6	37.4	34.9	35.0	34.7	35.2	35.3	35.6	36.6	36.9	36.1
TIS	22.9	28.6	26.0	24.0	22.4	27.3	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4
Pipelines	94.9	77.7	78.1	80.6	97.7	129.8	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1
LNG	0.5	1.6	0.3	1.2	1.2	0.5	0.0	0.0	0.0	6.2	0.1	2.1	6.4	0.0	0.5	2.4
Growth	135.7	233.7	454.2	799.4	472.2	312.3	243.1	198.1	99.1	115.8	140.3	108.6	143.6	227.6	130.2	91.4
Overheads	55.7	68.2	71.5	77.3	78.7	79.8	82.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0

Figure 6.1.2.1 Total Capital Expenditures – by Category and Growth

6.1.3 Total Capital by Priority Level

To provide some additional understanding of the composition of the capital investment plan, Figure 6.1.3.1 shows the expenditure profile by priority level. Priority 1 is classified as mandatory work for which there is little flexibility on timing. Priority 2 work, although having somewhat more flexibility than Priority 1, is still fairly inflexible in timing. From the standpoint of risk, Risk I (Priority 1) level projects (of which the company currently has none) and Risk II level projects (Priority 2) are considered to be intolerable risks and must have some form of mitigation action completed within a defined timeframe.

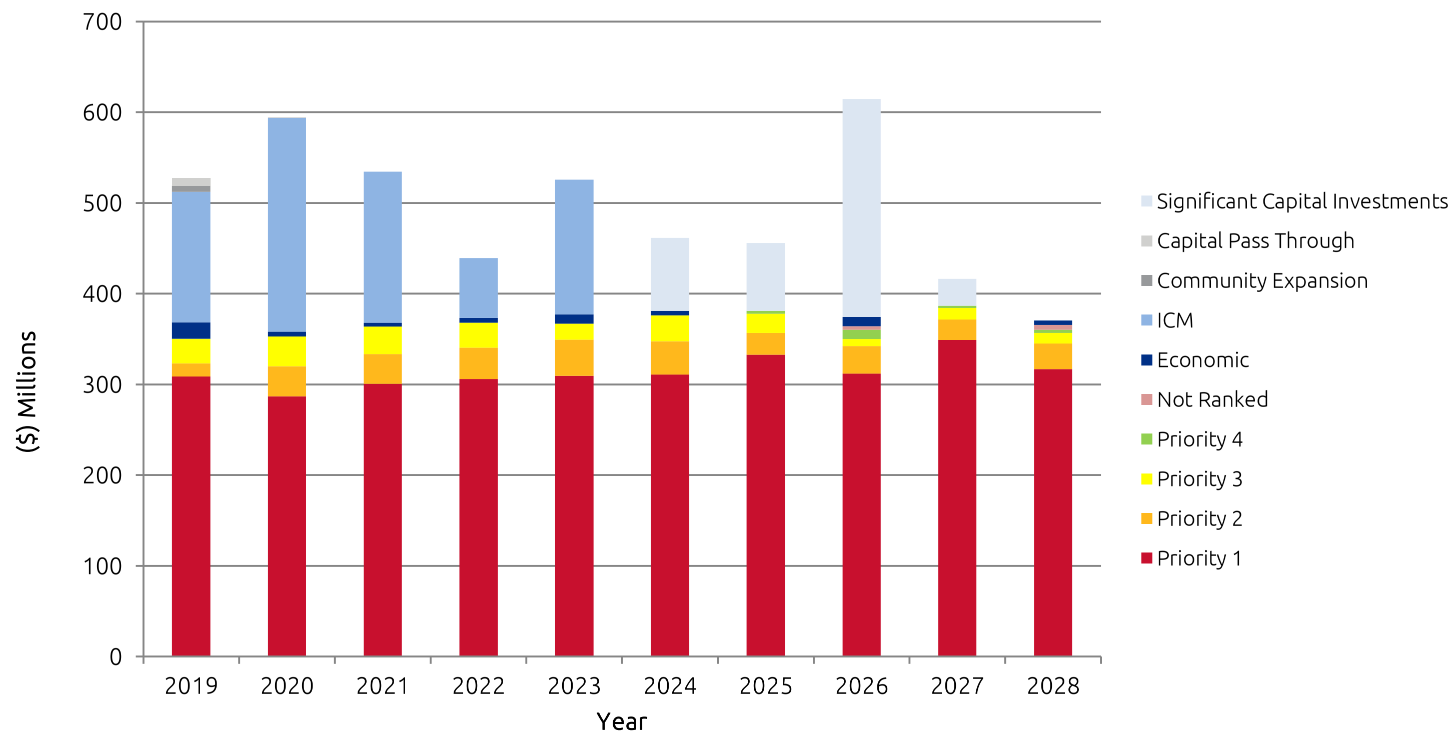
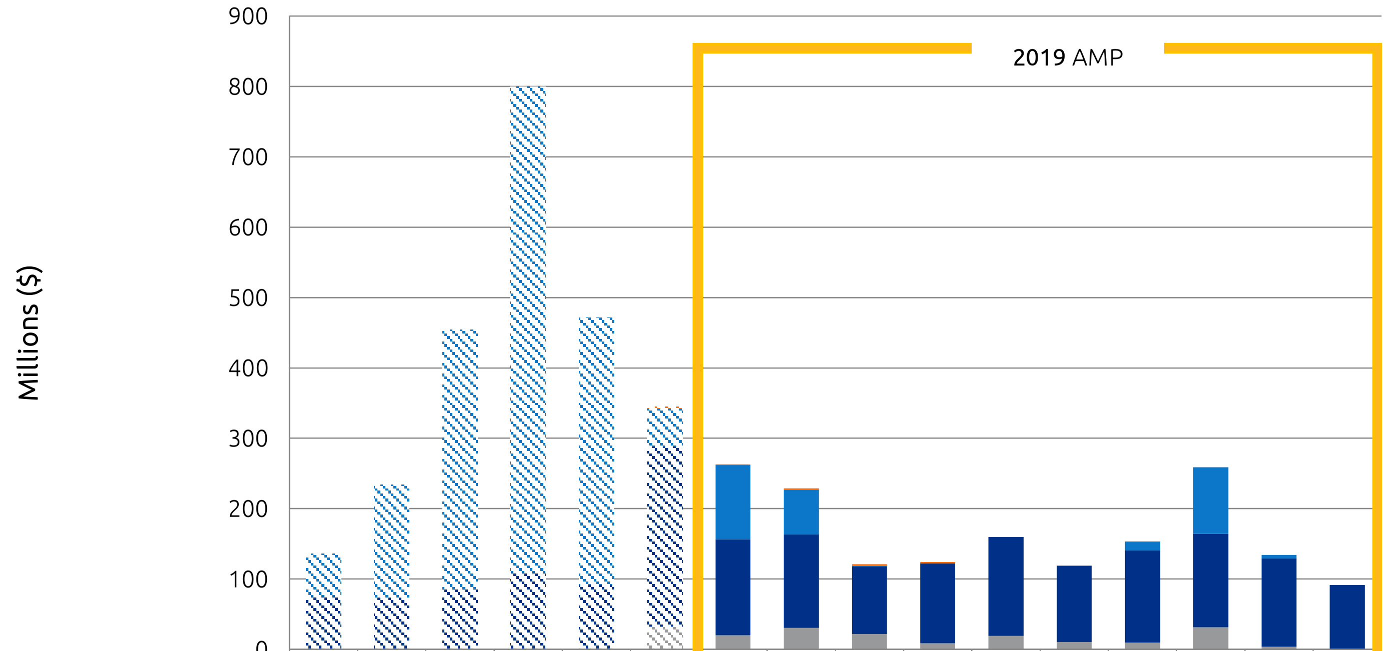


Figure 6.1.3.1: Total Capital Expenditures – by Priority Level

6.2 Asset Growth Recommendations

Within the customer growth plan are general customer growth, distribution reinforcement, transmission reinforcement, system reinforcement, as well as Compressed Natural Gas (CNG) growth opportunities. The following figure shows the growth capital profile for the 10-year plan with five years of history.

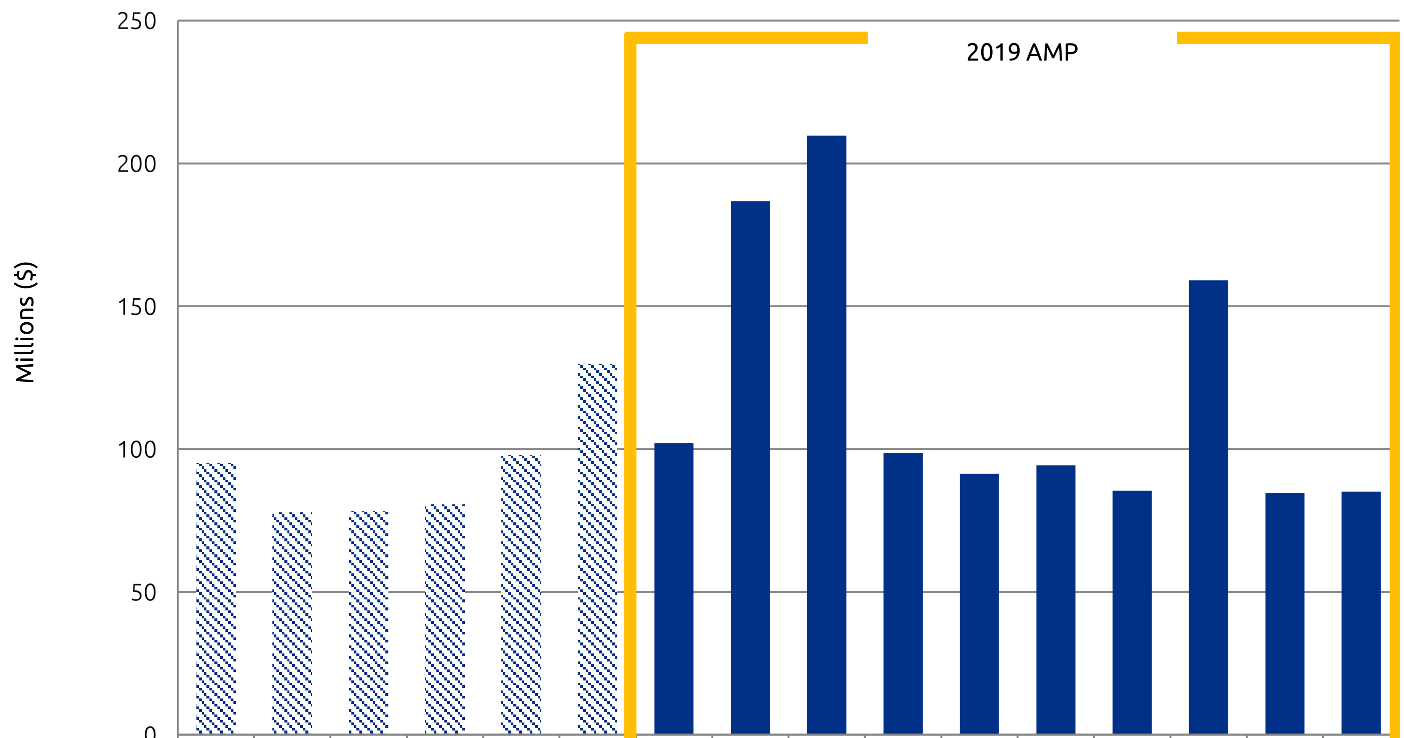


	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Other - CNG						3.0	1.0	2.3	1.9	1.9	0.0	0.0	0.0	0.0	0.0	0.0
System Growth	60.3	160.2	368.0	690.0	380.0	53.0	105.8	63.2	1.3	0.0	0.0	0.3	12.8	94.7	4.9	0.0
Distribution Growth	75.4	73.6	86.3	109.4	92.1	256.3	136.3	132.7	95.9	113.9	140.3	108.3	130.8	132.9	125.3	91.4
Overheads						32.5	20.0	30.7	21.7	8.6	19.4	10.4	9.7	31.4	3.9	0.0

Figure 6.3.1: Growth Capital Profile – by System Growth, Distribution Growth and Other – CNG/RNG Growth

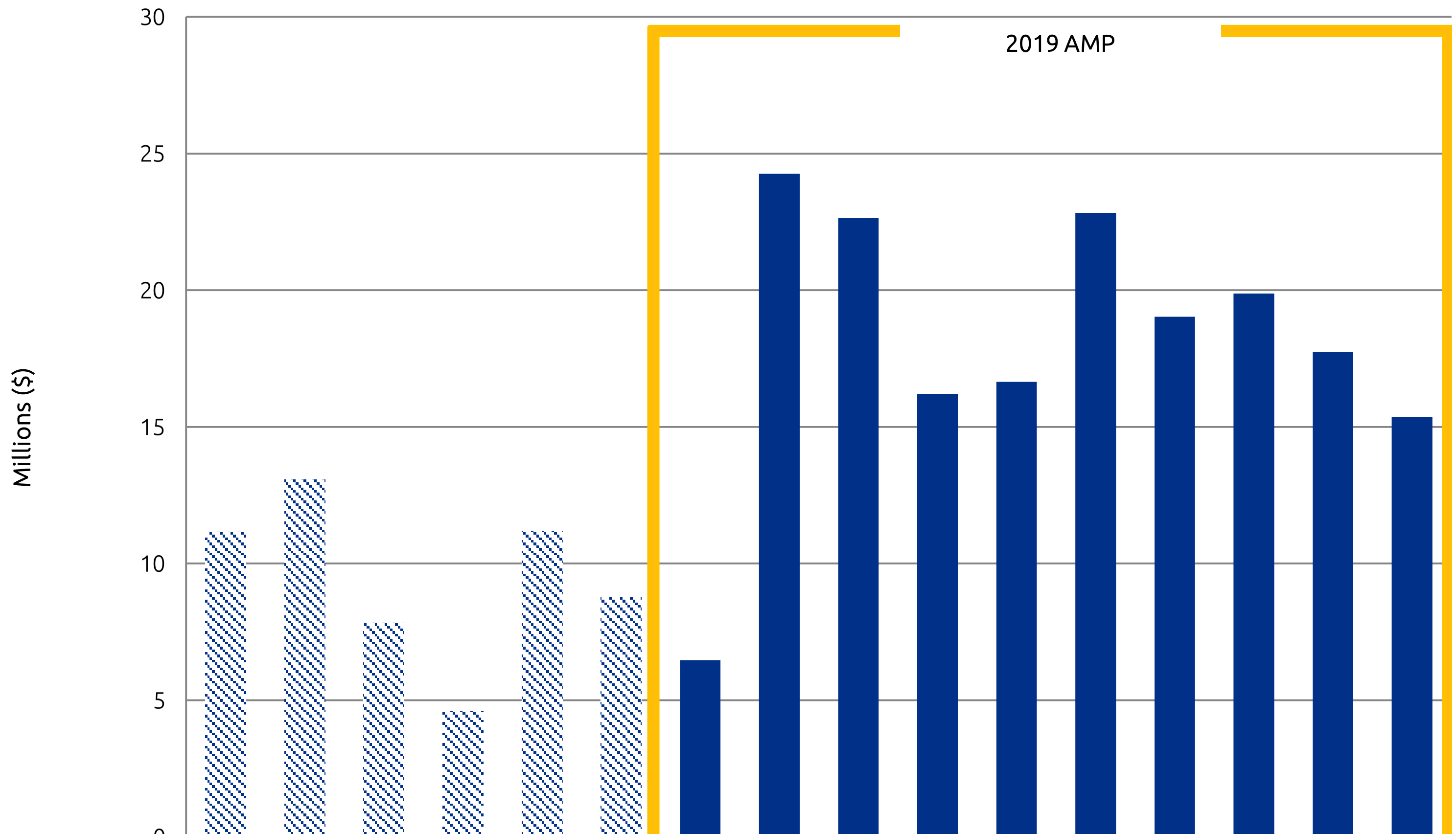
6.3 Maintenance Planning Recommendations

The maintenance capital plan contains all capital investments not associated with growth in the following asset categories: Pipelines, Stations, Underground Storage, Measurement, Compression and Dehydration, Liquefied Natural Gas (LNG), Service Facilities, Fleet and Technology & Information Services (TIS).



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Pipelines	94.9	77.7	78.1	80.6	97.7	129.8	102.1	186.8	209.7	98.7	91.4	94.3	85.4	159.1	84.6	85.1

Figure 6.4.1: Maintenance Capital Plan – by Pipelines



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations	11.2	13.1	7.8	4.6	11.2	8.8	6.5	24.3	22.6	16.2	16.6	22.8	19.0	19.9	17.7	15.4

Figure 6.4.2: Maintenance capital plan – by Stations

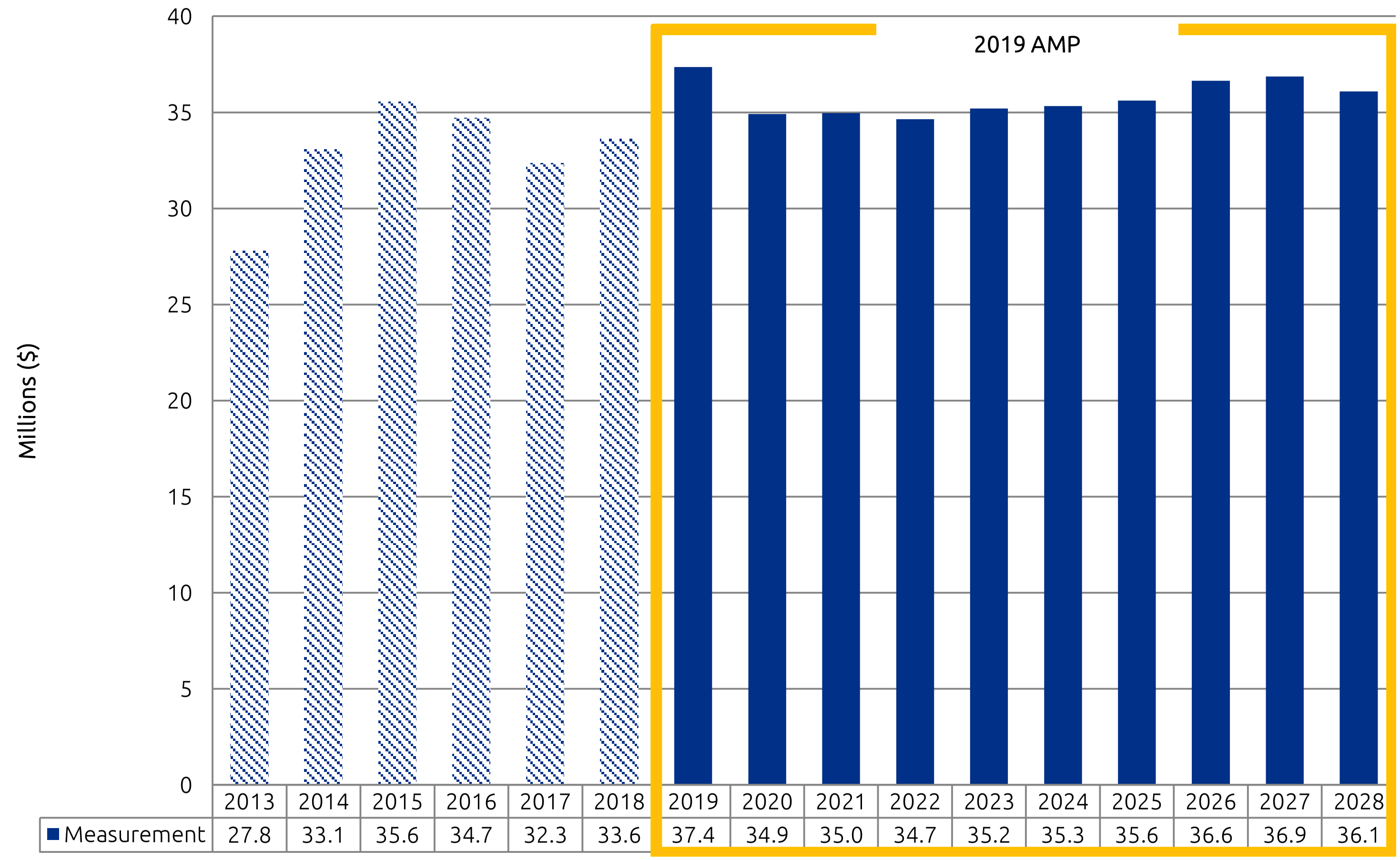
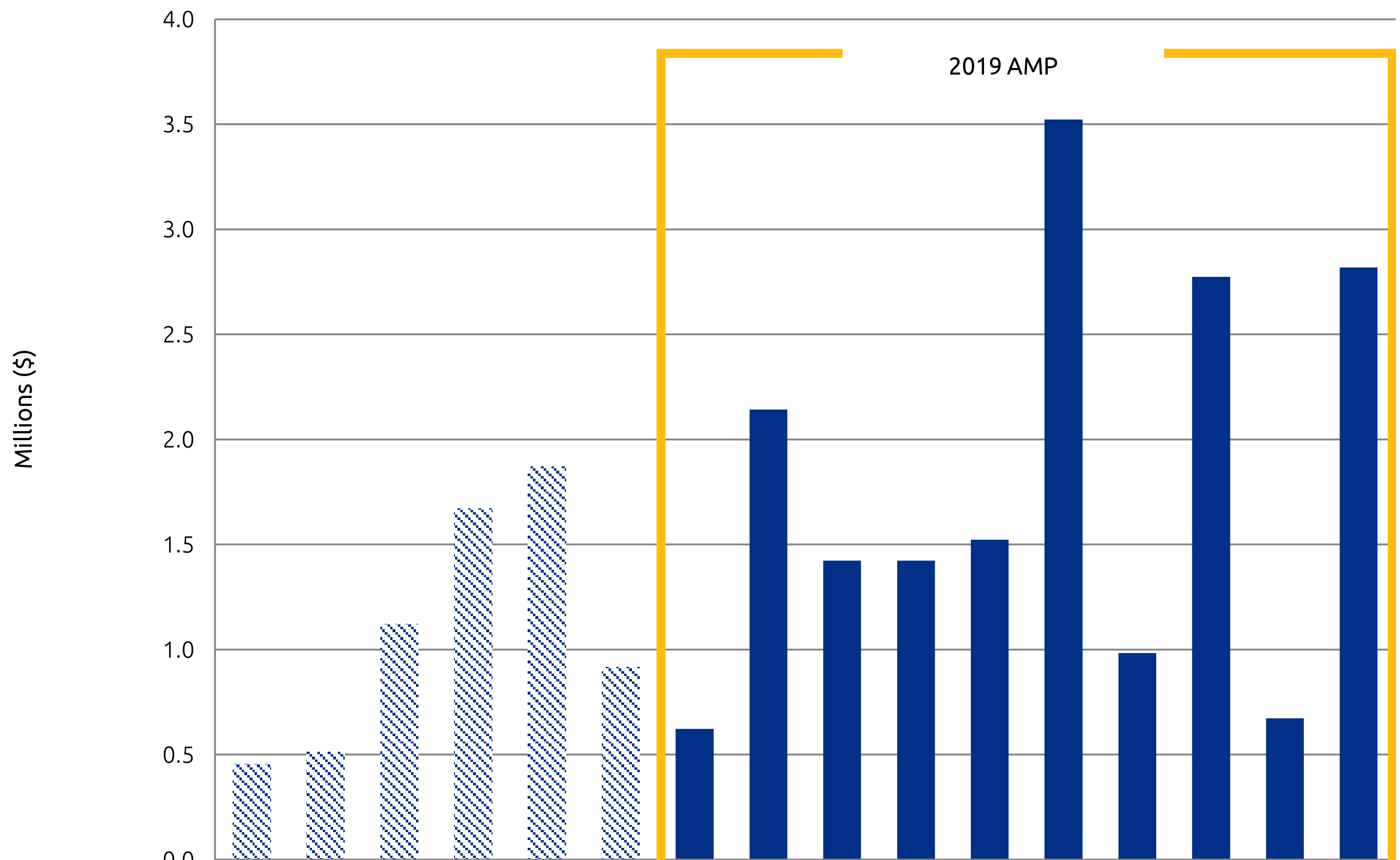
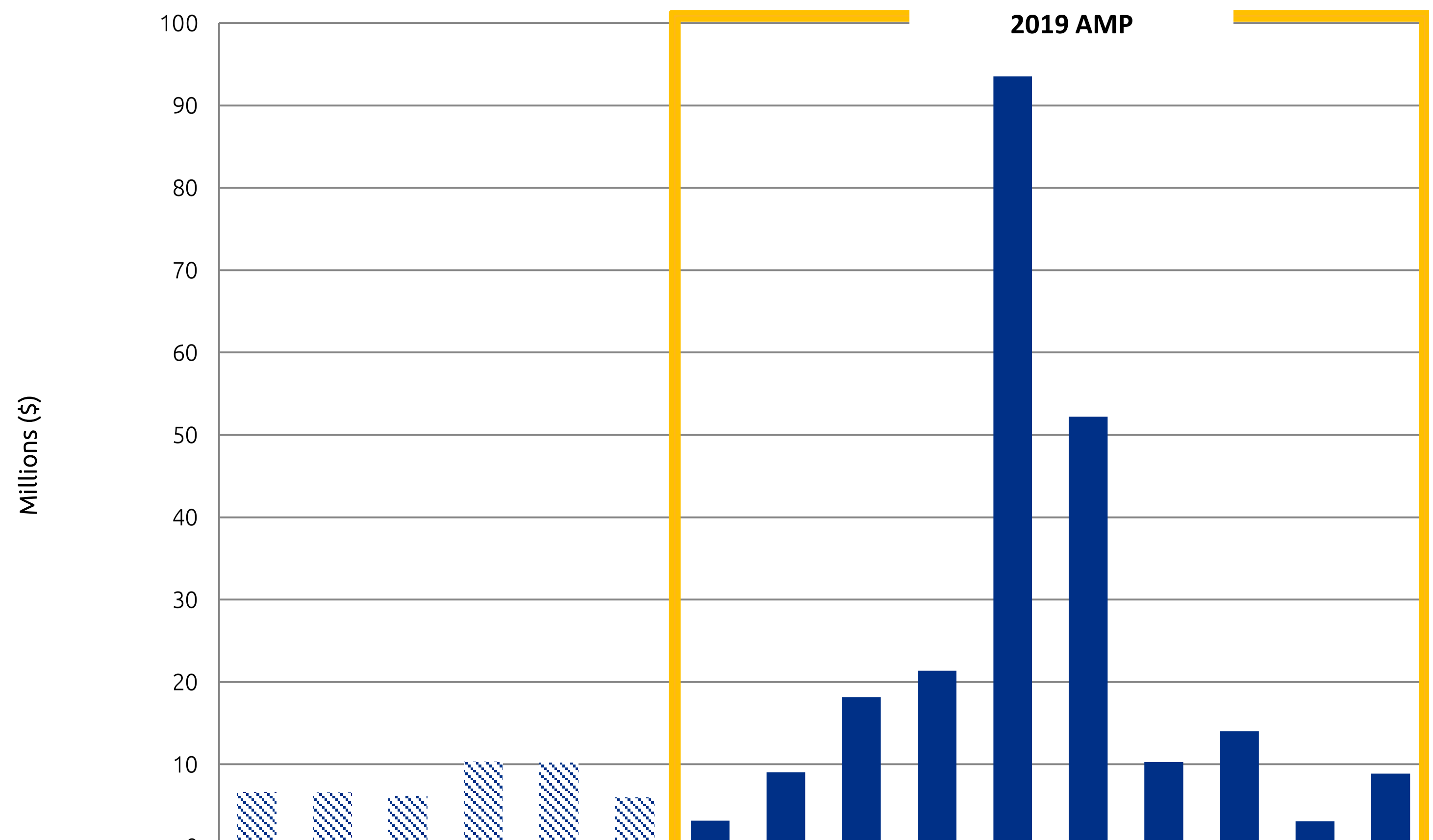


Figure 6.4.3.: Maintenance capital plan – by Measurement



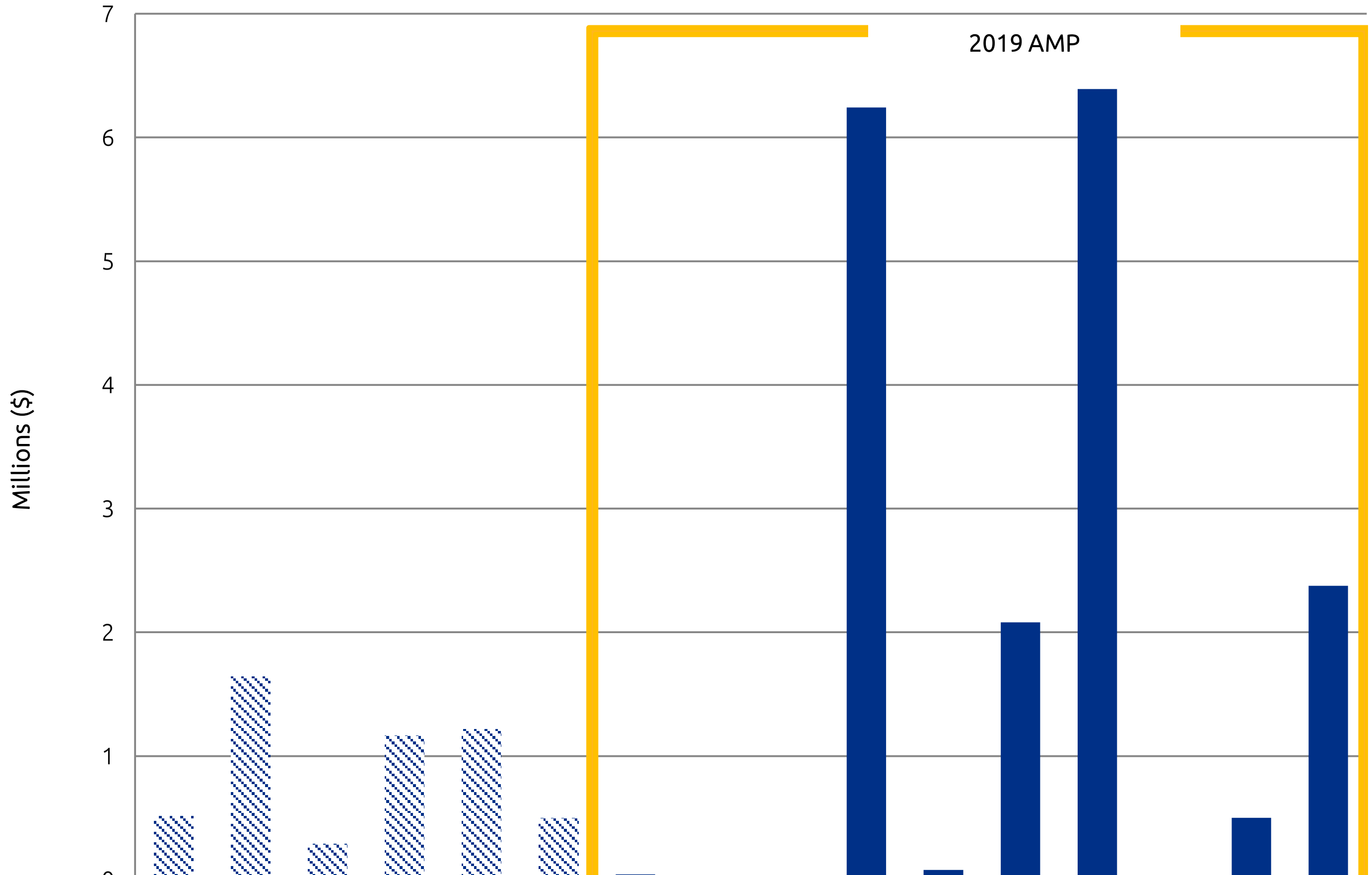
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Underground Storage	0.5	0.5	1.1	1.7	1.9	0.9	0.6	2.1	1.4	1.4	1.5	3.5	1.0	2.8	0.7	2.8

Figure 6.4.4: Maintenance Capital Plan – by Underground Storage



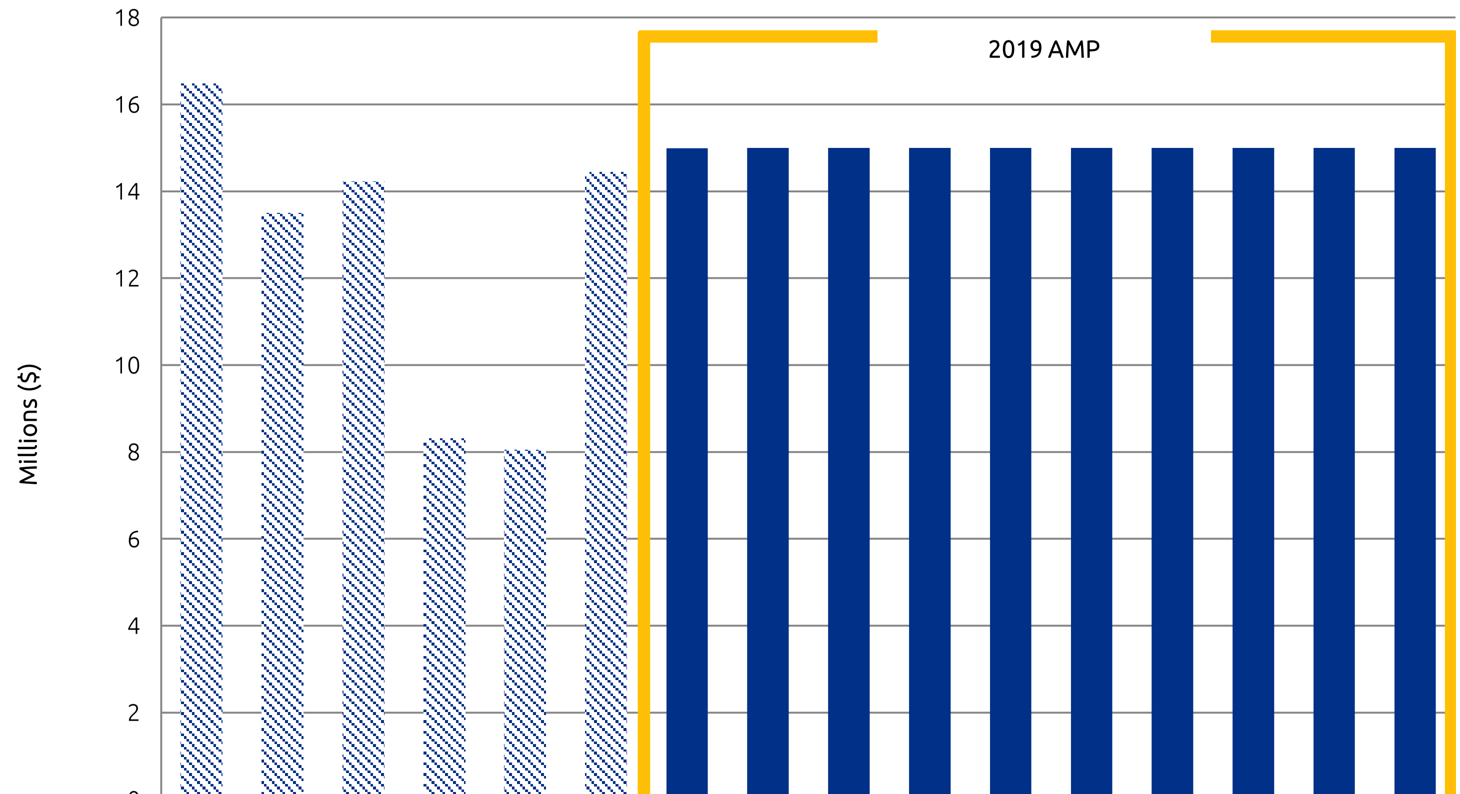
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Compression & Dehy	6.6	6.5	6.1	10.3	10.2	6.0	3.1	9.0	18.2	21.4	93.5	52.2	10.3	14.0	3.1	8.9

Figure 6.4.5: Maintenance Capital Plan – by Compression and Dehydration



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
LNG	0.5	1.6	0.3	1.2	1.2	0.5	0.0	0.0	0.0	6.2	0.1	2.1	6.4	0.0	0.5	2.4

Figure 6.4.6: Maintenance Capital Plan – by Liquefied Natural Gas (LNG)



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Service Facilities	16.5	13.5	14.2	8.3	8.0	14.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0

Figure 6.4.7: Maintenance Capital Plan – by Service Facilities

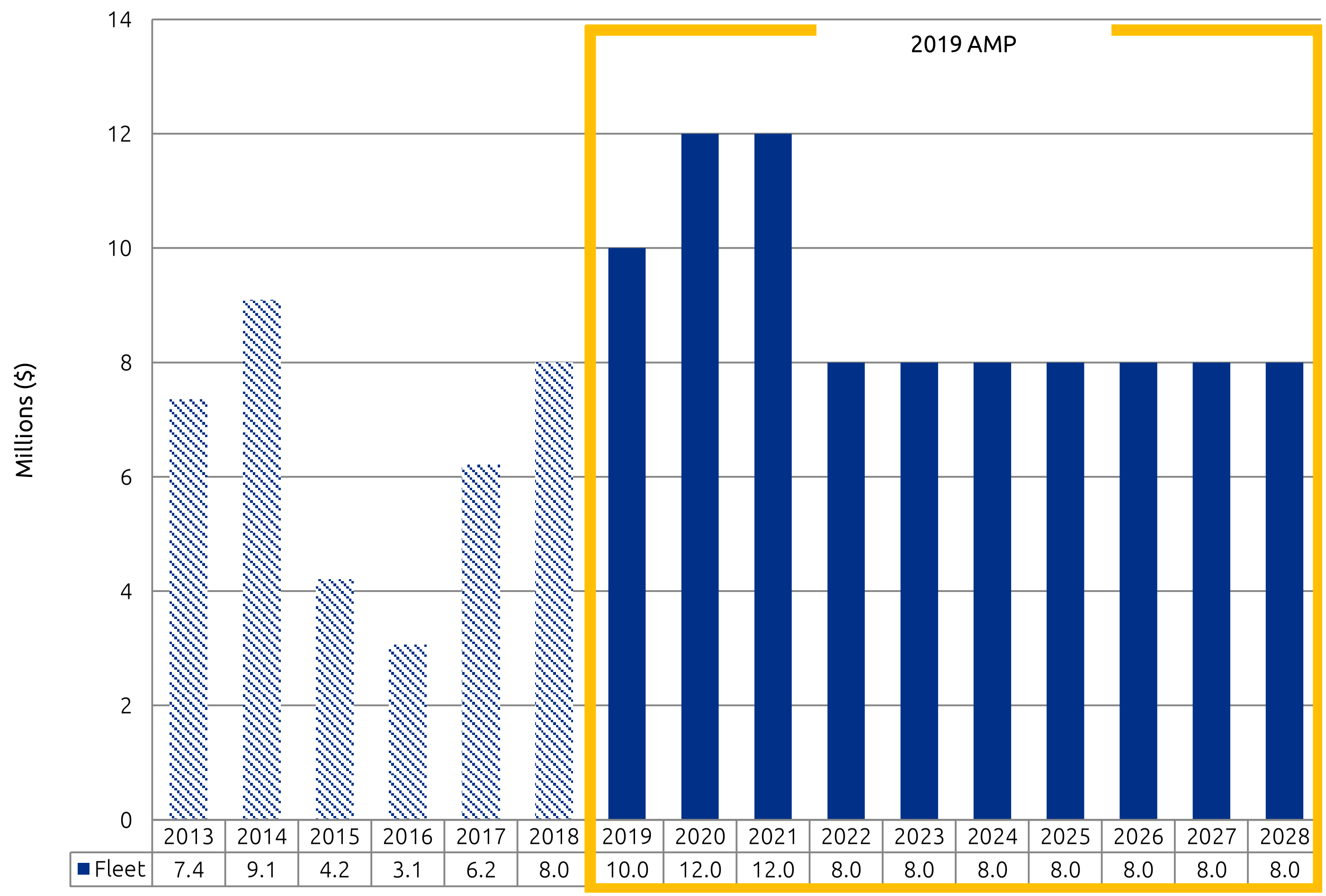
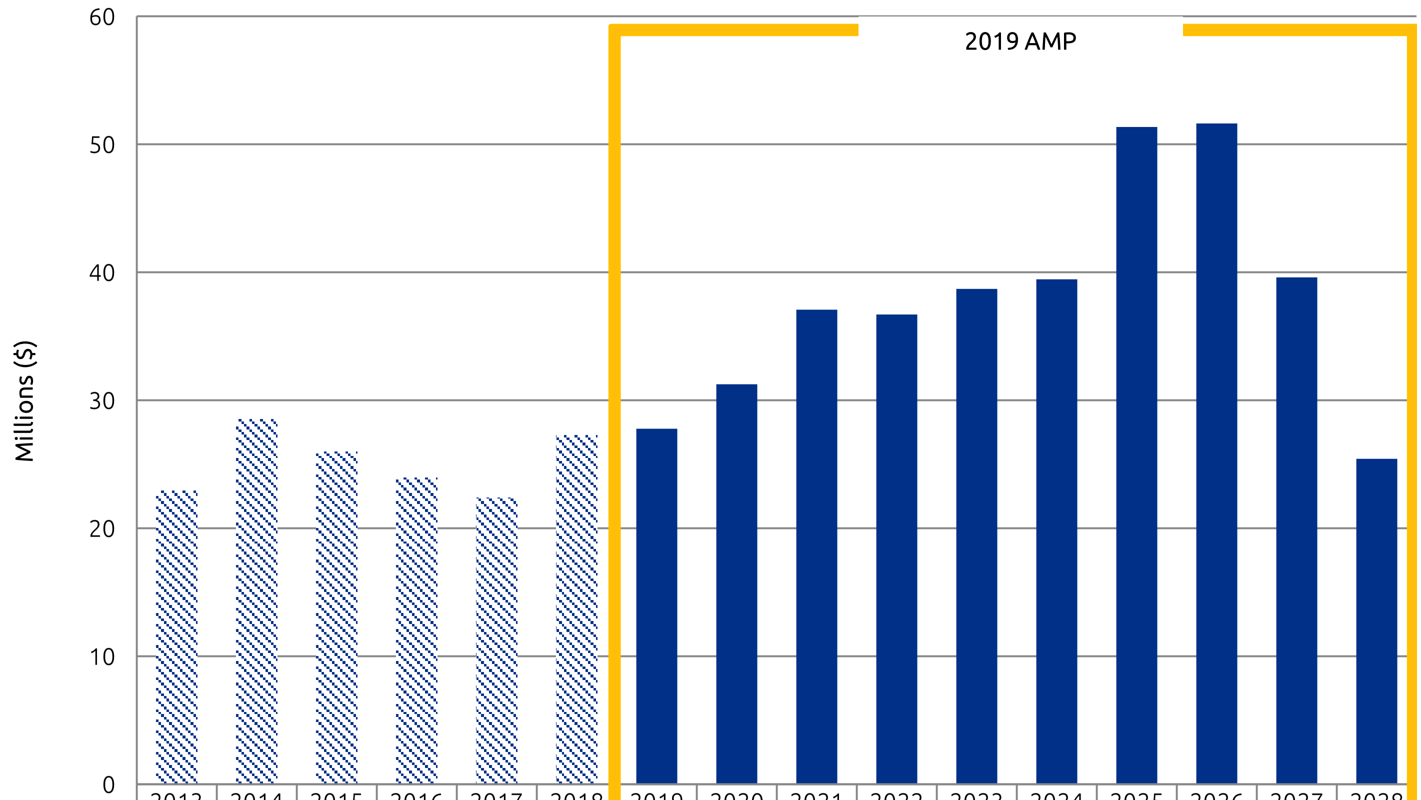


Figure 6.4.8: Maintenance Capital Plan – by Fleet

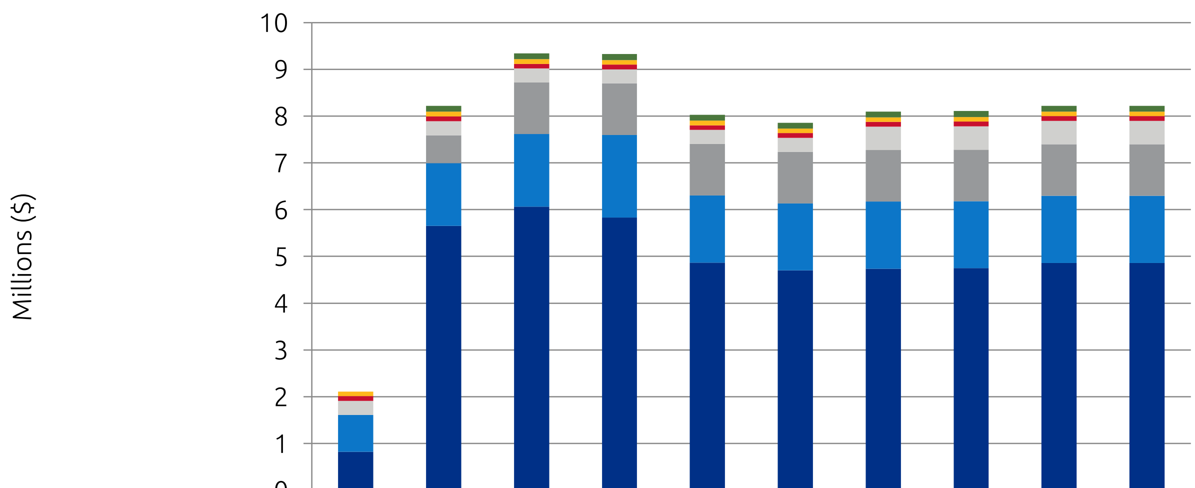


	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TIS	22.9	28.6	26.0	24.0	22.4	27.3	27.8	31.3	37.1	36.7	38.7	39.5	51.4	51.6	39.6	25.4

Figure 6.4.9: Maintenance Capital Plan – Technology & Information Systems (TIS)

6.4 Incremental O&M

The following figure outlines the proposed incremental operating expenditures required to maintain the required level of safety and reliability over the ten-year period. Incremental O&M expense in this context is relative to the current budget year (2018). While it is being shown as incremental O&M, it is expected that any increases in O&M in support of specific programs herein will be offset by O&M reductions in other areas, resulting in no overall increases in O&M expenditures.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Stations	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Underground Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Measurement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CRES	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.5
IT	0.0	0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Compression & Dehy	0.8	1.3	1.6	1.8	1.4	1.4	1.4	1.4	1.4	1.4
Pipelines	0.8	5.7	6.1	5.8	4.9	4.7	4.7	4.7	4.9	4.9

Figure 6.5.1: Incremental O&M Expenditures

6.5 Assumptions

The 10-year capital plan is based on the best available information at the time of optimizing the portfolio. Key assumptions, as detailed in the following tables provide a basis for interpretations.

Table 6.6.1: Assumptions for All Categories

Assumption	Basis for Assumption (Union)
Future costs are valued at 2018 Present Value.	Current practice forecasts projects based on 2018 rates. An annual inflation factor has not been applied to asset classes (with the exception of customer growth and the meter exchange program, which assumes a 1.73 per cent annual inflation).
All cost estimates are based on available information as of July 2018.	
All Risk Assessments are based on risk models and methodology as of March 2018.	Using Union's risk management processes in alignment with the IMS risk element, risks are reviewed and updated accordingly.
Projects in flight that span over multiple years must continue until complete.	Once a project is in progress it is inefficient and costly to terminate.
Capital overhead costs are included in the Asset Management Plan.	The plan also includes the following costs: interest during construction, labour and benefits, Alliance Partner overhead costs.
Historical actual costs are valued at execution years' actual value.	Historical values are not adjusted to be expressed in present value.

Table 6.6.2: Renewal Assumptions

Assumption	Basis for Assumption (Union)
Asset Health provides a reasonable representation for asset condition and remaining asset life for forecasting purposes.	Reliability Engineering is used to understand the health of assets. Based on projected life cycles, consequences of failure, tacit knowledge, and asset data, risk is determined. Renewal projects are planned to reduce this risk to the lowest practicable level.
Optimization of renewal projects produces a forecast that maintains an acceptable level of risk to the organization.	

Table 6.6.3: Customer Growth Assumptions

Assumption	Basis for Assumption (Union)
In-franchise Customer growth is forecasted using historical trends and economic projections for the planning period.	The Customer Growth Forecast considers new housing starts, meetings with builders and developers, municipal growth forecasts. Facilities Business Plans are completed and validated against econometric forecasts. Contract customer growth includes a combination of customer commitment and historical growth trends.
Ex-Franchise customer growth is forecast using historical trends, as well as customer and market intelligence.	The ex-franchise Growth forecast considers the opportunity for growth in various customer market locations using external consultants and individual ex-franchise customer interactions and discussions. The forecast also takes into consideration projected customer turn-back as an offset to growth.
Load Gathering and Simulation is based on current understanding of temperature inputs and estimated customer consumptions.	Distribution planning uses peak hourly rates while system planning uses peak daily rates for design to ensure that the design day requirements are met. The Company is evaluating the scope of its Carbon Strategy and subsequent impact on customer growth forecasts. Various technologies (e.g. smart thermostats) and Energy Efficiency programs (e.g. Demand Side Management) are being assessed to determine potential impacts on peak hour demand in the ongoing Integrated Resource Planning (IRP) study as directed through EB-2015-0029. These potential impacts to peak hour demand and customer growth forecasts have not been incorporated in this Asset Management Plan due to the current uncertainty. Any outcomes resulting from the IRP study will be factored into future Asset Management Plans.

Table 6.6.4: Solution Planning Assumptions

Assumption	Basis for Assumption (Union)
Budgeting and forecast is determined through the solution planning process.	Estimates are determined considering region and work type to accurately forecast. Appropriate project planning processes are followed.

Appendix A - Key Terms

Per cent (%) SMYS: Based upon Canadian Standards Association Z662 – Oil and Gas Pipeline Systems:

$$S_h = \frac{P*D}{2*t} \qquad \% \text{ SMYS} = (S_h/\text{SMYS})*10$$

Where: S_h is the design operating stress,
P is the MOP of the pipe,
D is the outside diameter of the pipe,
t is the nominal wall thickness of the pipe
SMYS is the specified minimum yield strength of the pipe

Compressor: A mechanical device for increasing the pressure of natural gas for purposes of transmission or for storage in underground storage facilities

Compressor Station: Permanent facilities which contain one or more compressors used to supply the energy needs to move natural gas through the pipeline systems at increased pressures.

Dawn: Located southeast of Sarnia, Ontario, Dawn is referred to as a Hub as it represents the point where Union's supply, underground storage and transmission systems meet. A number of other ex-franchise pipeline systems (e.g. TCPL, Vector) are interconnected to Union's system at Dawn

Dehydration Plant: A natural gas processing facility that removes water vapour by passing natural gas through a glycol contactor, which absorbs water vapour from the natural gas stream and dries the natural gas

GHG: Greenhouse Gas

LDC: Local Distribution Companies

NPS: Nominal Pipe Size – approximate exterior pipe diameter in inches

Remote Terminal Unit (RTU): a dedicated electronic controller used for data acquisition and processing.

Supervisory Control and Data Acquisition System (SCADA) – the system used to monitor and control systems from a remote location, as well as to supply important data and make it accessible for casual users.

sm^3/hr: A gas measurement of standard cubic meters per hour of gas volume passed through a meter is converted to standard units applying pressure and temperature factors.

SMYS: Specified Minimum Yield Strength - The minimum yield strength prescribed by the specification under which the material is purchased.

TC: Temperature Compensate

Appendix B - Measurement Maintenance Tactics

Measurement Asset Sub-Class	Device Type	Maintenance Drivers	Maintenance Strategy & Tactics
Gas Meters	• Diaphragm meters (1.4 million) • Rotary meters (17,506) • Turbine meters (600) • Ultrasonic meters (commercial and interconnects) (7850 & 80)	• Compliance • Life cycle	• Diaphragm meters – Compliance sampling. Repaired or retired when removed. • Other meters - Planned maintenance as per company procedures. Condition based monitoring/time triggers. Seal expiry – out of date removal. Preventive maintenance - repair and redeploy or retire
Electronic Volume Correctors	• Electronic rotary modules (16,023) • Electronic Volume Integrators (2208) • AMR Devices (80,057)	• Compliance • Battery replacement • Life cycle	• Planned maintenance as per company procedures. Condition based/time triggers. Seal expiry – out of date removal. Preventive maintenance - repair and redeploy. Proactive battery replacement program
Odourization Systems **(Bypass & Injection)**	• MOIS injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)	• Safety • Compliance • Reliability • Life cycle	• Visual inspections • Planned and unplanned maintenance • Monitoring alarms and diagnostics
Gas Monitoring & Control Systems	• RTU (400) • Communication equipment(cellular, satellite, radio) – (300) • Transmitters (1500) • Power supplies etc.	• Safety • Compliance • Operational sustainability • Reliability	• Visual inspections • Planned and unplanned maintenance • Monitoring alarms and diagnostics

Appendix C - Service Facilities Location Information

Facility Category	Ownership Status	Location Name	Address	Building Area (sq ft)	Age of Facility	Total All Furnishings
1	Own	Brantford	348 Elgin St., Brantford, N3T 5M4	45,330	23	484
1	Own	Bright	866139 Township Rd 10 - Bright N0J 1B0	10,213	1	99
1	Own	Chatham 50 Keil	50 Keil Drive North, Chatham, N7M 5M1	193,533	53	3434
1	Own	Dawn North Admin	3333 Bentpath Line, Dresden, N0P 1M0	17,417	48	267
1	Own	Lobo	11025 Ivan Drive - Ilderton N0M 2A0	13,768	2	83
1	Own	London	109 Commissioners Rd, London, N6A 4P1	66,840	50	699
1	Own	North Bay	36 Charles Street, North Bay, P1B 8K7	50,600	54	387
1	Own	Parkway West	6699 8th Line - Milton L9E 1A4	10,206	3	87
2	Own	Burlington Office	4475 Mainway, Burlington	23,000	10	303
2	Own	Chatham 20 Bloomfield	20 Bloomfield Road, Chatham, N7M 5M1	50,599	4	1002
2	Own	Chatham 555 Riverview	555 Riverview Drive, Chatham, N7M 5M1	60,000	46	415
2	Own	Kingston	1653 Venture Drive. Kingston, K7P 0E9	30,850	9	326
2	Own	Stoney Creek	918 South Service, Stoney Creek L8E 5M4	54,500	5	798
2	Own	Thunder Bay	1211 Amber Drive, Thunder Bay, P7B 6M4	44,285	22	420
2	Own	Waterloo	603 Kumpf Drive, Waterloo, N2J 4A4	40,032	7	430
2	Own	Windsor	3840 Rhodes Drive, Windsor N8W 5C2	35,725	9	503
3	Own	Ancaster	1474 Sandhill Dr., Ancaster, L9G 4V5	5,524	26	51
3	Own	Atikokan	426 O'Brien St., Atikokan, P0T 1C0	1,338	51	8
3	Leased	Belleville	127 Enterprise Dr., Belleville, K8N 4Z5	13,750	30	74
3	Own	Bracebridge	342 Eccleston Drive, Bracebridge, P1L 1V5	934	51	4
3	Own	Cambridge	221 Avenue Road, Cambridge, N1K 7Z1	8,530	56	71
3	Leased	Chatham 496 Riverview	496 Riverview Drive, Chatham, N7M 5M1	9,153	45	132
3	Leased	Chatham 745 Richmond St	745 Richmond St, Chatham N7M 5J5	21,800	N/A	456
3	Leased	Chatham 750 Richmond St.	705 Richmond St, Chatham N7M 5J5	12,130	N/A	0
3	Leased	Chatham Airport Hangar	14th. Line (R. R. #2)+B43, Blenheim,	5,758	N/A	10
3	Leased	Chatham King St.	100 King St. W, Chatham, N7M 6A9	32,000	38	0
3	Own	Clarksburg	369 Clark Street, Clarksburg	880	3	2
3	Own	Cobourg	520 Thompson St, Cobourg K9A 0E9	7,186	12	60
3	Own	Cochrane	156 Fifth Ave., Cochrane, P0L 1C0	1,442	52	20
3	Leased	Cornwall	2910 Copeland, Box 157, Cornwall, K6H 6W2	6,980	22	111
3	Own	Dawn Mechanics Building	1409 Dawn Valley Rd	10,500	N/A	40
3	Own	Dryden	304 Kennedy Road, Dryden, P8N 2Y8	1,798	39	14
3	Own	Dunnville	1202 Pine Street, Dunnville, N1A 2M9	6,994	28	47
3	Own	Ear Falls	5 Mills St, Ear Falls, P0V 1T0	960	4	8
3	Leased	Elliot Lake	14 Oakland Blvd., Elliot Lake, P5A 2T1	2,100	39	16

Facility Category	Ownership Status	Location Name	Address	Building Area (sq ft)	Age of Facility	Total All Furnishings
3	Own	Englehart	137 Third Street, Englehart, P0J 1H0	400	N/A	4
3	Leased	Fort Frances	851 McIrvine., Fort Frances, P9A 2Y8	3500	N/A	33
3	Own	Geraldton	1017 Main St., Geraldton, P0T 1M0	1,464	55	17
3	Own	Guelph	10 Surrey Street, Guelph, NIH 3P5	6,659	61	109
3	Own	Haileybury	450 Meridian Ave, Haileybury,P0J 1K0	2,428	53	14
3	Own	Hamilton Park Street	133 Park Street N., Hamilton, L8N 1E7	1,428	58	19
3	Own	Hamilton Pritchard Rd	335 Pritchard Road, Hamilton	7,186	11	65
3	Leased	Hanover	69-14th Ave Unit 2, Hanover	1,600	N/A	33
3	Own	Hearst	51 Eighth St., Hearst, P0L 1G0	848	45	19
3	Own	Huntsville	184 Main Street West, Huntsville, P1H 1Y1	590	49	19
3	Leased	Huron Park	420 Quebec Avenue Huron Park ON	1,455	78	17
3	Own	Iroquois Falls	522 d'Iberville Ave., Iroquois Falls, P0K 1G0	1,650	52	6
3	Own	Kapuskasing	47 Burnelle Rd., Kapuskasing, P5N 2M1	4,330	28	27
3	Leased	Kenora - Keewatin	4091 Hwy #17 West, Keewatin, P0X 1C0	2,500	N/A	38
3	Own	Kirkland Lake	14 Kirkland St. E., Kirkland Lake, P2N 3H7	2,411	54	13
3	Own	Leamington	357 Oak St. Centre, Leamington, N8H 4W8	4,803	57	54
3	Own	Matheson	413 Park Lane, Matheson, P0K 1N0	565	50	6
3	Own	Milton	8015 Esquesing, Milton, L9T 2X8	7,000	24	52
3	Own	Nipigon	2 Wadsworth Dr., Nipigon, P0T 2J0	1,282	55	9
3	Own	Orillia	425 Memorial Ave, Orillia, L3V 6K2	12,254	44	89
3	Own	Owen Sound	1602 23rd St. East, Owen Sound,	7,300	12	63
3	Own	Palmerston	206 Whites Rd. Palmerston	720	N/A	7
3	Leased	Parry Sound	12 Seguin, Parry Sound P2A 2M5	730	5	5
3	Own	Sarnia	140 Business Park Dr., Sarnia	11,485	2	97
3	Own	Sault Ste. Marie	10 Industrial Court, Sault Ste. Marie, P6B 5W6	9,479	40	86
3	Own	Simcoe	RR #7 Hillcrest Rd., Simcoe, N3Y 4K6	11,594	62	58
3	Own	St. Thomas	25 Sparling Road, St. Thomas, N5P 3T5	6,638	39	56
3	Own	Stratford	827 Erie St., RR #3, Stratford, N5A 6S4	6,996	50	61
3	Own	Sudbury	828 Falconbridge Rd., Sudbury, P3A 4S3	36,717	34	174
3	Own	Timmins	615 Moneta St., Timmins, P4N 7X4	13,681	59	165
3	Leased	Toronto 2300 Yonge St	2300 Yonge St, Toronto, M4P 1E4	2,650	13	53
3	Leased	Toronto 777 Bay St	777 Bay Street, Toronto, M5G 2C8	10,581	13	354
3	Own	Woodstock	350 Beards Lane, Woodstock, NAS 3C2	8,832	36	33
Heritage	Own	McCurdy Farmhouse	6689 Eigth Line Milton ON	N/A	128	0
Heritage	Own	Tomas Robinson House	6603 Eigth Line Milton ON	N/A	150	0

Facility Category	Ownership Status	Location Name	Address	Building Area (sq ft)	Age of Facility	Total All Furnishings
Land	Own	Belleville (land purchase 2017)	Jack Ellis Way, Belleville ON	0	0	0
Land	Own	Brantford Colborne St	315 Colborne Street, N3S 3N1	0	N/A	0
Land	Own	Brantford East Ave	11 East Ave, Brantford, N3S 7P4	0	N/A	0
Land	Own	Hamilton Strathearne	360 Strathearne Ave. Hamilton	0	N/A	0
STO	Own	Dawn EOC Building	1390 Dawn Valley Rd	6,810	N/A	75
STO	Own	Dawn Sewage Lagoon	1362 Dawn Valley Rd	270	N/A	0
STO	Own	Dawn South Admin	1380 Dawn Valley Rd	13,500	N/A	116
STO	Own	Dawn Warehouse	1362 Dawn valley Rd	16,000	N/A	16
STO	Own	Hagar	317 Northern & Central Rd - Hagar P0M 1X0	2,314	N/A	N/A
STO	Own	Parkway East	6626 9th Line - Mississauga - L5N 0C1		N/A	N/A
STO	Own	Parkway Healing Garden	6699 Eidth Line Milton ON L9E 1A4	0	3	0
STO	Own	Parkway Snake Habitat	6699 Eidth Line Milton ON L9E 1A4	0	3	0

Appendix D – Project Descriptions

1 Growth

1.1 Byron Transmission Station Rebuild Project (AMP ID 1518)

The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.*

NOTE: **Only regular rate growth is available until 2022, assuming all previously identified contract customers bring on their requested loads. If contracts fall through or are decreased, capacity is freed up on the system.*

1.1.1 Scope

The Byron Transmission Station Rebuild Project is a full rebuild currently scheduled to be completed in 2022.

- Purchase of land is in the plans for 2018 as additional land will be required.
- As part of the rebuild, the existing station will provide gas to the customers fed off of Byron Transmission Station, acting as temporary regulation.
- The regulations runs will be split so that the 6,160 kPa MOP feeds the 3,450 kPa MOP system and the 1,380 kPa MOP system will feed the 420 kPa MOP system.
- A new heating system (boiler system) will replace the existing inefficient and large volume glycol boilers. As a result of splitting the regulation runs, heating load requirements are reduced and efficiency of the system is increased.
- Monitor/operator regulation runs will replace the current design and position the station for future growth as existing regulators are at maximum capacity. This will also result in lower emissions (token relief versus existing full relief) and reduce noise (station situated in densely populated and growing neighbourhood).
- Existing orifice meters will be replaced by turbine meters to ensure accurate area measurement as well as measurement used for odourization purposes.
- The majority of station piping installed in 1968 will be removed and replaced with new pipe sized for future growth eliminating current velocity concerns.

All of the modifications to be completed as a result of this rebuild enhance station safety, reliability, and maintainability, positioning the area for growth out to 2044, assuming reinforcement is completed upstream and downstream as needed. There is potential for additional capacity with relatively minor station changes in 2044 and beyond.

1.1.2 Expenditures

Total capital expenditure for this project is $349 thousand in 2021 and $15.2 million in 2022.

1.1.3 Resources

These larger full station rebuild projects are traditionally planned and designed by the Major Projects department. Planning has a team of dedicated full-time employees that will continue to manage and execute major projects such as the Byron Transmission Rebuild. The construction work will be managed by Major Projects and a contractor will execute the work. Depending on the scope, the construction contractor resourcing will be managed through a combination of existing Environmental Assessment (EA) contractors and bid process to source out additional contractor resources where required (see Table 2.5.2.1 for estimated costs).

1.1.4 Leave to Construct

Not applicable.

1.2 Chatham-Kent Rural Expansion Project (AMP ID 854)

In order to provide opportunities for economic growth within Chatham-Kent, Union is proposing to install both a 500 metre (m) NPS 12 steel 6,040 kPa and a 13 km NPS 8 steel 6,040 kPa pipeline to boost system capacity across the Chatham-Kent region.

The Chatham East Pipeline and the Sarnia South Pipeline feed the majority of customers across the Chatham-Kent region. The Chatham-Kent Rural Expansion (CKRE) Project will reinforce both of these systems, providing much needed capacity to numerous communities across Chatham-Kent.

Pressures along the Chatham East Pipeline are expected to reach minimums in 2019/2020, while the Sarnia South Pipeline is already at its maximum capacity.

If not completed, there is a risk of falling below minimum pressures along the Chatham East Pipeline in 2019/2020, while also not being able to accommodate any significant growth on the entire Chatham-Kent system.

The benefit of this project is that it will serve a significant number of years of regular rate growth while also providing opportunities for large commercial, industrial and greenhouse customers to expand current operations or to build new sites within Chatham-Kent.

1.2.1 Scope

The project scope includes:

- Installation of 500 m of NPS 12 steel pipe designed to 6,040 kPa along Bear Line Road from the Dover Valve Site to Dover Centre Station.
- Installation of 13 km of NPS 8 steel pipe designed to 6,040 kPa along Kent Bridge Line from the Simpson Road Valve Site to a new station to be located at Kent Bridge Line and Base Line Road.

The following alternatives are to be evaluated:

- Installing a different diameter pipeline.
- Running a new lateral from the Panhandle to support the Chatham East Pipeline.
- Joining two previously independent distribution systems.
- Obtaining supply from nearby non-Union pipelines.
- Looping pipe in a different location.
- Implementing demand side management.

The project construction is estimated to start in 2019.

1.2.2 Expenditures

The total cost is $19.1 million.

1.2.3 Leave to Construct

A leave to construct has already been filed with the Ontario Energy Board (OEB).

1.3 Compressed Natural Gas (CNG) Project (AMP ID 1439, 859)

1.3.1 Scope

Non-regulated

Union's Highway 401 Compressed Natural Gas (CNG) project will establish key heavy-duty truck CNG refuelling infrastructure on Canada's busiest trucking corridor. It will be accomplished in conjunction with leading, Canadian industry providers of CNG solutions. The project scope will encompass all aspects of engineering, approvals, procurement, construction, commissioning, and ongoing operation and maintenance of three refueling stations at strategic locations along the Highway 401 corridor including Windsor, London and Napanee in Eastern Ontario.

The objective of this project is to provide the reliability and attractive pricing that is critical for the many fleets that regularly use the Highway 401 corridor to make long-term CNG adoption decisions for their operations. Growing CNG penetration in Ontario is strategically significant as it allows Union to grow natural gas consumption while simultaneously reducing Ontario's greenhouse gas (GHG) emissions.

Moving forward with this project will allow Union to leverage federal government incentive funding and our early mover advantage.

Regulated

Construction and operation of new CNG fueling stations by third parties is also expected to occur and Union will need to provide the gas distribution facilities (e.g., main, service, and meter stations) required to supply these CNG stations. The price of competing diesel fuel and availability of government incentive programs will be critical factors underpinning growth in this sector.

1.3.2 Expenditures

Non-regulated

Union will build three stations at an estimated cost of $9 million in 2018. $3 million of this will be funded by an interest free, forgivable loan from Natural Resources Canada.

Regulated

2018	3 stations	$1.1 million
2019	7 stations	$1 million
2020	6 stations	$2.3 million
2021	5 stations	$1.9 million
2022	5 stations	$1.9 million

1.3.3 Resources

Non-regulated

Union will use third party contractors to design, build, operate and maintain the three new stations.

Regulated

Union will use internal resources for design and our alliance partners for construction.

1.3.4 Leave to Construct

Non-regulated

Leave to Construct is not required.

Regulated

Leave to construct is not anticipated for any of these projects as they are relatively small in size.

1.4 Dunnville Transmission Reinforcement Project (AMP ID 1202)

Due to in-franchise growth on the Eastern Transmission System, inlet pressures into Rymer Road Station (12Z-301) will reach minimums in 2021 on a design heating degree day (35 DD ION). Pressures are expected to be below minimum inlet pressures of 700 kPa into Rymer Road Station on a design day.

To meet minimum inlets into Rymer Road Station, reinforcement is required on the Eastern Transmission System between the outlet of Caledonia Trans and Dunnville.

If not completed, there is a risk that falling below minimum pressures at Rymer Road Station will result in this station not being able to serve customers downstream. This station is the only feed into the city of Dunnville.

1.4.1 Scope

This reinforcement will install 8.4 km of NPS 10 steel
1,900 kPa main from the outlet of Caledonia Transmission Station and end at Stoneman Road.

The benefit of the project is that it will support more than eight years of in-franchise growth on the Dunnville Distribution System based on forecasted growth.

The project construction will start in 2021.

Alternatives will be evaluated in 2019.

1.4.2 Expenditures

The total cost is $11 million.

1.4.3 Leave to Construct

This project requires application in 2020.

1.5 Greenstone Gold Mine Project (AMP ID 848)

Greenstone Mine is an open-pit gold mine (brownfield site) with up to 30,000 tpd processing, recovering gold using cyanide recovery methods. The mine has a fifteen-year life. Natural gas access to the Greenstone Gold Mine is required to accommodate mine expansion. Mine expansion is not possible without this infrastructure expenditure.

1.5.1 Scope

Union will install a dedicated high-pressure line from the TransCanada Pipeline (TCPL) to the Greenstone Gold sales meter station. The project will include:

- 14 km of NPS 6 pipe installed along Hwy 584, through the town of Geraldton and continuing along Old Arena Road to the customer station location. The route is based on verbal approval from the municipality.
- Customer delivery request of 11,000 m^3/hr for operations (including Cogen).
- Minimum Gauge Pressure of 2,757 kPa (400 psi).
- The project assumes using existing TCPL tap, but potential TCPL tap modification may be required (not included in current cost estimate).

The project construction will start in spring 2020 and be in service by May 2021.

1.5.2 Expenditures

The construction cost estimate is $28.5 million with $25.5 million for Aid to Construct.

1.5.3 Resources

The majority of the work will be done by a contractor.

1.5.4 Leave to Construct

This project requires application in September 2019.

1.6 Guelph Transmission Reinforcement Project (AMP ID 1201)

Due to in-franchise growth on the Guelph Transmission System, pressures into Puslinch Transmission Station (19V-401) will reach minimums in 2027 on a design heating degree day (43.1 DD). Pressures are expected to be below minimum inlet pressures of 3,700 kPa into Puslinch Transmission station on a design day.

Reinforcement of the Guelph Transmission System between the Dawn-Trafalgar Guelph Takeoff and Puslinch Transmission Station is required.

If not completed, there is a risk that falling below minimum pressures at Puslinch Transmission Station will result in this station not being able to serve customers downstream. This station is the only feed into the entire city of Guelph.

1.6.1 Scope

This reinforcement will loop the existing NPS 10 main between the end of the previous looping (43.450628, -80.210186) to Puslinch Transmission Station. This will be approximately 4 km of NPS 12 steel pipe, 6,160 kPa along the existing road allowance.

The benefit of this project is that 40+ years of in-franchise growth can be added to the system.

The project construction will start in 2027.

Alternatives will be evaluated in 2025.

1.6.2 Expenditures

The total cost is $9.7 million.

1.6.3 Leave to Construct

This project will require application in 2026.

1.7 Hamilton Gate Station Refurbishment Project (AMP ID 2304, 2353)

The Hamilton Gate Station Refurbishment Project is a maintenance project, driven primarily by the condition of existing assets at both Hamilton Gate #1 (17X-401) and Hamilton Gate #2 (17X-402). As the two major feeds into the Hamilton District Distribution System, it is imperative that these stations be maintained to ensure safe and reliable operations in the future.

In addition to maintenance drivers, growth interests in the Hamilton District Distribution System serve to reinforce the need for refurbishing equipment at both Hamilton Gate Stations. These stations are projected to reach capacity in 2022, after which the flow throughput through each station will need to be increased and the outlet pressure from Hamilton Gate #1 will need to be increased to 1,830 kPa to defer downstream pipeline looping requirements.

1.7.1 Scope

In 2019, maintenance activities to support operation of Hamilton Gate #2 until refurbishment will include replacement of a boiler and the steel platforms providing access to the heat exchangers. Engineering assessments of the building, piping and heat exchanger will also be conducted at this time.

The Hamilton Gate Station Refurbishment Project is a partial rebuild at both Gate #1 and Gate #2 scheduled to be completed in 2022.

It will begin with refurbishing equipment at Hamilton Gate #2 in Summer 2021. This will be accomplished by:

- De-energizing Hamilton Gate #2
- Demolishing the existing transmitter and storage building (existing building is infested with rodents and its foundation is compromised due to frost heave)
- Rebuilding Gate #2 station inlet and replacing existing filter (to increase capacity)
- Demolishing and replacing existing boiler building, boilers, and boiler control system
- Installing new remote terminal unit (RTU) and telemetry equipment specific to Hamilton Gate #2

NOTE: *During the Summer 2021 construction window, Hamilton Gate #1 will feed both Gate #1 and Gate #2 station outlets (i.e. the Downtown feed and the Mountain feed). Hamilton Gate #3 will serve as a backup feed to the Hamilton loop in the event we the construction window needs to extend into Fall 2021.*

After completing refurbishment work at Hamilton Gate #2, the partial rebuild scope at Hamilton Gate #1 will commence in 2022 by:

- Completing induced AC mitigation study for the entire Hamilton Gate Station site
- De-energizing Hamilton Gate #1
- Demolishing old buildings on site including the regulator building, boiler building, RTU building (some of which were built with asbestos containing materials)
- Demolishing existing station equipment and associated piping including heat exchangers, boilers, regulation, and D/S orifice metering
- Remediating mercury impacted soil on site
- Installing new U/S metering, heat exchanger, and regulation

- Installing new heating system including new boiler buildings, boilers and associated control system
- Installing new telemetry equipment and RTU building specific to Hamilton Gate #1

NOTE: *During the Summer 2022 construction window, Hamilton Gate #2 will feed both Gate #1 and Gate #2 station outlets (i.e. the Downtown feed and the Mountain feed. Hamilton Gate #3 will serve as a backup feed to the Hamilton loop in the event the construction window needs to extend into Fall 2022.*

1.7.2 Expenditures

Total capital expenditure for this project is $23 million (magnitude level estimate, w/ +50 per cent/-25 per cent range ability). This estimate is split between:

- $1.9 million in 2019 for maintenance and engineering assessments.
- $7 million in 2021 for refurbishment scope at Hamilton Gate #2.
- $20 million in 2022 for refurbishment scope at Hamilton Gate #1.

1.7.3 Resources

A project of this magnitude is traditionally designed and constructed by Union's Major Projects department. The construction work will be managed by Major Projects and an approved contractor will execute the work. Depending on the scope, the construction contractor resourcing will be managed through a combination of existing Alliance contractors and a bid process to source out additional contractor resources where required.

1.7.4 Leave to Construct

Not applicable.

1.1 Hensall/ Goderich Transmission Reinforcement Project (AMP ID 2376)

Due to in-franchise growth on the Hensall Transmission System, inlet pressures into Northern Cross Customer Station (23N-201C) will reach minimums in 2026 on a design heating degree day (43.1 DD IOFF). Due to the undersized NPS 8 Goderich Line, low inlet pressures are expected into the Northern Cross Customer Station on a design day.

Reinforcement is required to supply adequate gas volumes to existing customers in the Forest, Hensall and Goderich regions. To meet minimum inlets into the Northern Cross Customer Station, reinforcement is required on the Hensall Transmission System along the NPS 8 Goderich Line.

If not completed, there is a risk that falling below minimum pressures at the Northern Cross Customer Station will result in this station not being able to hold its required outlet pressure in flow, resulting in Union being unable to meet established customer demands.

1.1.1 Scope

This reinforcement will install 11.4 km of NPS 10 steel 3,450 kPa MOP main to loop the existing NPS 8 Goderich Line from Hensall Road to Sanctuary Line. This looping project will run along Huron Road (Highway 8).

The benefit of this project is that it will support up to eight years of in-franchise growth on the Forest, Hensall and Goderich System based on forecasted growth, provided other areas of the system remain above minimum inlet pressures.

The project construction will start in 2026.

Alternatives are to be evaluated in 2024.

1.1.2 Expenditures

The total cost is $25 million.

2024	$67.3 thousand
2025	$2.2 million
2026	$21.7 million
2027	$1 million

1.1.3 Leave to Construct

This project will require application in 2025.

1.1 Hensall Transmission Station Rebuild Project (AMP ID 2409)

Presently, the Hensall Transmission Station is not able to supply gas at a high enough pressure. This station is not fully using the available capacity of the pipeline downstream as it supplies gas at a pressure significantly lower than the MOP. As a result, the Hensall Transmission System is not able to maximize the effectiveness of the existing pipeline infrastructure. Without a station rebuild, Hensall Transmission System will fail to maintain minimum inlet pressures into the Northern Cross Customer Station during the winter of 2023 on a design day (43.1DD IOFF). A rebuild of the Hensall Transmission Station (14N-302) is required to increase capacity and maximum sustainable outlet pressure.

The benefit of this project is that it will support in-franchise growth on the Hensall Transmission System, supporting growth in the areas of Forest, Hensall and Goderich. If not completed, there is a risk that the Hensall Transmission System will be unable to meet design day flows to existing customers.

1.1.1 Scope

A rebuild of the Hensall Transmission Station (14N-302) is required to increase capacity and maximum sustainable outlet pressure.

To meet system demands on the Hensall Transmission System and to defer pipeline reinforcement along the NPS 8 Goderich Line, this station rebuild will defer an 11.4 km pipeline project by three years.

The project construction will start in 2023.

Alternatives are to be evaluated in 2021 and 2022.

1.1.2 Expenditures

The total cost is $2 million.

1.1.3 Resources

The project will be completed by contractors with minor support from internal district resources.

1.1.4 Leave to Construct

Not Applicable.

1.1 Ingersoll Transmission Station Rebuild Project (AMP ID 2400)

Due to in-franchise growth on the Eastern Transmission System, flows through Ingersoll Transmission Station (14R-102) will exceed the station's capacity in 2024 on design day.

To meet system demands on Eastern Transmission, Ingersoll Transmission station must be rebuilt to provide adequate capacity on a design day.

If not completed, there is a risk that the station will not be able to handle the projected flows, and will not be able to meet the demands of downstream customers.

1.1.1 Scope

The Ingersoll Transmission Station will be rebuilt with construction starting in 2024.

The benefit of this project is that it will support in-franchise growth on the Eastern Transmission System serving communities like Tillsonburg and Woodstock.

Alternatives are to be evaluated in 2022.

1.1.2 Expenditures

The total cost is $16 million.

1.1.3 Leave to Construct

This project will require application in 2023.

1.2 Kingsville Transmission Reinforcement Project (KTRP) (AMP ID 1550, 1494, 1551, 1552, 857)

1.2.1 Scope

This project consists of the installation of an approximately 19 km NPS 20 pipeline from an interconnect at the existing NPS 20 Panhandle Line in the Town of Lakeshore to a new station in the Town of Kingsville. Full details of the project are available in Union's pre-filed evidence for Ontario Energy Board Application EB-2018-0013.

1.2.2 Expenditures

The total expenditure for this project is approximately $103.9 million from 2017 to 2020. The cost for this project is based on a pre-budget estimate.

1.2.3 Resources

This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

1.2.4 Leave to Construct

Union has filed a Leave to Construct application with the Ontario Energy Board for this project: EB-2018-0013.

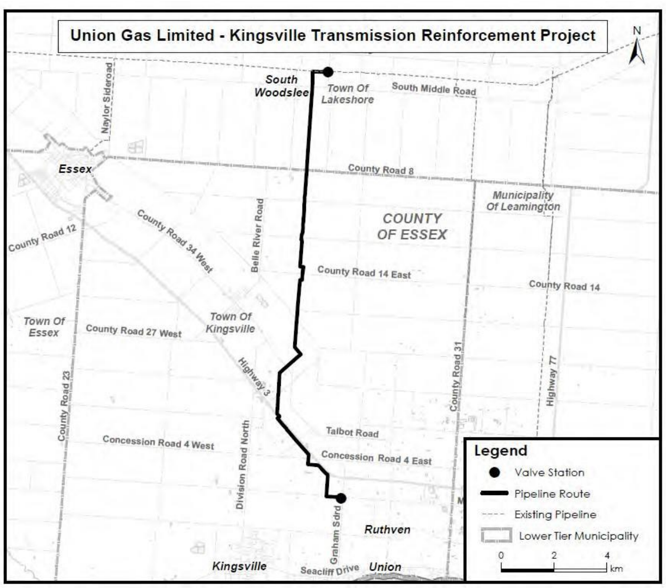


Figure 1.2.1.1: Proposed pipeline route

1.3 Owen Sound Transmission Reinforcement Project (AMP ID 2375)

Due to in-franchise growth on the Owen Sound Transmission System, pressures into Port Elgin Transmission Station (29N-101) will reach minimums in 2025 on a design heating degree day (43.1 DD). Pressures are expected to be below minimum inlet pressures of 860 kPa into Port Elgin Transmission station on a design day.

Reinforcement of the Owen Sound Transmission System is required between Teviotdale Transmission (23R-601) and Durham Gate (27R-401).

If not completed, falling below minimum pressures at Port Elgin Transmission Station will result in this station not being able to serve customers downstream in Port Elgin.

1.3.1 Scope

This reinforcement will lift the existing NPS 8 steel and lay
28,800 m NPS 16 steel pipeline at 4,670 kPa MOP. Installation will be along the easement between 43.930813, -80.761340 (approximately Highway 6 and Sideroad 3) and Durham Transmission Station.

The benefit of the project is that five years' in-franchise growth can be added to the system.

The project construction will start in 2025.

Alternatives will be evaluated in 2023.

1.3.2 Expenditures

The total cost is $51.9 million.

1.3.3 Leave to Construct

Requires application in 2024.

1.4 Owen Sound Transmission Reinforcement Project (AMP ID 863)

Due to in-franchise growth on the Owen Sound Transmission System, as well as the addition of the new EPCOR customer serving the Southern Bruce Communities, pressures into Port Elgin Transmission Station (29N-101) will reach minimums in 2019 on a design heating degree day (43.1 DD). Pressures are expected to be below minimum inlet pressures of 860 kPa into Port Elgin Transmission station on a design day. Reinforcement of the Owen Sound Transmission System is required between Durham Gate (27R-401) and Owen Sound Transmission Station (31Q-501).

If not completed, falling below minimum pressures at Port Elgin Transmission Station will result in this station not being able to serve customers downstream in Port Elgin.

1.4.1 Scope

This reinforcement will loop the existing NPS 10 steel pipeline with another 34,200 m NPS 12 steel pipeline at 4,670 kPa maximum operating pressure (MOP). Installation will be along the road allowance between Durham Gate station and Owen Sound Transmission Station.

The benefit of the project is that an EPCOR customer is added plus five years' in-franchise growth can be added to the system.

The project construction will start in 2019.

1.4.2 Alternatives Evaluated

- MOP upgrade of upstream portion of Owen Sound Transmission System
- Installing compression.

Both alternatives were rejected as they were too costly.

1.4.3 Expenditures

The total cost is $58 million (pending project funding approval). Current approved cost is $51 million in 2019 and $898 thousand in 2020.

Note: *Discussions with EPCOR are ongoing, with the timing of the project subject to finalization of contracts and confirmation of requirements.*

1.4.4 Leave to Construct

Requires application in 2018.

1.5 Oxford Transmission Reinforcement Project (AMP ID 2374)

Due to in-franchise growth on the Eastern Transmission System, inlet pressures into Delhi Transmission Station (12T-201) will reach minimums in 2023 on a design heating degree day (35 DD ION). Low inlet pressures are expected into Delhi Transmission Road Station which causes low inlet pressures into Simcoe North. As a result, this causes the system to not meet minimum inlet pressures (1,150 kPa) into Port Dover South station on a design day.

To meet minimum inlets into Delhi Transmission Station, reinforcement is required on the Eastern Transmission System between the end of Oxford Phase 1 reinforcement and Delhi Transmission Station.

If not completed, falling below minimum pressures at Delhi Transmission Station will result in this station not being able to hold its required outlet in order to maintain minimum inlets and serve customers downstream.

1.5.1 Scope

This reinforcement will involve the installation of 2.8 km of NPS 8 steel 4,960 kPa main from the end of Oxford Reinforcement Phase 1 to Delhi Transmission Station.

The benefit of the project is that it will support in-franchise growth on the Simcoe and Port Dover Distribution Systems based on forecasted growth.

The project construction will start in 2023.

Alternatives are to be evaluated in 2021.

1.5.2 Expenditures

The total cost is $7.2 million.

2021	$20 thousand
2022	$624 thousand
2023	$6.3 million
2024	$302 thousand

1.5.3 Leave to Construct

This project requires application in 2022.

1.6 Oxford Gate Station Rebuild Project (AMP ID 2408)

Due to in-franchise growth on the Eastern Transmission System, flows through Oxford Gate Station will exceed the station's capacity in 2020 on design day.

To meet System demands on Eastern Transmission, Oxford Gate station (15S-301) needs to be rebuilt to provide adequate capacity.

If not completed, there is a risk that the station will not be able to handle the projected flows, and will not be able to meet the demands of downstream customers on design day.

1.6.1 Scope

Oxford Gate Station will be rebuilt.

The benefit of this project is that it will support in-franchise growth on the Eastern Transmission System serving communities like Paris and Simcoe.

The project construction will start in 2020.

Alternatives are to be evaluated in 2018 and 2019.

1.6.2 Expenditures

The total cost is $1 million.

1.6.3 Resources

The project will be completed by contractors with minor support from internal district resources.

1.6.4 Leave to Construct

Not Applicable.

1.7 Panhandle Transmission System Reinforcement Project (AMP ID 2355)

The Panhandle Transmission System is composed of two pipelines: NPS 16/20) and NPS 20/36 extending from Dawn to the Ojibway Interconnect along with four laterals (into the Leamington/Kingsville market) and the Sandwich compression facility located near Windsor. The System can also transport volumes received at the Ojibway Interconnect back to Dawn.

In addition to serving typical residential, commercial and industrial customers, the Panhandle Transmission System also supplies four large power generation plants and a number of greenhouses in the Chatham-Kent and Leamington/Kingsville areas.

Based on the current forecast for in-franchise general service and contract growth in the Panhandle Transmission System market, Union has identified the need to reinforce the Panhandle Transmission System for the 2026 to 2027 winter operating season.

1.7.1 Scope

Union proposes to extend the NPS 36 pipeline an additional 14 km from the Dover Transmission Station towards the Comber Transmission Station paralleling the existing NPS 20 Panhandle.

The project will consist of planning and engineering to commence in 2024, with construction to begin in 2026.

1.7.2 Expenditures

The total expenditure for this project is approximately $112.6 million from 2024 to 2027. The cost for this project is based on a magnitude estimate.

1.7.3 Resources

This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

1.7.4 Leave to Construct

This project will require a Leave to Construct application to be filed with the Ontario Energy Board.

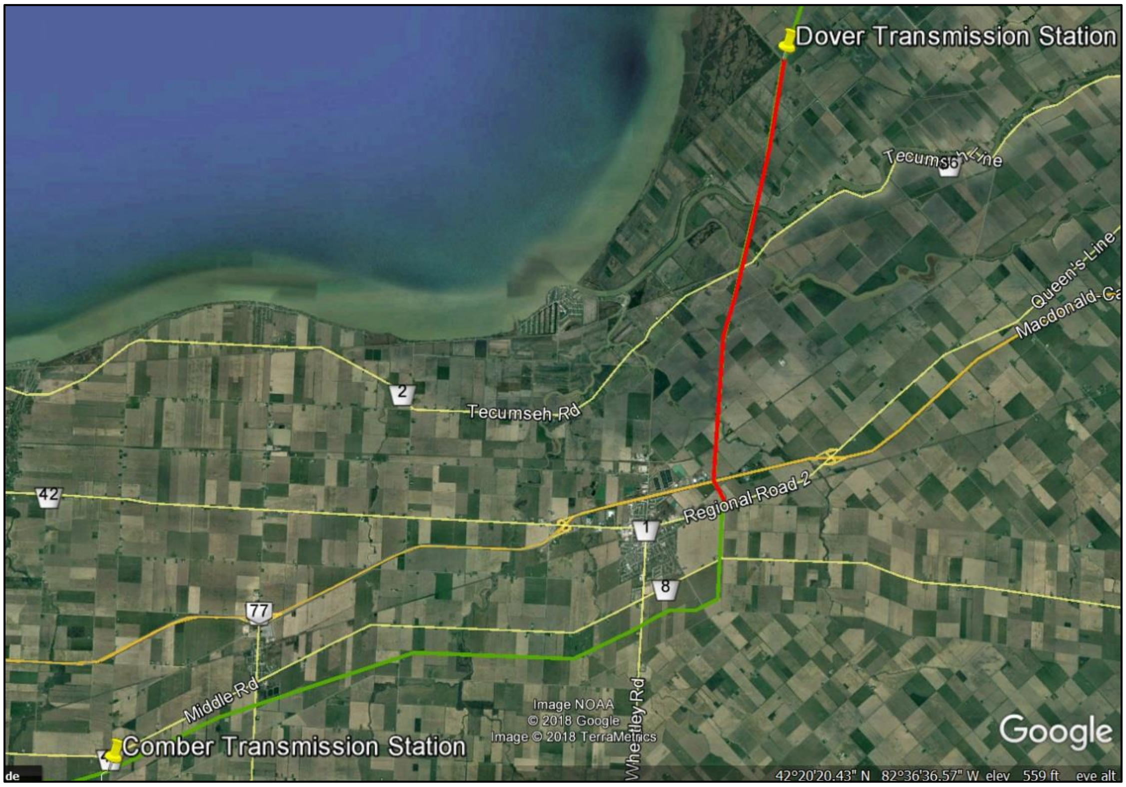


Figure 1.7.1.1: Proposed pipeline route

1.8 Parry Sound Reinforcement Phase 1 Project (AMP ID 1660)

Due to in-franchise growth on the Parry Sound Distribution System (420 kPa MOP), it is expected that system pressures at the inlet of Parry Sound Town Border Station (TBS) (44801002) will go below the required minimum in winter 2023 on a design heating degree day (49.3 DD). Pressures are expected to be below 1,900 kPa which is the minimum inlet required at Parry Sound TBS (44801002) in winter 2023 on a design day.

Reinforcement of the Parry Sound Distribution System (4,965 kPa MOP) downstream of Elmsdale CMS (44801001) is required. This will increase pressures observed at the inlet of Parry Sound TBS (44801002) and will provide approximately four years of in-franchise growth before Reinforcement Phase II.

If not completed, there is a risk that failing to meet minimum inlet at Parry Sound TBS in winter 2023 could result in customer loss on design day. No alternate feeds are available in the region to accommodate the load.

1.8.1 Scope

This reinforcement will loop the existing NPS 4 steel pipeline with another 12,500 m NPS 6 steel pipeline at 6,895/4,965 kPa MOP. Installation will occur along Hwy 518/Seguin Trail in Sprucedale region from the end of the existing NPS 6 pipeline to the intersection of Seguin Trail and John St.

The benefit of this project is that it will support four years of in-franchise growth on the Parry Sound Distribution System based on forecasted growth.

The project construction will start in 2023.

Alternatives are to be evaluated in 2021.

1.8.2 Expenditures

The total cost is $15 million.

1.8.3 Leave to Construct

Requires application in 2022.

1.9 Parry Sound Reinforcement Phase 2 Project (AMP ID1765)

Due to in-franchise growth on the Parry Sound Distribution System (420 kPa MOP). It is expected that System pressures at the inlet of Parry Sound TBS (44801002) will go below the required minimum in winter 2027 on a design heating degree day (49.3DD). Pressures are expected to be below 1,900 kPa which is the minimum inlet required at Parry Sound TBS (44801002) in winter 2027 on a design day.

Reinforcement of the Parry Sound Distribution System (4,965 kPa MOP) downstream of Elmsdale CMS (44801001) is required. This will increase pressures observed at the inlet of Parry Sound TBS (44801002) and will provide approximately five years of in-franchise growth.

If not completed, there is a risk that failing to meet minimum inlet at Parry Sound TBS (44801002) in winter 2027 could result in customer loss on design day. No alternate feeds are available in the region to accommodate the load.

1.9.1 Scope

This reinforcement will loop the existing NPS 4 steel pipeline with another 19,000 m NPS 6 steel pipeline at 6,895/4,965 kPa MOP. Installation will occur along Highway 518/Seguin Trail in Sprucedale region from the end of Phase I NPS 6 loop to Highway 518 close to Orville PRS.

The benefit of this project is that it will support five years of in-franchise growth on the Parry Sound Distribution System based on forecasted growth.

The project construction will start in 2027.

Alternatives are to be evaluated in 2026.

1.9.2 Expenditures

The total cost is $20 million.

1.9.3 Leave to Construct

This project will require application in 2026.

1.10 Sarnia Industrial Line System Expansion Project (AMP ID 884, 1560, 1561, 1562, 1563, 1199)

The Sarnia Industrial Line system is comprised of a series of parallel pipelines: NPS 10 NPS 12, NPS 16 and NPS 20. The system starts at the Vector Courtright and Great Lakes Courtright stations in St. Clair Township and extends to the Churchill Road Station in Sarnia. The system is also connected to the Dawn Compressor Station.

The NPS 12 runs the entire distance between the Courtright stations and the Sarnia Industrial Station. The NPS 20 runs the majority of the way from the Courtright stations to the Dow Valve Site. The NPS 16 runs between the Novacor Corunna station and the Dow Valve Site. The NPS 10 runs between the Dow Valve Site and the Churchill Road Station.

The Sarnia Industrial Line system is also connected to Dawn from the NPS 20 Payne to Sarnia pipeline between Payne Pool station and the Novacor Corunna station, and through the NPS 8 Dawn Kimball and NPS 10 Payne Kimball pipelines.

The Sarnia Industrial Line system was last expanded in 2015 under filing EB-2014-0333, the Sarnia Expansion Pipeline Project.

1.10.1 Scope

Union has identified the need for system reinforcement to serve forecasted industrial contract rate growth in the Sarnia market. This proposed project consists of system reinforcement from the Dow Valve Site to the Churchill Road Station.

Pipeline routes are being evaluated to identify a preferred running line. The length of the pipeline routes being considered vary from approximately 4.5 to 7.0 kilometers.

The project will consist of planning and engineering to commence in 2018, with construction to begin in 2020.

1.10.2 Expenditures

The total expenditure for this project is approximately $64.8 million from 2018 to 2021. The cost for this project is based on a magnitude estimate.

1.10.3 Resources

This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

1.10.4 Leave to Construct

This project will require a Leave to Construct application to be filed with the Ontario Energy Board.

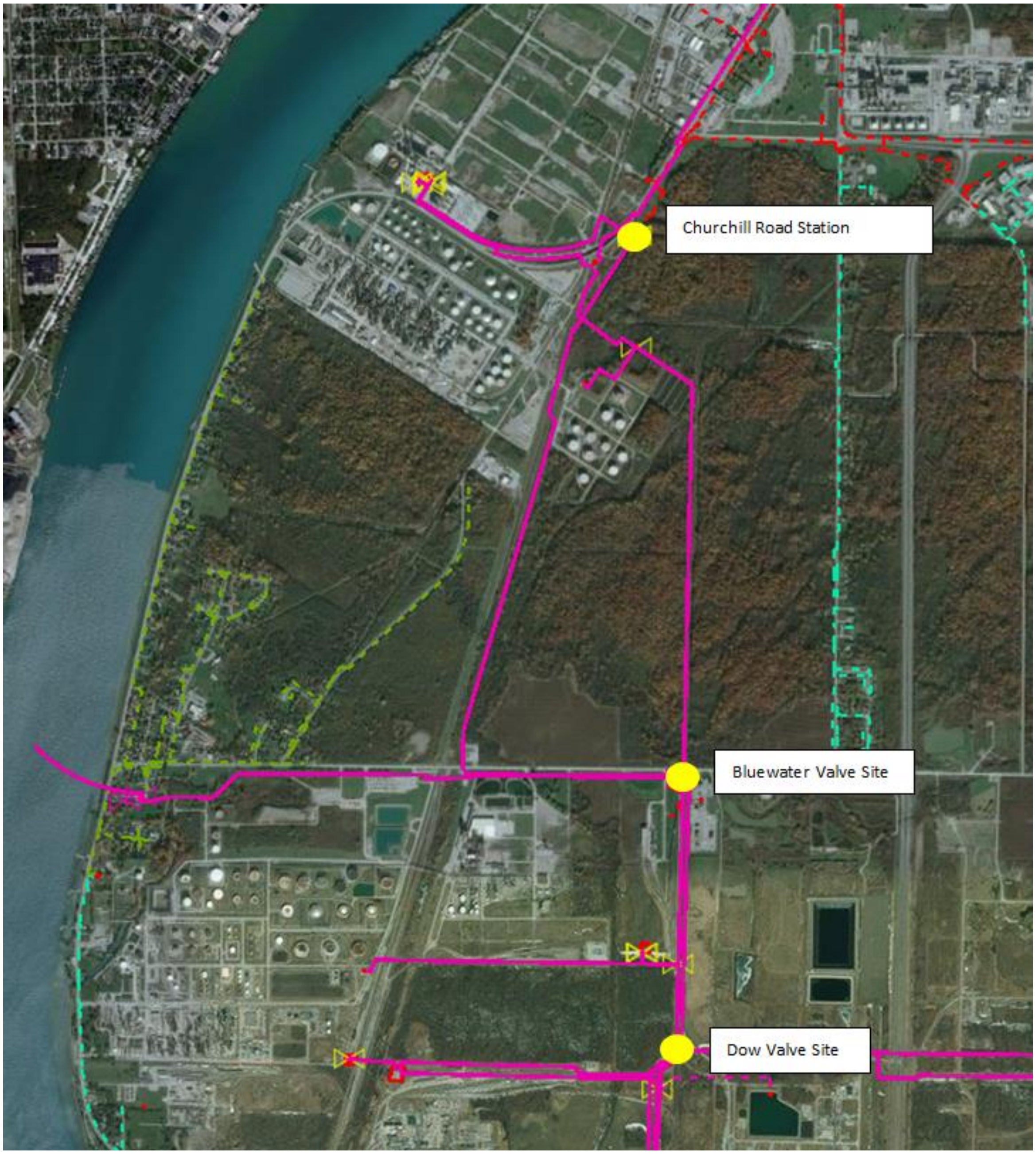


Figure 1.10.1.1: Overview of the Sarnia Industrial Line system Expansion Project area

1.11 Stratford Reinforcement Project (AMP ID 1558)

Due to in-franchise growth on the Hensall Transmission System, inlet pressures into Northern Cross Customer Station (23N-201C) will reach minimums in 2018 on a design heating degree day (43.1 DD IOFF). Due to the undersized NPS 8 Stratford Line, low inlet pressures are expected into Stratford Gate Station, which in turn causes low inlet pressures into the Northern Cross Customer Station (23N-201C) on a design day. This issue is being mitigated by temporarily relying on increased pressures available along the Dawn to Parkway System to get through winter 2018/2019.

To meet minimum inlets into the Northern Cross Customer Station (23N-201C), reinforcement is required on the Hensall Transmission System along the NPS 8 Stratford Line.

If not completed, there is a risk that falling below minimum pressures at the Northern Cross Customer Station (23N-201C) will result in this station not being able to hold its required outlet pressure in flow, resulting in Union being unable to meet established customer demands.

1.11.1 Scope

This reinforcement will install 10.8 km of NPS 12 steel 6,160 kPa MOP steel main to loop the existing NPS 8 Stratford Transmission Line from Beachville Transmission Station toward the City of Stratford, through Oxford County in Zorra Township. This looping project will run along 41st Line to Perth-Oxford Rd.

The benefit of the project is that it will support up to eight years of in-franchise growth on the Forest, Hensall and Goderich System based on forecasted growth.

The project construction will start in 2019.

1.11.2 Alternatives Evaluated

- Install 7.6 km of NPS 12 steel main (6,160 kPa) from the Beachville Takeoff to Road 96 in Zorra Township. This option was rejected as it does not provide five years of organic growth on the Hensall Transmission System.
- Install compression on the Stratford Line. This option was rejected due to high initial and operating costs.
- Looping the NPS 8 Goderich Line. This option was rejected as a significantly longer reinforcement was required in order to compensate for the undersized Stratford Line.
- Carrying out an MOP upgrade on the main running out of Hensall Transmission Station. This option was rejected as it would only provide approximately three years of growth and would not likely be able to be implemented by winter 2019/2020.

1.11.3 Expenditures

The total cost is $24.8 million pending project funding approval (PFA). Current approved cost is $23 million in 2019 and $506 thousand in 2020.

1.11.4 Leave to Construct

This project will require application in 2018.

1.12 Sudbury Transmission Compressors Project (AMP ID 2397)

The Sudbury Transmission System feeds customers up to and including Espanola. With current TransCanada PipeLines (TCPL) contract pressures, the System does not have enough liquefied natural gas (LNG) storage to meet System demands in the event of a design winter. The Transmission System is currently relying on higher-than-contracted TCPL pressures at Marten River.

Installing two 2,100 horse power (HP) Compressors upstream of Coniston at Marten River takeoff is proposed to remove the dependency on higher-than-contracted pressures. This will also help accommodate in-franchise regular-rate growth.

If not completed, there is a risk that exhausting LNG storage will result in system pressures below minimum design and will affect regular rate customers and major contract customers.

1.12.1 Scope

The project involves the installation of two 2,100 HP Compressors upstream of Coniston at Marten River takeoff.

The benefit of this project is system reliability and avoided physical/reputation costs associated with an outage.

The project construction will start in 2023.

1.12.2 Alternatives Evaluated

- Higher contracted pressures from TCPL
- Lift and lay NPS 10 from North Bay with NPS 16.

1.12.3 Expenditures

The total cost is $31.2 million.

1.12.4 Leave to Construct

This project will require an application in 2022.

1.13 Sudbury Transmission Installation Project (AMP ID 2407)

The Sudbury Transmission System downstream of Coniston splits at Azilda and feeds towards Espanola and Chelmsford. System growth predicts pressures into Chelmsford to be below minimum design in 2027. The Transmission System downstream of Coniston is expected to reach capacity in 2027.

Installing a section of pipe will eliminate an NPS 6 pipe bottleneck in the system. Several sections of NPS 6 were looped in 2015 with NPS 10.

If this project is not completed, there is a risk of an inability to attach new customers.

The benefit of this project is that it will increase system capacity and support in-franchise regular rate growth.

1.13.1 Scope

The project involves installation of 1 km of NPS 10 6,895 kPa MOP pipe.

The project construction will start in 2027.

Alternate pipe sizes and locations are to be evaluated.

1.13.2 Expenditures

The total cost is $2.9 million.

1.13.3 Leave to Construct

This project will require an application in 2026.

1.1 Sudbury Transmission Twinning Project (AMP ID 2406)

The Sudbury Transmission System is twinned from Coniston to Espanola except for a 2.55 km section that was previously abandoned. The transmission System downstream of Coniston is expected to reach capacity in 2027.

Completing twinning of the system will eliminate the bottleneck (single pipe) between Coniston and Azilda. The project is proposed to increase system capacity and support in-franchise regular rate growth.

If not completed, there is a risk of an inability to attach new customers on the systems downstream.

The benefit of this project is that it will support growth and system integrity.

1.1.1 Scope

The twinning will involve 2.55 km of NPS 12 6,895 kPa MOP pipe installed in an existing easement.

The project construction will start in 2027.

Alternate pipe sizes and alternate locations are to be evaluated.

1.1.2 Expenditures

The total cost is $6.8 million

1.1.3 Leave to Construct

This project will require an application in 2026.

1.2 Tillsonburg Transmission Reinforcement Project (AMP ID 2405)

Due to in-franchise growth on the Eastern Transmission System, inlet pressures into Simcoe North Station (12U-261) will reach minimums in 2025 on a design heating degree day (35 DD ION). Low inlet pressures are expected into Simcoe North Station (12U-261), which causes the system to not meet minimum inlet pressures (1,150 kPa) into Port Dover South station on a design day.

To meet minimum inlets into Simcoe North Station, reinforcement is required on the Eastern Transmission System just upstream of Huygies Transmission Station (12T-501).

If not completed, falling below minimum pressures at Simcoe North Station (12U-261) will result in this station not being able to hold its required outlet in order to maintain minimum inlets and serve customers downstream.

1.2.1 Scope

This reinforcement will involve the installation of 10 km of NPS 8 steel 3,450 kPa main just upstream of Huygies Transmission Station (12T-501), heading east and ending at Queensway and Hillcrest.

The benefit of the project is that it will support in-franchise growth on the Tillsonburg, Simcoe and Port Dover Distribution Systems based on forecasted growth.

The project construction will start in 2026.

Alternatives are to be evaluated in 2024.

1.2.2 Expenditures

The total cost is $15.5 million.

1.2.3 Leave to Construct

This project will require application in 2025.

1.3 Windsor Mega Hospital Reinforcement Project (AMP ID 1599)

The new Windsor Mega Hospital is looking to attach a new large-contract load near County Rd. 42 and Concession Rd. 8 in Windsor. This new site will require significant reinforcement to attach the hospital and the associated residential and commercial growth forecasted for the area. Presently, there are no mains nearby large enough to support this load. The new Windsor Mega Hospital will drive pressures below the minimum design of 140 kPa on the 420 kPa Windsor Distribution System when they attach their load.

This main extension will be constructed at the customers' expense.

Reinforcement of the Windsor Distribution System (420 kPa MOP) south of the Windsor Airport is required in order to attach new regular rate and contract rate customers. This reinforcement will provide capacity for the new Mega Hospital and for approximately 17 years of forecasted growth in the local area.

If not completed, Union will not be able to attach the new contract customer and will lose growth associated with the new hospital.

1.3.1 Scope

This reinforcement will loop the existing NPS 2 plastic and NPS 4 plastic pipeline with 4,100 m of NPS 6 plastic pipeline operating at 420 kPa MOP. Installation will be along Concession Rd. 8 from a new distribution station at Provincial Rd. to Baseline Rd., then East down Baseline Rd. to Concession Rd. 9, and then North to the customer site.

The benefit of this project is that it can support a new contract and 17 years of in-franchise growth on the Windsor Distribution System based on forecasted growth in the area.

The project construction is estimated to start in 2020.

An alternative of feeding from Rhodes Dr. via Marentette station was evaluated, but it was determined that easement would not be obtainable to run through the edge of the Windsor Airport property. Feeding from Lauzon Rd., south of the EC Row was also evaluated; however, this option was rejected due to its increased length.

1.3.2 Expenditures

The total cost is $2.4 million.

1.3.3 Leave to Construct

An application will be filed when the customer formally applies for service.

2 Pipelines

2.1 Bare and Unprotected Replacement Program (AMP ID 1996)

The purpose of this program is to identify, assess, prioritize and replace all remaining bare and unprotected steel main and associated services. These assets do not have anti-corrosion coating nor do they have any external corrosion protection installed by way of sacrificial anodes or impressed current rectifiers. These assets continue to corrode year over year contributing to leakage that increases risk to the public, drives capital expenditure to remediate, and reduces the reliability of the distribution systems for which they are a part of.

The replacement of these assets will reduce risk and increase reliability in a variety of ways:

- Minimize likelihood of further leakage – reduces risk to the public and required capital to remediate leaks.
- Removal of basement meters – improved safety and removal of below grade leak paths into homes, and improved access for meter readers.
- Upgrading of services including installation of service valves providing emergency responders with easily accessible gas shutoffs.
- Installation of Excess Flow Valves to automatically terminate the flow of gas to homes in the event of service damage.
- Increase in measurement accuracy through upgrading low pressure systems to standard distribution pressure.
- Installation of system valves on new mains to facilitate isolation of smaller sized areas of customers in the event of line hits or other emergencies.

2.1.1 Scope

The Bare and Unprotected Replacement Program includes the replacement of approximately 120 kilometres (km) of pipe and associated services. These assets are spread out across a number of Districts but are primarily located within the London, Hamilton, Waterloo and Windsor districts. A significant portion of these assets are operating at low pressure and are located in built-up locations like downtown cores with wall-to-wall concrete. This can create execution challenges and project scope changes, which are managed as needed.

Bare and Unprotected Replacement Projects are individually prioritized based on a number of factors. Some of these factors are as follows:

- Leakage history.
- Pipe vintage.
- Asset condition.

- Maximum Operating Pressure.
- Pipe size.
- Proximity to areas of high consequence.

2.1.2 Expenditures

Projects are planned on a yearly basis, and Union is targeting the full replacement of all remaining bare and unprotected assets by the end of 2024. The total expenditure for this program is $60 million from the years 2019 to 2024.

2.1.3 Resources

Bare and Unprotected Replacement Projects are typically planned and executed by the Construction and Growth departments within each District. These projects are typically executed by internal company construction crews. Larger more complex projects may be executed by third party contractor resources as necessary.

2.1.4 Leave to Construct

Not applicable.

2.2 Cathodic Protection Program (AMP ID 890)

The Cathodic Protection Program consists of the annual Priority 1 and Priority 2 anode installation program, as well as the rectifier replacement program. The program is based upon the Corrosion Control Standard Operating Practice (SOP) which provides the monitoring schedule for all steel facilities and defines the criteria for Priority 1 and Priority 2 anodes based on pipe-to-soil surveys. When the applicable corrosion prevention system reaches end of life, it is required to be replaced to maintain adequate cathodic protection.

2.2.1 Scope

Within the scope of this program are steel transmission mains, steel distribution mains, and steel isolated service lines.

2.2.2 Expenditures

The costs for the program are based on current average spends per unit. Based on this methodology, the current annual cost for the anode replacement program is $6.4 million, and the rectifier replacement cost is $0.47 million. The total program cost for 2019 to 2028 is $75.4 million. Included in this total are other cathodic protection related projects such as sectionalisation work and in some cases projects to remediate shorted casings.

2.2.3 Resources

Currently the anode installation program is completed primarily with internal resources. Approximately 10 per cent of the annual installations are completed with contractor resources. The rectifier replacements are completed with local contractor resources under the direction of the local corrosion personnel.

2.2.4 Leave to Construct

Not applicable.

2.3 Class Location Program (AMP ID 173, 897)

2.3.1 Scope

Changes in class location on pipeline systems as defined in CSA Z662 – Oil and Gas Pipeline Systems, are required to be assessed and remediated as necessary as mandated by O. Reg. 210/01: Oil and Gas Pipeline Systems under the *Technical Standards and Safety Act*, 2000, S.O. 2000, C.16. At Union, class location surveys are completed, and resulting class changes are evaluated and assessed for remediation by engineering staff on an annual basis. Pipeline segments that are deemed to have undergone a legitimate class change are evaluated based on the prescribed requirements in CSA Z662; and where deficiencies are identified, one of three forms of remediation are typically undertaken to maintain compliance to regulation.

- **Pressure Test Records** – Where pressure test records are inadequate for the new class location and the execution of a new pressure test is practical, affected pipeline segments are sometimes taken out of service to undergo an updated pressure test in order to meet the new class location requirements.
- **Valve Spacing** – Where the existing valve spacing may be inadequate based on the new class location requirements, an Engineering Assessment is completed to determine valve spacing adequacy. The result of the Engineering Assessment can be either that the valve spacing is determined to be adequate and no further remediation is required, or that the spacing is in fact inadequate and the addition of valves or pipe replacement is required.
- **Design/Location Factor –** Where the existing pipeline segment design is deemed to be inadequate for the new class location, the segment is scheduled for capital replacement and a new pipeline design is completed based on the new class location designation.

Other less common forms of remediation not identified above can also be required based on the class change assessments such as depth of cover remediation and/or repairs of pipeline defects deemed no longer acceptable for the new class location.

Given that development is occurring in close proximity to Union's pipelines annually triggering class location changes, an annual budget is required in order to meet regulatory requirements. This work ensures we are compliant with the applicable codes and standards and contributes to our efforts to maintain public safety and operational safety of Union's pipeline system.

2.3.2 Expenditures

The total capital expenditure of the Class Location Program is $165.4 million from 2019 to 2028.

The year 2019 will mark the end of the first six years of the program which have been at an increased spend in order to remediate the significant number of class changes that were identified at the outset of this program.

Starting in 2020, Union foresees the level of spend to be at a sustainment level, reflecting remediation efforts of only the segments being identified year over year. As Union moves further into sustainment for this program, historical spends for sustainment years will be used to further refine the yearly capital budget for this program.

2.3.3 Resources

This program is managed with internal Engineering resources at Union and is typically executed by external contractor resources.

2.3.4 Leave to Construct

Typically, the majority of the pipeline segments requiring capital replacement do not meet the thresholds requiring an application for a Leave to Construct. However, as projects are scoped for individual segment remediation, the requirement for a Leave to Construct is evaluated on a case-by-case basis.

2.4 Distribution Operations Pipeline Blankets Program (AMP ID 907, 910, Portfolios: General Mains, Leakage)

Within Distribution Operations at Union, each District must annually budget for work that is expected to occur, but for which specific projects/assets are not yet identified. These capital expenditures are grouped into maintenance blankets. The four primary blankets for pipeline assets are for **Service Replacement**, **Municipal Replacement**, **General Mains** and **Leakage**.

2.4.1 Scope

All four of these maintenance blankets are budgeted and planned by the Construction & Growth departments within the districts. These capital expenditures can be driven by a variety of reasons such as emergencies, integrity and safety, and municipal infrastructure conflicts.

- **Service Replacement:** The purpose of the service replacement blanket is to fund the replacement of services to customers as required and identified by Distribution Operations. These replacements could be as a result of integrity and safety concerns of vintage assets, or as requested by third parties when services are in conflict with contractor or municipal projects.
- **Leakage:** The purpose of the leakage blanket is to fund the capital work required to remediate leaks as they arise throughout the year. Depending on the severity of the leak, this work could be treated as an emergency expenditure for leaks of a severe nature or planned work for leaks of a less severe nature. This work could result in replacement of leaking vintage assets or in the use of repair fittings where appropriate.
- **Municipal Replacement/Relocations:** Municipal replacement or relocations of Union's assets are required when a municipality approaches Union in order to coordinate a municipal infrastructure project where Union's plant is in conflict. These projects are typically for roadwork (e.g., construction of a roundabout) but could be as a result of bridge replacement, sewer maintenance or building construction for example. The purpose of the municipal blanket for relocations is to fund the solutions needed to address pipeline assets that are in conflict with the municipal projects. Union endeavors to avoid conflicts with all its assets but when they cannot be avoided, Union will work with each municipality within established agreements to come to a mutually agreed upon resolution. In many cases, this results in the relocation of Union's plant that is in conflict, and more specifically, the removal of existing plant and the installation of new plant to maintain service to any customers reliant on the existing plant that was in conflict. This includes size-for-size replacement of main and services.
- **General Mains**: The purpose of the general mains blanket is to fund unplanned replacements and other capital maintenance work on distribution mains where unforeseen or previously unidentified integrity issues arise throughout the year and require immediate attention. Often these issues are discovered through other

planned work where mains are excavated and exposed where anomalies are discovered requiring repairs or cut outs.

2.4.2 Expenditures

These blankets are ongoing, annual programs and the baseline estimates for the annual expenditure was calculated using historical trends for each blanket. The capital expenditures for each are as follows:

- **Service Replacements –** the total expenditure for this blanket is $47 million for years 2019 to 2028.
- **Leakage** – the total expenditure for this blanket is $40.6 million for years 2019 to 2028.
- **Municipal Replacements –** the total expenditure for this blanket is $237.8 million for years 2019 to 2028.
- **General Mains –** the total expenditure for this blanket is $35.7 million for years 2019 to 2028

2.4.3 Resources

Projects associated with the blankets are typically planned and executed by the Construction and Growth departments within each district. They are typically executed by internal company construction crews but larger projects may be resourced by third party construction crews as necessary.

2.4.4 Leave to Construct

Not applicable.

2.5 London Lines Replacement Project (AMP ID 220, 2095, 2096, 2097, 2098)

The London Lines span approximately 80 km and extend from Dawn to Byron Transmission Station (13N-501) located in the London District. The London Lines consist of two high pressure pipelines running in parallel and were once considered a major feed supplying gas to the City of London and small communities between Dawn and London. The line that is located further north is known as the London South Line and is comprised mainly of NPS10 steel coated in Barrett Enamel that was installed in 1935. The line that is located further south is known as the London Dominion Line and is comprised mainly of NPS 8 steel coated in Durnite that was installed in 1936, which was subsequently replaced in 1952.

Although the majority of the London Dominion Line was replaced in 1952, the materials used were reclaimed and refurbished steel pipe from the Windsor district with an average vintage of 1920 to 1930. The London Lines have a MOP of 1,900 kPa from Dawn to Komoka Transmission Station (13N-401). Further east, the MOP from Komoka Station to Byron Transmission Station is 1,380 kPa. Due to the vintage, the quality of steel pipe installed, and the general deteriorating conditions, the London Lines has not operated near MOP in nearly four years.

The condition of the London Lines is generally poor and indicative of a pipeline reaching end of life. Depth of cover surveys have also been completed in the past that have highlighted areas of exposed piping. There have been multiple repairs completed on the lines due to leakage, corrosion, and third party damage. In addition, there are currently multiple outstanding leaks located along these lines. Below is a summary of the pipeline risks that currently exist on the line:

- Lines largely joined using unrestrained dresser couplings.
- Depth of cover issues.
- Locations with inoperable valves.
- Several corroded aerial crossings.
- Several repaired and outstanding leaks.
- Sections of the line have been abandoned due to condition.
- Currently operating pipelines between Dawn and Komoka below MOP to mitigate leak potential.

Due to the condition and existing risks associated with the London Lines, the current proposal is to complete a full replacement of the London Lines in one phase. A single-phase approach was based on the condition, number of repaired and outstanding leaks and depth of cover issues. Project scope, costing and timing may change as additional pre-engineering is completed.

2.5.1 Scope

This project involves the replacement of the entire London Lines in one phase. The remaining 75km dual-main London Lines NPS 10 and NPS 8 main operating at 1,380kPa) will be replaced with a single NPS 8 main operating at a MOP of 3,450kPa. The replacement project will begin at Dawn and completed just south of Komoka Transmission Station. The new pipeline will use the same running line as the existing London Lines, following road allowances as much as possible. The project timeline is as follows:

- 2019 – detailed pre-engineering design.
- 2020 – completed designs, environmental assessments and OEB application filing.
- 2021 – project execution.
- 2022 – clean-up.

2.5.2 Expenditures

Project development is in the preliminary phase with a magnitude estimate of $114 million. $4 million will be allocated in 2020 for pre-engineering design, environmental assessments and file an OEB application, $107 million in 2021 for project execution, and $3 million in 2022 for cleanup. Further work is being completed to develop the expenditures and to better define the budget toward the end of 2019.

2.5.3 Resources

Project management and construction management will be completed by either Union's Engineering Construction group or Major Projects group. Engineering, environmental, lands, regulatory and procurement assessments will be completed in-house at Union. Construction will be completed by a contractor selected using the approved Union procurement models.

2.5.4 Leave to Construct

The London Lines replacement project will require an Ontario Energy Board (OEB) Filing. Union will file a Leave to Construct application with the Board in 2020 to seek approval to construct.

London Lines Replacement Scope

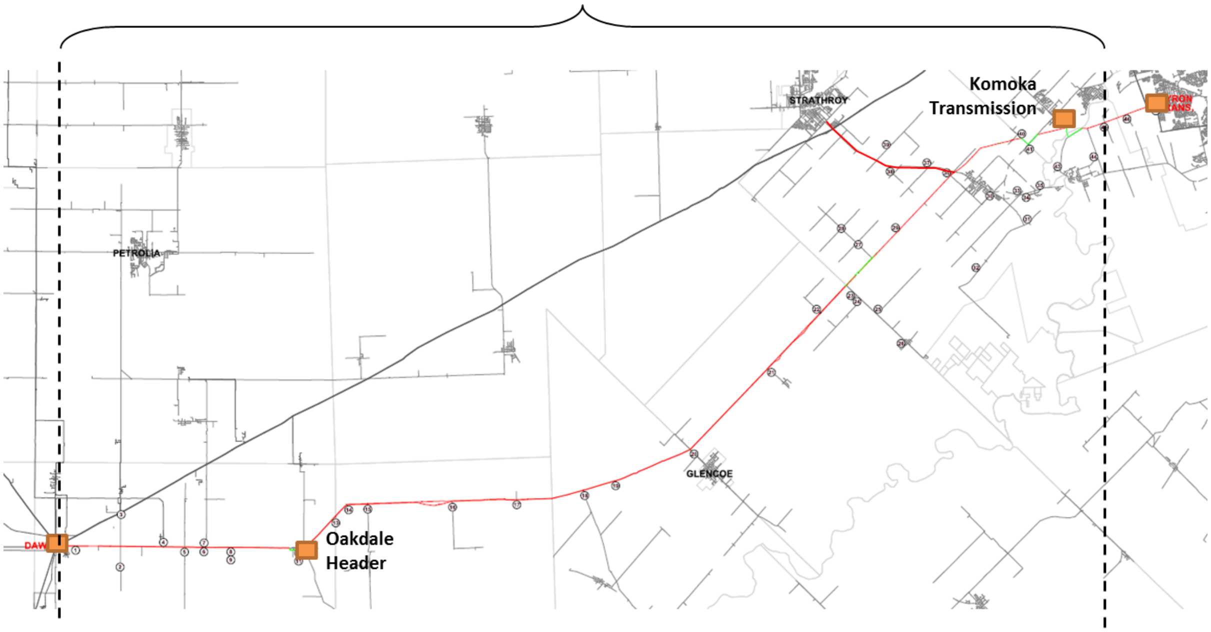


Figure 2.5.1.1: London Lines Replacement proposed project phasing

2.6 MOP Verification Program (AMP ID 906)

Maximum operating pressure (MOP) verification is the process of reviewing all existing records for a pipeline system and confirming the MOP of existing greater than 30 per cent specified minimum yield strength (SMYS) pipeline systems based upon these records. While this is not currently mandated by regulations in Canada, it is required in the United States and is expected to become a requirement in Canada in the future.

Given Union has approximately 2,980 km of pipelines greater than 30 per cent SMYS, the MOP Verification Program will be a multi-year project requiring a dedicated team. This team will be tasked with completing the verifications and determining if any pipeline remediation is required due to lack of records and/or the presence of pipe/fittings that are not properly pressure rated for the prescribed MOP of the pipeline.

The intent of the MOP Verification Program is to spread the verification work over several years to keep costs down and mitigate the need for higher expenditures in a shorter timeframe to meet these expected future mandated requirements.

2.6.1 Scope

This program will involve records review and Engineering Assessment work to verify the current MOPs of Union's greater than 30 per cent SMYS pipelines. This work is a natural progression of the existing Technical Records and Information Management efforts that have been completed at Union over the last number of years. The existing and discovered technical records will be used by engineering staff to verify that all pipelines, pipeline components and their associated material properties, including pressure test history and other relevant design and operation information, are appropriate for the current pipeline MOP. Where inconsistencies and issues arise, the need for Capital replacements in order to maintain required pipeline MOPs will be determined and executed as necessary.

2.6.2 Expenditures

The total Capital expenditure for this program is $30 million from 2023 to 2028.

Beginning in 2020, Engineering Assessments will be performed on Union's greater than 30 per cent pipeline assets to begin the MOP Verification process with respect to these assets. As this work is completed, capital dollars have been allocated beginning in 2023 to remediate issues as they arise in order to maintain the MOPs of our critical assets. As we begin to ascertain the scope of remediation required as a result of this program, the forecast of capital expenditure is expected to change.

2.6.3 Resources

Beginning in 2021, additional resources will be on boarded and are intended to be fully dedicated to this program. These resources will begin the engineering assessment work required to verify the MOPs of Union's pipelines and to scope any capital remediation requirements. Any capital remediation resulting from this work will be executed by a mix of internal resources and external contractor resources.

2.6.4 Leave to Construct

Not applicable.

2.7 Pipeline Integrity Management Programs (AMP ID 902, 175)

The Pipeline Integrity Management Program includes a systematic approach to assessing the condition, and completing the associated mitigation, on pipelines for which the stress level is at or above 30 per cent of the Specified Minimum Yield Strength (SMYS) of the pipe at its MOP, and all National Energy Board (NEB) regulated pipelines regardless of the stress level, to ensure that they are suitable for continued service. The formal program was initiated in 2002, and the baseline condition monitoring of the pipelines within the scope of the program that were installed prior to 2002 was completed by 2013, primarily through inline inspection (ILI) or External Corrosion Direct Assessment (ECDA). Work has been continuing to inspect the newer lines and to re-inspect the previously inspected lines.

The Pipeline Integrity Management Program includes approximately 2,980 km of pipe that meet the specified criteria, and includes the pipe up to and including the station inlet valve. The piping between the station inlet and outlet valve is included within the Station Integrity Management Program. The rest of the pipeline system is included within the Distribution Pipeline Integrity Management Program.

The activities associated with this work include the following three components:

- **Launchers / receivers in stations:** Install permanent ILI launcher and receiver facilities at selected Station sites where ILI runs have been identified. These programs are intended to carry on a prescribed inspection cycle and will require facilities to be available for future ILI activity.
- **Retrofitting pipeline to accommodate smart tools:** Modify pipelines to accommodate ILI tools, such as replacing reduced port valves, or bottom-out connections that prohibit the travel of ILI tools.
- **Integrity digs/mitigation:** ILI-identified defects are categorized as Immediate, Scheduled or Monitored based on Union's policy, which follows code, regulations and industry best practices.

The Distribution Pipeline Integrity Management Program includes a systematic approach to assessing the condition, and completing the associated mitigation, on pipelines for which the stress level is below 30 per cent of the SMYS of the pipe at MOP, to ensure that they are suitable for continued service. Much of this work is completed and budgeted through Distribution Operations. To supplement this work, a few targeted areas were identified within the centralized Distribution Pipeline Integrity Management Program to advance knowledge and manage risk associated with these assets.

The Distribution Pipeline Integrity Management Program includes approximately 67,440 km of mains and services within Union's pipeline system up to and including the station inlet valve that is not covered by the Pipeline Integrity Management Program. The piping between the station inlet and outlet valve is included within the Station Integrity Management Program.

2.7.1 Scope

The scope of the key activities for the greater than 30 per cent SMYS pipelines includes those activities noted earlier in this section. For the Distribution Pipelines, activities to date within scope have included advancing the assessment of legacy down plant, cased piping, and vintage plastic pipe. In 2015, Union started to complete ECDA inspections and digs on the more critical distribution lines. More focused water crossing inspections were started in 2016 and the program was further developed in 2018 and will continue for a number of years to advance the completeness of the inspection of pipelines that cross water bodies either under ground or attached to bridges.

2.7.2 Expenditures

The total capital expenditure of the Integrity Management Program is $129.6 million from 2019 to 2028.

The costs of the program were estimated using a combination of individual project estimates and historical unit costs and trends.

2.7.3 Resources

This program is managed with internal Engineering resources at Union and is typically executed by external contractor resources.

2.7.4 Leave to Construct

Typically, the majority of the pipeline segments requiring capital replacement do not meet the thresholds requiring an application for a Leave to Construct. However, as projects are scoped for individual segment remediation, the requirement for a Leave to Construct is evaluated on a case-by-case basis.

2.8 Vintage Pipe Replacement Program (AMP ID 908)

The purpose of this program is to identify, prioritize and replace critical transmission and distribution pipelines that have reached end of life and require significant capital dollars to replace.

2.8.1 Scope

There are a number of pipelines that are candidates for this program; but at this time, they have not been fully assessed and scoped for the purposes of this Asset Management Plan. As projects are further detailed, this program will be adjusted from a cost and timing perspective.

2.8.2 Expenditures

The total expenditure for this program is $75 million from the years 2019 to 2024.

2.8.3 Resources

The projects intended to be funded by this program will typically be project and construction managed by the Engineering Construction or Major Projects groups at Union. The construction execution would typically be completed by external contractor resources.

2.8.4 Leave to Construct

Most projects within this program will require Ontario Energy Board (OEB) approval/Leave to Construct applications. As projects are identified and scoped, the required applications will be filed as necessary.

2.9 Windsor Line Replacement Project (AMP ID 212, 913)

The existing 65 km Windsor Line is a distribution line operating at 1,380 kPa that runs from Windsor to Port Alma. This line, the majority of which is NPS 10, primarily serves the residential, commercial and greenhouse markets of Tilbury, Essex, Lakeshore, Comber, Leamington and Windsor. The Windsor Line can also be operated as a back feed for the Sarnia South Line and the Ridgetown Line during emergencies.

A significant portion of this line was installed in the 1930s, 1940s and 1950s and all joints prior to the 2000s were made with unrestrained mechanical couplings; portions of the older vintage pipe cannot be welded. In addition, some sections of the line cannot be isolated because of inoperable mainline valves. The Windsor Line also has sections that have poor depth of cover. Based on these integrity concerns and the significant effort and resources spent on repairing leaks on the line, the Windsor Line has been deemed a high risk and has therefore been identified as requiring replacement.

The Windsor Line will be replaced and the replacement pipeline will primarily be within road allowance with a shorter section possibly in easement. Both the services and stations will have to be upgraded for the new maximum operating pressure.

This replacement will address the integrity and operational risks with the Windsor Line and will thereby mitigate future large customer outages in the event of emergencies and necessary leak repairs, ultimately improving the overall reliability of this pipeline. The replacement will also create incremental capacity for future growth in the area.

2.9.1 Scope

The project includes the replacement of the entire Windsor Line. The existing line is a combination of NPS 10 and NPS 8 and will be replaced by an NPS 6 pipeline. The existing line operates at a pressure of 1,380 kPa and the replacement will be designed to operate at a maximum operating pressure of 3,450 kPa. The intent is to replace the existing line using the road allowance as much as possible for the new NPS 6. Approximately 650 services and 20 stations are served by the existing line which will be upgraded to the new maximum operating pressure and served by the replacement NPS 6.

Project development has started with frontend engineering design beginning in the summer of 2018 with the environmental assessment planned for 2019 and construction in 2020.

2.9.2 Expenditures

Project development is in the preliminary phase with a magnitude estimate of $88 million. Further work is being completed to develop the 2019 and 2020 expenditures and to better define the budget toward the end of 2018.

2.9.3 Resources

Project management and construction management will be completed by Union's Major Projects Group. Engineering, environment, land, regulatory and procurement will be completed in-house at Union. Construction will be completed by a contractor selected using the approved Union procurement models.

2.9.4 Leave to Construct

The scope and approval of this project is regulated by the Ontario Energy Board. Union will file a Leave to Construct application with the Board in 2019 to seek approval to construct.

The existing 65 km Windsor Line is identified in red on the map shown below.

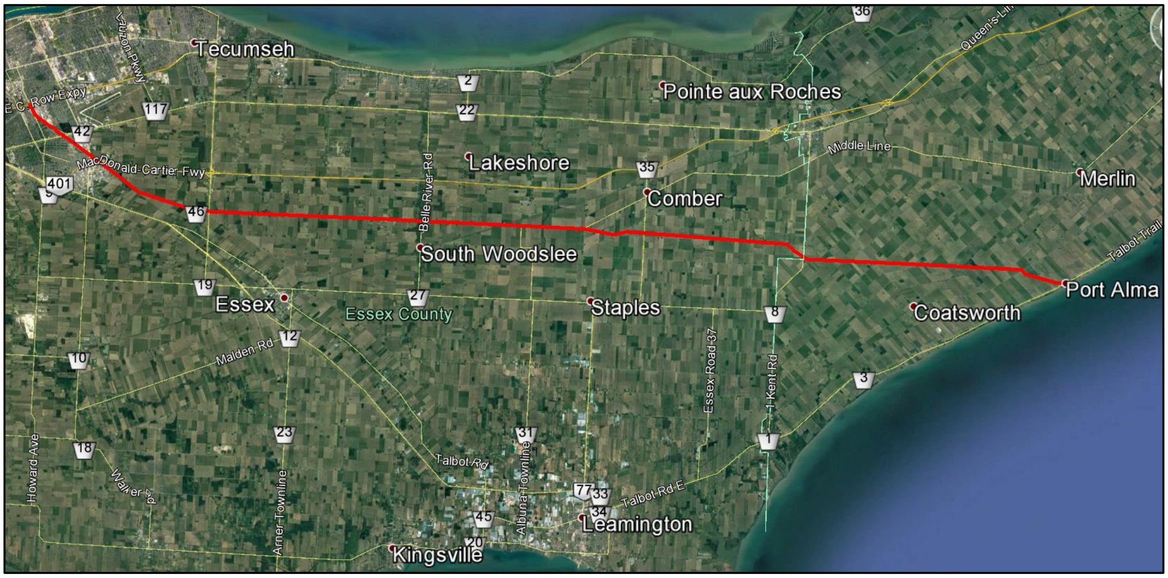


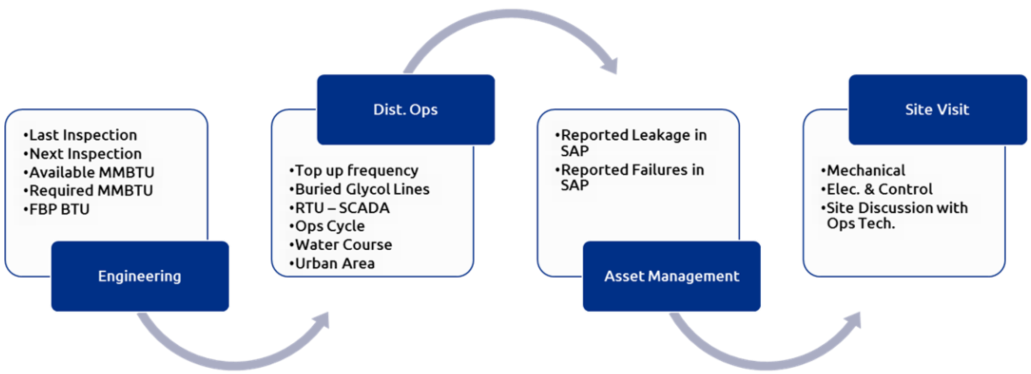
Figure 2.9.1.1: Existing Windsor Line

3 Stations

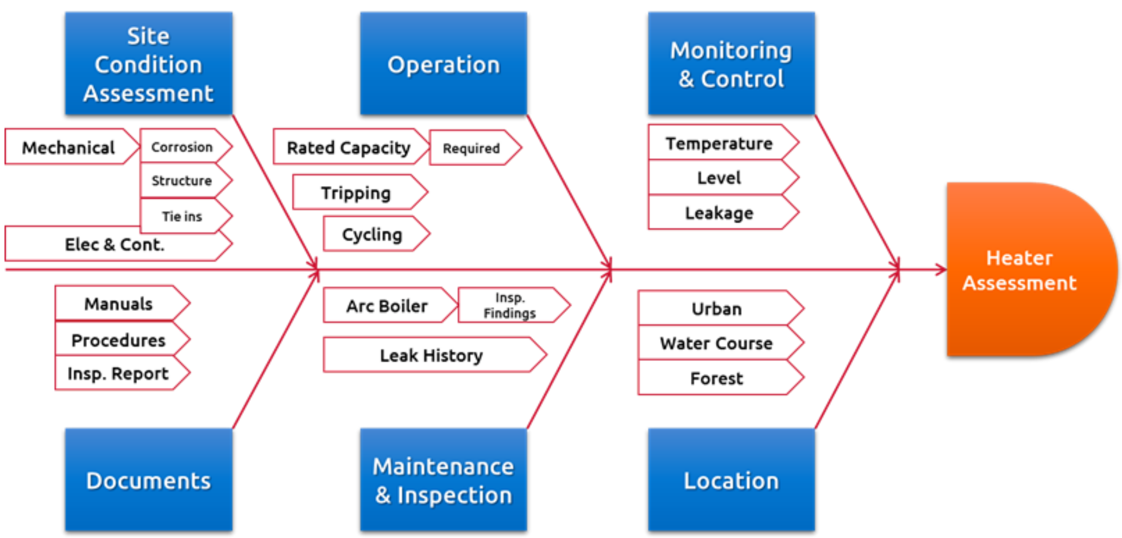
3.1 Heating Equipment Project (AMP ID 1174)

The holistic assessment of in direct-fired heaters across the franchise has been driven by: several glycol leakages, obsolete equipment, proximity to urban areas and water, inadequate heating capacity, and low efficiency. The identified objectives behind the assessment effort is to achieve safe, efficient and reliable heating systems; less hazardous to environment with low glycol contents; and suitable for future growth.

Heater Assessment Methodology

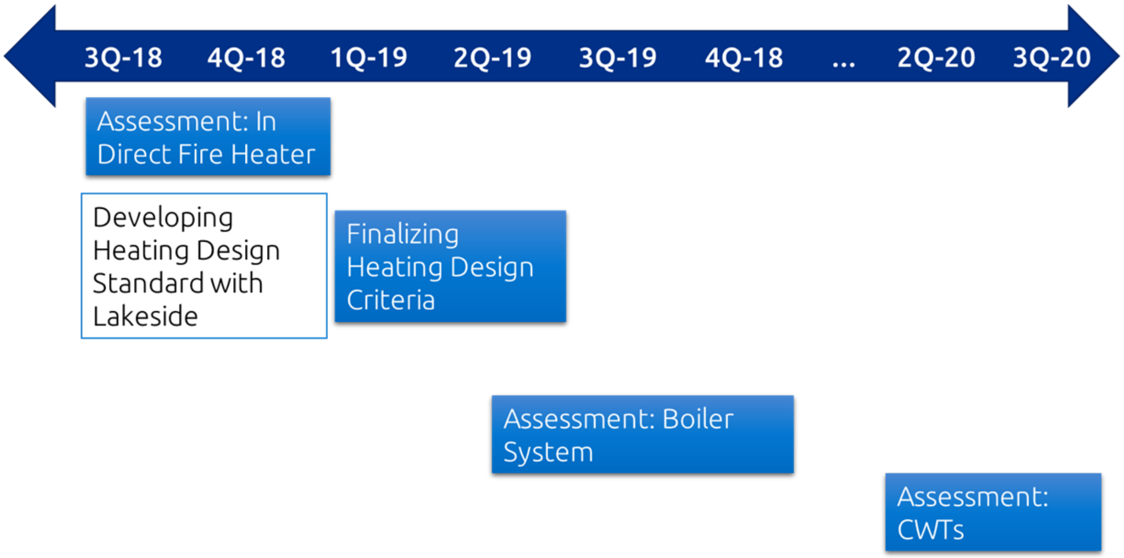


Risk Assessment Method



3.1.1 Scope

Natural gas flowing through buried pipelines loses thermal energy then when gas passes through pressure regulators. It is more subjected to the Joule Thompson effect which results in more thermal energy losses resulting in free-off around regulators and equipment malfunction. Therefore, heating equipment is used in different systems and customers' stations across the Union franchise to help mitigate this failure mechanism. Aging heating assets will need to be replaced or resized to match the required heat demand.



3.1.2 Expenditures

The forecasted expenditure of around $2 million per year is meant for the replacement or resizing of aging heating assets. This forecast will improve efficiency in operating costs of aging systems and will mitigate the risk of equipment failures that could result in loss of customers and/or loss of glycol containment.

3.1.3 Resources

This is an ongoing maintenance effort to replace equipment that has reached end of life or has been deemed obsolete. This work will maintain system reliability, ensure operating costs for heating systems are minimized and reduce the potential for glycol spills.

3.1.4 Leave to Construct

Not applicable.

3.2 Regulators/Reliefs Project (Portfolio: Regulators/ Reliefs)

3.2.1 Scope

Regulators and relief valves fail or require replacement due to age or obsolescence, whether it is at the time of meter exchange or in conjunction with other maintenance projects.

3.2.2 Expenditures

The capital expenditure on regulators and reliefs is estimated based on the historical consumption, purchasing and stocking to support ongoing maintenance work, which is equivalent to $9 to $10 million per year.

3.2.3 Resources

Regulators are purchased and stocked for field reps and technicians so that they can maintain the high reliability of our system and customer stations. This forecast will mitigate shortages of equipment so that services to customers are maintained.

3.2.4 Leave to Construct

Not applicable.

3.3 Stations Painting Program (AMP ID 1175, 206)

This is a centrally managed program to apply high performance paint to stations where existing paint has begun to fail or wear off of the facilities on which it has been applied. The station painting program is a significant corrosion mitigation practice. The frequency and criteria for high performance painting at station sites is specifically prescribed in our Corrosion Control Standard Operating Practice (SOP) and is our documented and committed practice with respect to how we comply with the applicable codes for corrosion control on above grade station assets. This work will improve compliance and ensure the safety and reliability of Union's assets by reducing the risk of leaks and piping and/or equipment failure due to significant corrosion.

3.3.1 Scope

A proactive survey has been completed for all in scope stations to capture current coating conditions (classified to NACE criteria). A number of site and environmental conditions which would impact the lifespan of the coating (proximity to road, ground and atmospheric conditions etc.) and other components which need to be factored into the coating plan (riser wrap condition, piping insulation, lead testing etc.) have been captured. Civil components which will also need to be addressed (supports, cabinets, buildings etc.) has been captured. This data has been used to systematically prioritize all stations.

The goal of the program is to ensure all target locations are completed within a 15 year timeframe and that a sustainment program is established to ensure subsequent proactive recoating orders are established based on the individual site and atmospheric conditions. There will be a yearly project execution window of May to October beginning in 2019.

3.3.2 Resources

All high-performance coating application work will be completed by qualified contractor resources. Station assessments and all required pipe maintenance (riser coatings etc.) will be completed by company resources. All documentation components (SAP) will be completed by company resources.

3.3.3 Expenditures

The total expenditure for this program is $19.5 million. $1.5 million will be allocated in 2019 and $2 million annually for the years following.

3.3.4 Leave to Construct

Not Applicable.

4 Compression & Dehydration

4.1 Obsolete RB211-24A Dawn C Plant Project (AMP ID 1055)

Dawn C Plant is one of the nine centrifugal compressors located at the Dawn Compressor Station. It is primarily used to lift from lower storage pressure levels, experienced later in the operations season, to intermediate pressure levels. The intermediate pressure level is typically elevated further in pressure by another compressor to reach the desired Dawn outlet pressure. Dawn Plant C and Plant D have a suction pressure rating of 195 psig, which is the lowest rating of the compressor fleet at Dawn. Considering the other compressors at Dawn have a 225 psig minimum inlet rating, Dawn Plants C and D become very critical when pool storage levels fall below 225 psig as they typically do late in the operational season.

Overall, compression can pose a very large consequence of failure as compressors are integral assets required to achieve the Dawn to Parkway Transmission System deliverability requirements throughout the year. The consequence of compressor failure is dominated by gas cost impacts to customers. Transmission System consequences associated with failure of a single compressor are heavily influenced by the time of year, weather severity and time to mitigate the failure.

Siemens, the original equipment manufacturer (OEM) of the Dawn C compressor, has indicated that 40 years is the typical timeframe over which they support supply of engine parts required to recover from a critical engine failure or to complete recommended overhauls. Dawn Plant C was installed in 1984, which is an indicator that the RB211-24A engine in Plant C is reaching end of life. By continuing to comply with OEM recommended Preventative Maintenance (PM) schedules and overhauls, compressor reliability risk is controlled to moderate levels but, risk increases gradually over the 25,000-hour recommended interval between overhauls. Availability of parts is essential to repair internal engine failures and complete overhauls. Notably, the RB211-24A in Plant C has non-standard dimensions and cannot be retrofitted with more modern editions of the RB211 without significant plant retrofits.

Similar to the 40-year old Dawn Plant B, which was replaced and retired in 2017 due to the risks associated with discontinued OEM support of critical engine parts, it is expected that Dawn Plant C will be exposed to a similar level of risk at the age of 40 which will justify replacement.

4.1.1 Scope

Aside from engine obsolescence, other core plant components within Dawn Plant C are reaching end of reasonable life: for example the compressor employs an oil seal system which is now an environmentally unfriendly technology, the noise generated from the building envelope is greatest in the Dawn fleet, and the electronic control systems are a generation behind in terms of monitoring and controls. As the entire plant is out of specification in terms of the new standard compressor station designs, it is recommended that Plant C be replaced in its entirety.

4.1.2 Expenditures

The cost of a new RB211 DLE plant is estimated at $155.9 million. Design is proposed to begin in 2022 with an in-service date of 2024 and abandonment of the obsolete Plant C structures in 2025.

4.1.3 Resources

Major Projects will work with a third party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

4.1.4 Leave to Construct

Leave to Construct is required. Timing will need to coincide with the 2022 start of the project.

4.2 Transmission Compression - Engine Overhaul Program (AMP ID 979, 1196, 1197, 949, 956, 226, 952)

Four critical compressor stations are strategically located along the Dawn to Parkway Transmission System: Dawn, Lobo, Bright and Parkway. Discrete blocks of centrifugal compression are located at each of the stations and used in various combinations to manage the seasonal and weather-dependent system flow demand. There are nine centrifugal compressors at Dawn, five at Lobo, four at Bright and four at Parkway ranging in horsepower outputs, vintages and models.

Transmission compressors can pose a very large consequence of failure as they are integral assets required to achieve the Dawn to Parkway Transmission system deliverability requirements throughout the year. The consequence of compressor failure is dominated by gas cost impacts to customers. Transmission system risk associated with failure of a single compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure.

The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM prescribed overhauls, the risk of unit failure is proposed as a saw tooth function, whereby risk increases gradually over the 25,000 hour recommended interval between overhauls and then drops suddenly after an overhaul. Based on average annual use, overhauls for each engine are between 12 to 18 years and are staggered, nominally one per year.

Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20 per cent or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases.

4.2.1 Scope

The 50,000 hour interval overhauls are more in-depth costing more than the 25,000 hour interval overhauls. The engines are typically removed and shipped to the OEM-approved shop in the April/May timeframe and are returned and reinstalled in the July/August timeframe.

NOTE: *The work timeframe is driven by available outage availability in accordance with the requirements of Gas Control and Business Development.*

Based on current trending, it is expected that the Bright A2 engine will reach 25,000 operational hours in 2022. An overhaul is required at 25,000 hours in accordance with Siemens specifications.

Year	Station	Plant	Engine	Operational Hours	Budget
2020	Dawn	J	Taurus T70S	40,000	$1,500,000
2023	Bright	A2	RB211 G DLE	25,000	$2,809,080
2023	Bright	B	RB211 24C	50,000	$2,288,880
2023	Bright	A1	RB211 G DLE	25,000	$3,265,871
2024	Dawn	J	Taurus T70S	40,000	$1,500,000
2025	Lobo	A1	Avon 1534 – 101G	50,000	$2,080,000
2026	Parkway	C	RB211 GT DLE	25,000	$3,100,000
2026	Parkway	D	RB211 GT DLE	25,000	$3,100,000
2027	Dawn	F2	Taurus 70S	40,000	$1,040,400
2028	Dawn	D	RB211 24C	50,000	$2,252,325

4.2.2 Expenditures

Engine overhauls range in cost from $1.0 million to $4.0 million depending on the engine model, condition and the overhaul interval.

The expected expenditure for this program is $25.5 million over the next ten years (2019-2028). This total expenditure includes costs associated with a number of smaller centrifugal compressor units listed in Section 5 Table 5.4.6.1.1

4.2.3 Resources

On-site work involving engine removal, reinstallation and commissioning, is carried out by the respective station mechanics and technicians. Time to complete the on-site work varies depending on compressor model and vintage. The removal and preparation for the shipping phase typically takes a week and the reinstallation and commissioning typically takes a week. On-site direction by an OEM field service representative may be requested in some of the more complicated installations.

Engine overhaul work is completed off site at the OEM approved shop.

4.2.4 Leave to Construct

Not applicable.

4.3 Waubuno Compressor Replacement Project (AMP ID 1152)

The Waubuno Compressor elevates available pipeline pressure to the Waubuno Pool MOP. Compression increases the working inventory value of the pool by approximately $2.2 million (at $0.75 per GJ) based on top of what the pipeline alone can achieve. The compressor is operated approximately 45 days per year in late summer to early fall to top off the pool.

The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the Waubuno Compressor is heavily influenced by the level of the pool at which the failure occurs and time to mitigate the failure.

The Joy Compressor (manufactured in 1985) was a used compressor package purchased by Union and installed at Waubuno in 1988. The Joy Compressor Company changed ownership approximately 20 years ago whereupon original equipment manufacturer (OEM) support for the compressor was discontinued. Although normal wear components are still available in the marketplace, replacement major compressor items such as cylinders, crankshafts, and rods, etc., required to support a critical failure are no longer available. In the event of a critical failure, sourcing used parts (which are rare) or aftermarket custom machining services would be the only options for repair. This was the case in 2007 when a discharge valve seat failed; resulting is catastrophic damage to the cylinder 611. An extensive search across the used parts dealers was required to secure a viable used cylinder head. Other internal damage was repaired through custom machining services. In the event of a future failure if useable parts or custom machining are not available, the two options would be custom-designed aftermarket castings (if possible) or replacement of the entire compressor. However, both options would render the compression out of service for at least one operational season.

4.3.1 Scope

This project involves replacement of the Waubuno Compressor to mitigate the risk of a critical part failure that would render the compressor out of service for an extended period of time. The proposed timing to complete the on-site work is during the first and second quarters of 2021. Design and ordering of long-lead items will need to occur a year in advance.

4.3.2 Expenditures

Total capital expenditure for the replacement of the Waubuno Compressor is estimated at $18.3 million.

4.3.3 Resources

Major Projects will work with a third party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

4.3.4 Leave to Construct

A Leave to Construct is required. Timing will need to coincide with the 2020 start of the project.

5 Liquefied Natural Gas

5.1 Boil Off Gas (BOG) Compressor Replacement Project (AMP ID 951)

The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. The Boil Off Gas (BOG) Compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160 degrees Celsius at which point the natural gas turns into a liquid. The BOG Compressor was also used to recover BOG (i.e., natural gas vapors) from the LNG storage tank which occurs on a continuous basis due to the ambient warming of the tank exterior. In 2012, a separate compressor was installed to manage the LNG storage tank boil off gas.

In addition to from the security of supply provided by the LNG plant, the plant has also been placed in service on occasion over the years to manage system demand. It supplemented the Marten River and Sudbury lateral capacities to manage required peak day deliverability. It was used as a virtual storage on the Dawn to Parkway Transmission System, minimizing take-off capacity at the Marten River and Sudbury Lateral TransCanada PipeLines (TCPL) take-offs to allow increased flows to arrive at the Parkway Custody Transfer Point.

The BOG Compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the BOG compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure.

Over its 50 years of operation, the 240 horsepower Ingersoll Rand BOG Compressor has amassed 325,000 operational hours. The compressor is obsolete and, although normal wear components are still available in the marketplace, core compressor replacement parts such as cylinders, crankshafts, pistons, etc., required to support a critical failure are no longer manufactured by the original equipment manufacturer (OEM). In the event of a critical failure, securing used parts (which are rare) or aftermarket custom machining services are the only options for a timely repair. This was the case in 2017 when an aftermarket service was solicited to develop a weld and machine repair of a compressor cylinder which had failed. The aftermarket service was able to design a custom repair which took three months to complete. In the event that the cylinder is not repairable, a custom-designed aftermarket casting or a complete replacement of the compressor may be options. These options would take the plant out of service for at least one operational season, rendering the plant unable to perform its regulated requirements.

5.1.1 Scope

This project involves replacement of the BOG Compressor to mitigate the risk of a critical part failure that is non-repairable.

5.1.2 Expenditures

Replacement cost of the BOG is estimated at $2.1 million. The proposed timing to complete the on-site work is during the second and third quarters of 2022. Design and ordering of long-lead items will need to occur a year in advance.

5.1.3 Resources

Major Projects will work with a third party engineering firm to complete the design and a contractor to complete the fieldwork. Operations will support Major Projects as required.

5.1.4 Leave to Construct

Not applicable.

5.2 Hagar Cold Box Replacement Project (AMP ID 1052)

The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. The Cold Box is several heat exchangers in series used to cool the natural gas feedstock to -160 degrees Celsius at which point the natural gas turns into a liquid.

In addition to from the security of supply provided by the LNG plant, the plant has also been placed in service on occasion over the years to manage system demand. It supplemented the Marten River and Sudbury lateral capacities to manage required peak day deliverability. It was used as a virtual storage on the Dawn to Parkway Transmission System, minimizing take-off capacity at the Marten River and Sudbury lateral TransCanada PipeLines (TCPL) take-offs to allow increased flows to arrive at the Parkway Custody Transfer point.

The Cold Box is the core of the LNG station and is necessary to produce LNG. The consequence of a Cold Box failure is dominated by customer impact. Risk of associated failure is heavily influenced by thermal cycling and operational hours.

Over its 50 years of operation, the Cold Box has amassed 140,000 operational hours. Significant failure modes include leakage of natural gas or refrigerants out of the piping into the interior of the Cold Box shell reaching potentially explosive levels or heat exchanger cross leaks that reduce the effectiveness of the refrigeration process. Both of these failure modes impair LNG production to the extent the plant cannot meet its annual production requirements. As the Cold Box internals are encased in very densely packed insulation and clad in an outer steel jacket, troubleshooting and repair of either of these failure modes is extremely difficult and time consuming. In 2017, an exercise was undertaken to isolate and leak test the various natural gas and refrigerant paths within the Cold Box in order to determine baseline leakage. Although some cross circuit leakage was found, the rate of leakage was deemed to be well within reason by the Subject Matter Expert Consultant. Future leak test data will be gathered and compared against the baseline data to predict leakage rate of change and consequential Cold Box end of life.

5.2.1 Scope

This project involves replacement of the Cold Box in advance of leakage that would impair the plant's ability to produce LNG. Considering the complex nature of internal repair or replacement of the Cold Box, reactively responding to internal leakage would render the liquefaction process out of production and unable to meet its regulated requirements for at least an operational season.

5.2.2 Expenditures

Replacement cost of the Cold Box is estimated at $6.2 million. The proposed timing to complete the on-site work is during the second and third quarters of 2025. Design and ordering of long-lead items will need to occur a year in advance.

5.2.3 Resources

Major Projects will work with a third party engineering firm to complete the design and a contractor to complete the fieldwork. Operations will support Major Projects as required.

5.2.4 Leave to Construct

Not applicable.

5.3 Hagar KVGR and Cycle Mix Cooler Replacement Project (AMP ID 1035)

The Hagar Liquefied Natural Gas (LNG) Plant was installed in 1968 to provide security of supply to the Sudbury industrial and distribution markets. The KVGR Compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160 degrees Celsius at which point the natural gas turns into a liquid.

In addition to from the security of supply provided by the LNG plant, the plant has also been placed in service on occasion over the years to manage system demand. It supplemented the Marten River and Sudbury lateral capacities to manage required peak day deliverability. It was used as a virtual storage on the Dawn to Parkway Transmission System, minimizing take-off capacity at the Marten River and Sudbury lateral TransCanada PipeLines (TCPL) take-offs to allow increased flows to arrive at the Parkway Custody Transfer point.

The KVGR Compressor is necessary to produce LNG. The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the KVGR Compressor is heavily influenced by the time of year, weather severity and time to mitigate the failure.

Over its 50 years of operation the 1,500 horsepower Ingersoll Rand KVGR Compressor has amassed 140,000 operational hours. The compressor is obsolete and, although normal wear components are still available in the marketplace, core compressor replacement items such as cylinders, crankshafts, pistons, etc., required to support a critical failure are no longer manufactured by the original equipment manufacturer (OEM). In the event of a critical failure, aftermarket, custom machining services are the only option for repair. In the event custom machining services are not able to make a repair, a custom designed aftermarket casting option or complete replacement of the compressor would he required rendering the LNG plant out of service for at least one operational season and rendering the plant unable to perform its regulated requirements.

5.3.1 Scope

This project involves replacement of the KVGR Compressor to mitigate the risk of a critical part failure that is non-repairable.

5.3.2 Expenditures

Replacement cost of the KVGR is estimated at $6.2 million. The proposed timing to complete the on-site work is during the second and third quarters of 2022. Design and ordering of long-lead items will need to occur a year in advance.

5.3.3 Resources

Major Projects will work with a third party engineering firm to complete the design and a contractor to complete the field work. Operations will support Major Projects as required.

5.3.4 Leave to Construct

Not applicable.

6 Measurement

6.1 Obsolete RTU Equipment / SCADA RTU Life Cycle Project (AMP ID 934, 935, 42)

The natural gas monitoring and control system is comprised of field equipment for the Supervisory Control and Data Acquisition System (SCADA) for monitoring and control of natural gas flow and odourizing natural gas at large stations, custody measurement, and control of critical valves. This system is crucial to provide live, natural gas, measurement and operational information through the SCADA to various stakeholders.

The natural gas monitoring and control system is made up of Remote Terminal Units (RTUs) - Bristol 3330/3310, which were installed from 1989 to 2006 with the majority installed between 1995 and 1999 in locations across Union’s entire franchise. Communication devices are also included (satellite/cellular/radio modems), which were upgraded between 2008 and 2010 and upgraded again from 2015 to 2019 in locations across Union’s entire franchise.

6.1.1 Scope

Many RTUs are 3330/3310 which were obsolete since 2009 and are no longer supported by the manufacturer. The forecast in this category includes projects to replace all the existing RTUs and replace with current technology ControlWave Micro introduced in 2003. This is a standardized approach that ensures enhanced control and current communication protocols for SCADA Gas Control, odourization, measurement data collection and volume nominations. Starting in 2024, the SCADA RTU life-cycle project will take over as the current technology will be 21 years old.

The benefit of these projects will be a smooth migration of in-service RTU fleet to current technology using a standardized approach. Currently, these legacy RTUs are at the end of their useful life and deferring this work may increase failure rate exponentially due to the wear-out effect.

6.1.2 Expenditures

The total project cost is $22.4 million for 2019 to 2028 with an average of $2.2 million per year.

6.1.3 Resources

All material and equipment are procured externally. Both internal and external resources will be used to complete different tasks under this project.

6.1.4 Leave to Construct

Not applicable.

6.2 Odourant Upgrades Project (AMP ID 30, 933)

Natural gas in its basic state is generally odourless and can be difficult to detect if accidently released to the atmosphere. Natural gas is therefore odourized at major stations as required per code Canadian Standards Association Z662 - Oil and Gas Pipeline Systems to make the presence of natural gas easier to detect, to protect the public and to operate our assets safely.

Measurement Asset Subclass	Device Type and Inventory
Odourization Systems (Bypass and Injection)	• Micro Odourant Injection System (MOIS) injection cabinets • Odourant injection tanks (approximately 71 sites) • Odourant bypass tanks (approximately 148 sites) • Environmental deodourizer units(at each injection site) • Level instrumentation(one at each odourant site)

6.2.1 Scope

This project includes upgrades to odourant systems to ensure compliance to current codes such as replacing old tanks and painting rusted containment pans and tank stands. Additionally, there is further performance capability added by installing heat traces lines, heated cabinets, improved tank valves and indoor regulator panels. This work will help to ensure safe, compliant and continuous odourization. This forecast will help mitigate the risk of tank rupture, frequent freeze-off and nuisance odour calls.

6.2.2 Expenditures

The total project cost is $10.6M million for 2019 to 2028 with an average of $1.1 million per year.

6.2.3 Resources

All material and equipment are procured externally. Both internal and external resources are used to complete different tasks under this project.

6.2.4 Leave to Construct

Not applicable.

6.3 Meter Exchange Program (AMP ID 927, 930, Portfolio: Labour Cost for Exchange)

This category is a program to remove meters and replace them with new meters. This work is as required to comply with the legal requirements of Measurement Canada. Batches of diaphragm type meters are removed each year and tested to ensure the population of meters in the field meet regulatory requirements. Smaller meters are compliance tested to meet regulatory requirements. Larger meters (rotary and turbine type meters) and electronic volume correctors (EVCs) are condition tested in service to confirm adequate performance levels. If performance levels are inadequate, the tested meters and EVCs are then removed, re-verified and returned to service.

6.3.1 Scope

The number of meter exchanges required beginning in 2019 is shown below. These exchange requirements are expected to continually grow as the overall in service population continues to grow.

- 200 series diaphragm meters – 54,402 exchanges.
- 400 series diaphragm meters – 4,851 exchanges.

6.3.2 Expenditures

The Meter Exchange Program budget forecast includes the procurement of all types of replacement meters, EVCs, Automated Meter Reading (AMR) devices, regulators for 200/400 series replacement meters and labour cost of 200/400 series replacement meters.

The total program cost is $324 million for 2019 to 2028 with an average of $32.4 million per year. Generally, there are two components of this cost as described below:

- Material and equipment cost is $172.8 million with an average of $17.28 million per year.
- The labour cost for 200/400 series replacement meters is $151.2 million with an average of $15.1 million per year.

6.3.3 Resources

All material and equipment are procured externally. The labour cost for 200/400 series replacement meters is based on 47 per cent replacements by company crew and 53 per cent replacements using external service providers.

6.3.4 Leave to Construct

Not applicable.

7 Underground Storage

7.1 Emergency Shutdown Valve Installation Project (AMP ID 1155)

Union has upgraded wellheads and installed emergency shutdown valves (ESVs) on 128 injection withdrawal (I/W) wells for Delta Pressuring projects since 2013. These upgrades reduce the risk associated with the well by having an automated shut-off at the wellhead. The ESVs can be controlled locally, remotely, through pressure loss or through thermal activation. There are pools in Union's storage system that have not been Delta Pressured due to economic or operational reasons. These are the Payne, Waubuno, Terminus, Sombra, Edys Mills, Heritage and Tipperary pools.

7.1.1 Scope

This project will upgrade the wellhead and install an ESV on the remaining 45 I/W wells over a 5-year period. The project reduces the risk on Union's storage wells by upgrading the wellhead to the current requirements of CSA Z341-18 and by installing ESV on each of these wells. This multi-year project will target 8 to 10 wellhead upgrades annually. The first year of the project is 2020 with upgrades to be performed in the Terminus pool.

7.1.2 Expenditures

The total cost of the project is $4.4 million.

7.1.3 Resources

The project will require outside contractors to install the new wellheads, ESVs and crossover modification. Design and project management will be performed by Union personnel.

7.1.4 Leave to Construct

Not applicable.

8 Service Facilities

8.1 50 Keil Drive Category 1 Facility Project (AMP ID 1161)

8.1.1 Condition Findings

The 50 Keil Drive office is a 178,000-square-foot facility located at 50 Keil Drive North in Chatham, Ontario. The facility serves as the corporate office for Union, and supports several critical corporate functions such as Gas Control, Engineering, Corporate Security, Human Resources and Finance. The original 70,000-square-foot building was constructed in 1964 in a commercial area with close proximity to major transportation routes. A 108,000 5-storey addition was put on in 1977. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.

In 2015, a facility condition assessment was conducted by WalterFedy (WF) which followed the general protocols for the Building Condition Assessment standard published by the Institute for Research in Construction division of the National Research Council of Canada (NRCC). Union provided the WF team with access to building drawings on file, historical inspection reports, equipment inventories and testing program results. Representatives from WF met with Union facility staff and trade contractors to conduct a series of on-site investigations and interviews regarding standard facility operations, maintenance procedures, equipment replacements etc. The WF team completed a building code analysis of the facility based upon the 2012 OBC, a site topographic survey of the property, and underground sanitary and storm sewer inspections by video camera. Finally, the condition of exterior surface works including pavement, sidewalks and landscaping was inspected and field notes, sketches, checklists, photographs etc. were completed as part of the on-site investigations.

The review found the building to be deficient in several building code and life safety requirements such as the absence of a sprinkler system, fire-rated assemblies, fire-rated structure, fire stopping, fire-rated and emergency exiting requirements.

Although adequately maintained, the building envelope was found to be only in fair condition, with signs of deterioration. Many building components such as the single pane windows are original, and there is evidence of moisture damage in many areas where the inadequate glazing and insulation has caused condensation on the interior wall and sill surfaces.

Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. An FCI score is not available for this facility. However, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. An Adequacy Index (AI) score is not available for this facility. Based on the investigation findings, the building does not meet the functional requirements of the business. However, the conditions are considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The site provides adequate parking and green space, and is located within adequate proximity to major transportation routes.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 45 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies are considered correctable on the existing property without the need to acquire additional land, the facility requires extensive refurbishment and improvements.

8.1.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at 50 Keil are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality, resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.1.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

The preferred strategy is option 1, to refurbish the existing facility on site. The current asset management plan has allocated funds in 2020, 2021, 2022, 2023 and 2024 for a staged implementation of the strategy. This approach will increase operational efficiencies and eliminate legacy risks associated with life safety deficiencies.

8.2 Belleville Category 3 Facility Project (AMP ID 1493, 1985)

8.2.1 Condition Findings

The Belleville Operations Centre is a 13,750-square-foot facility located at 127 Enterprise Drive in Belleville, Ontario in a location that adequately services the Belleville market. The age of the building is not known as it is a leased facility. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.

In 2016, an operational performance assessment was conducted by Union personnel which identified several deficiencies in the existing facility including but not limited to the inappropriate amount of space, inadequate storage, meeting space and site security, and legacy environmental concerns regarding water quality. The review also found the building to be deficient in several building code and life safety requirements.

Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. An FCI score is not available for this facility. However, the physical condition of the facility does not meet Union standards and is not considered correctable at this location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. An AI score is not available for this facility. Based on the review, the building does not meet the functional requirements of the business and the conditions are not considered correctable at the current location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Site: The site size is unknown. However, the site does not provide adequate traffic control, storage or security. These conditions are not considered correctable at the current location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 53 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The building and site deficiencies are numerous, and considered not correctable at this location due to the fact that this is a leased property.

8.2.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Belleville are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life-safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.2.3 Strategy

The following options to address these deficiencies have been assessed:

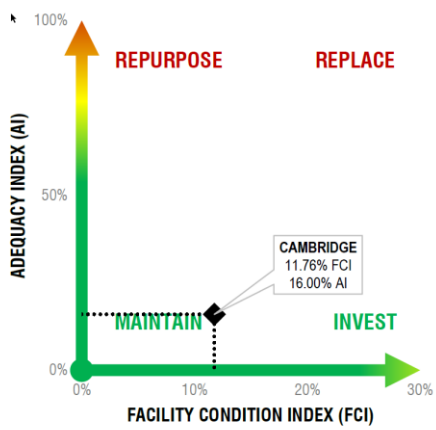
1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Terminate the lease agreement for this property and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

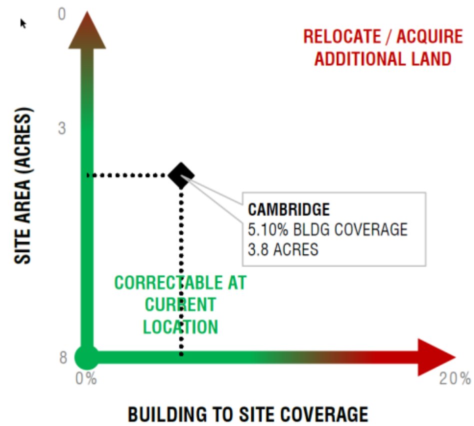
The preferred strategy is option two, to purchase land in a location with proximity to major transportation routes and construct a new fit-for-purpose facility. The current asset management plan has allocated funds in 2020 and 2021 to implement the strategy. This approach will increase operational efficiencies and eliminate legacy environmental risks associated with water quality.

8.3 Cambridge Category 3 Facility Project (AMP ID 1986)

8.3.1 Condition Findings

The Cambridge Operations Centre is an 8,800-square-foot Category 3 facility located at 221 Avenue Road in Cambridge, Ontario. The facility is considered an operations depot for the natural gas distribution business, and supports some administration support functions for the natural gas storage and transmission business. The original building was constructed in 1962 in a location with adequate access to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Cambridge facility is 11.76 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Cambridge facility Adequacy Index (AI) is 16 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The

Cambridge site does not meet operational requirements. The yard is 0.9 acres with a single access. However, the site has adequate space to accommodate a bigger yard.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 20 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards and the current building requires refurbishment and an addition. However, the building and site deficiencies can be corrected on the existing property without the need to acquire additional land or relocate to another property.

8.3.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Cambridge are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards
- Inadequate functionality resulting in productivity challenges for staff and visitors
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation
- Financial risk due to operating costs related to inefficient equipment
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards

8.3.3 Strategy

The following options to address these deficiencies have been assessed:

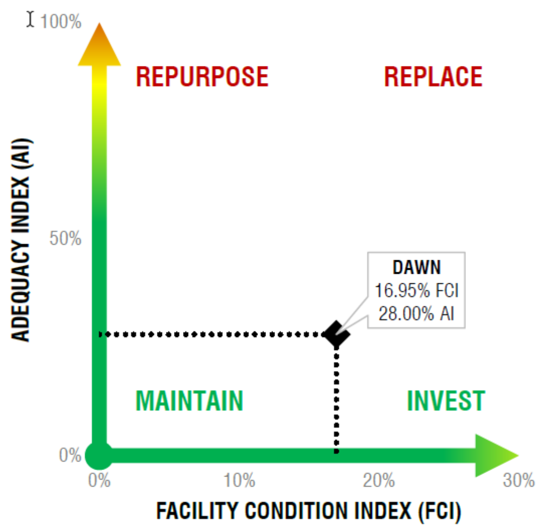
1. Correct physical and functional deficiencies by expanding and refurbishing the facility and yard on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

The preferred strategy is option one to correct deficiencies by expanding and refurbishing the existing facility and service yard. The current asset management plan has allocated funds in 2020 to fulfill the strategy. This is a more cost-effective approach and mitigates safety and financial risks.

8.4 Dawn North Admin Category 1 Facility Project (AMP ID 1167)

8.4.1 Condition Findings

The Dawn North Administration Centre is a 17,420-square-foot Category 1 facility located at 3332 Bentpath Line in Dawn-Euphemia Township, Ontario. This facility is the main administration centre for the natural gas storage and transmission business. A Master Control Room (MCR) for the natural gas storage and transportation system operates from this location and Dawn is the designated backup location for the Gas Control Centre at 50 Keil, as detailed in the corporate business continuity plan. The building was constructed in the 1970's on the Union Dawn Hub campus.



Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Dawn facility is 16.95 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Dawn facility Adequacy Index (AI) is 28 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility is considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The Dawn North Administrative office is one of many buildings on the Dawn campus. It does not meet Union safety standards due to its proximity to the operations yard.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, some of the furnishings are considered legacy and therefore not compliant with current standards.

Although FCI and AI scores suggest the Dawn North deficiencies are correctable at the current location, relocation to another property is recommended due to proximity to the storage and transmission operations yard. The Dawn Campus includes several other parcels of land which would be suitable for a new facility to be constructed on.

8.4.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at the Dawn North facility are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Potential of injury, illness or fatality as the building is located in close proximity to the natural gas operations yard.
- Inadequate functionality resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and building location.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.4.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by expanding and refurbishing the facility on the existing site.
2. Dispose of the existing facility and construct a new fit-for-purpose facility elsewhere on the Dawn campus.

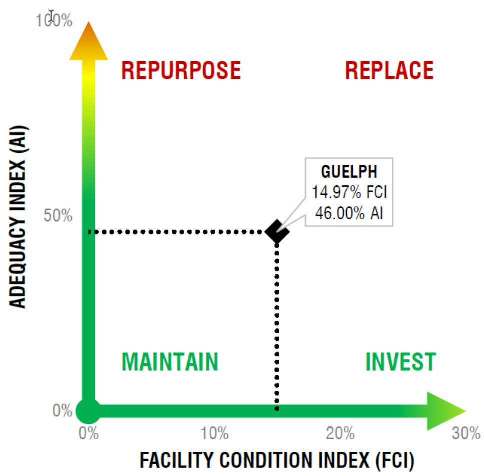
3. Do nothing.

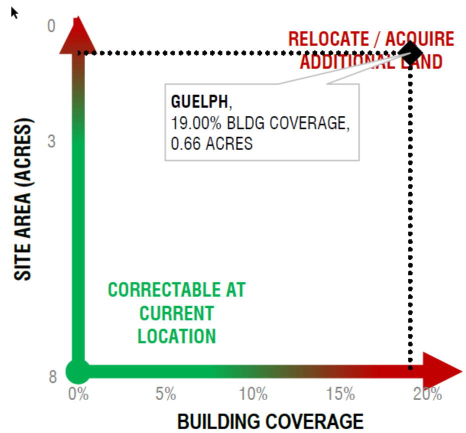
The preferred strategy is option two, to construct a new facility elsewhere on the Dawn campus. The current asset management plan has allocated funds in 2021 and 2022 to fulfill the strategy. This presents the safest, most cost-effective solution for maintaining a Category 1 facility.

8.5 Guelph Category 3 Facility Project (AMP ID 1987)

8.5.1 Condition Findings

The Guelph Category 3 Facility is a 6,659-square-foot building located at 10 Surrey Street in Guelph, Ontario. The facility is considered an operations depot and does not include any operational support functions. The original building was constructed in 1957 in a central location within proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements. There are legacy environmental concerns at this location as a result of prior owner's activities.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Guelph facility is 14.97 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Guelph facility Adequacy Index is 46 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location. However, this is not recommended.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The Guelph site does not meet operational requirements. The yard is 0.38 acres with a single access and considerable vehicle circulation constraints.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 100 per cent (all) of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards, and the current building requires refurbishment. Building expansion and yard configuration at this location are not feasible, and consideration to do so would require an environmental control strategy.

8.5.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Guelph are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.5.3 Strategy

The following options to address these deficiencies have been assessed:

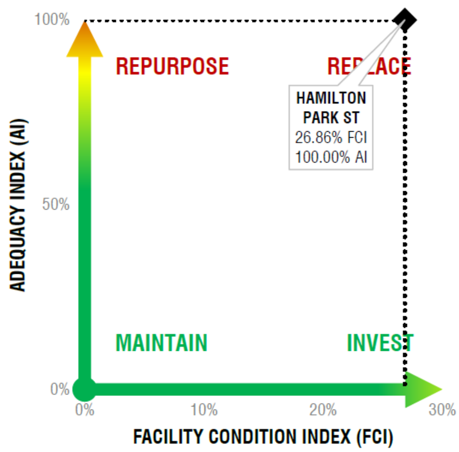
1. Correct physical and functional deficiencies by expanding and refurbishing the facility and yard on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

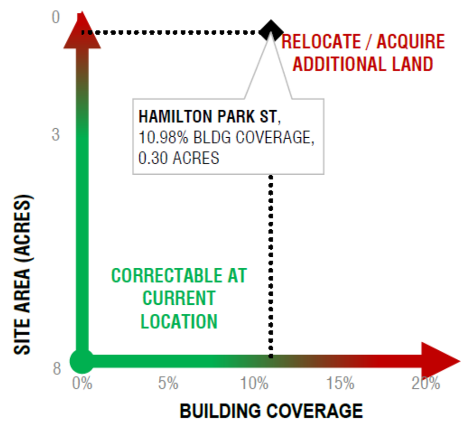
The preferred strategy is option two, to dispose of this facility and construct a new fit-for-purpose facility within proximity to major transportation routes. The current asset management plan has allocated funds in 2023 and 2024 to fulfill the strategy. This is a more cost-effective approach and mitigates safety, environmental and financial risks to the Company.

8.6 Hamilton Park Street Category 3 Facility Project (AMP ID)

8.6.1 Condition Findings

The Hamilton Park Street Operations Centre is a 1,438-square-foot Category 3 facility located at 133 Park Street North in Hamilton, Ontario. The original building was constructed in 1960 as a convenience depot for servicing the downtown area of Hamilton. The building purpose remains unchanged and no renovations have been completed since inception.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Cambridge facility is 26.86 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Hamilton Park Street facility Adequacy Index is 100 per cent and does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The Hamilton Park Street yard is 0.19 acres and does not meet the requirement for access, security and vehicle circulation.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, all 100 per cent (all) of the furnishings are considered legacy and therefore not compliant with current standards.

The existing building requires significant improvements. However, the property is too small to consider an investment at this time.

8.6.2 Risk and Opportunity

There are a number of consequences that Union can experience under continued operations at the Hamilton Park Street Operations Centre:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current Ontario Building Code (OBC) life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.6.3 Strategy

The following options to address these deficiencies have been assessed:

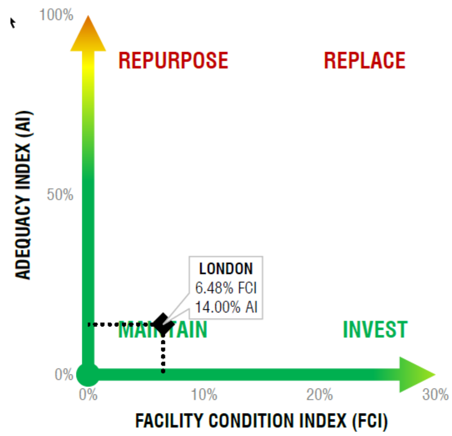
1. Purchase adjacent land and execute an expansion of the current facility. Correct physical and functional deficiencies within the building and the yard.
2. Sell existing property/facility and purchase property in the downtown core suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.
4. Close the existing facility and leverage operations depots at nearby Stoney Creek and Pritchard Road Hamilton.

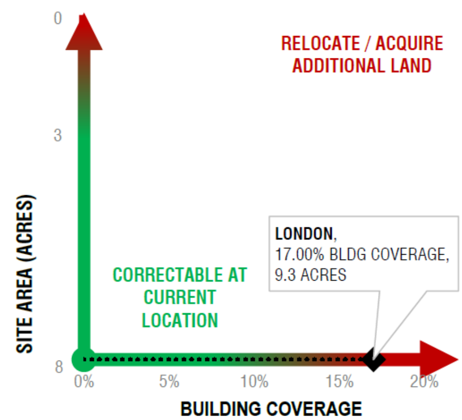
The preferred strategy is option four to close the existing facility and leverage neighbouring facilities. The current asset management plan has allocated funds in 2020 to fulfill the strategy. This is the most cost-effective approach and mitigates safety and financial risks to the Company.

8.7 London Category 1 Facility Project (AMP ID 1170)

8.7.1 Condition Findings

The London Operations Centre is a 66,840-square-foot facility located at 109 Commissioners Road West in London, Ontario. The facility serves as the main district office and provides operational support functions such as an emergency dispatch call centre, central warehousing and a fabrication (welding) shop. The London facility also serves as a main alternate location for critical corporate functions as outlined in the Corporate Business Continuity Plan. The original building was constructed in 1968 in a location that lacks direct access routes to the broader service area or major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Index Code (FCI) score of 0 per cent to 5 per cent. The FCI score of the London facility is 6.48 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The London facility Adequacy Index is 14 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The London site does meet operational requirements as the yard is 3.3 acres. However, the facility location is not ideal as it is not in proximity to major transportation routes.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 17 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies can be corrected on the existing property without the need to acquire additional land, the facility location does present operational logistics challenges.

8.7.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at London are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.7.3 Strategy

The following options to address these deficiencies have been assessed:

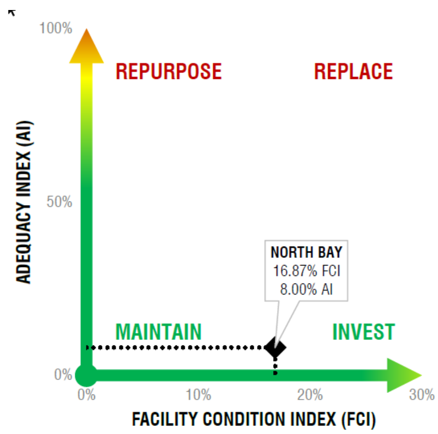
1. Correct physical and functional deficiencies by reconfiguring the yard and refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

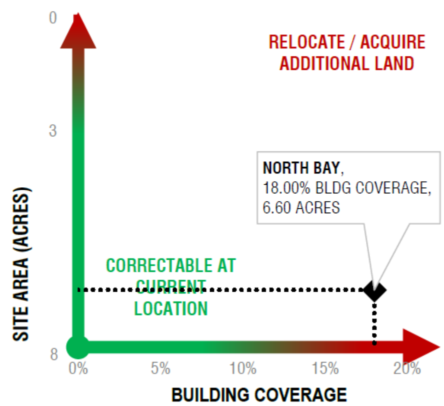
The preferred strategy is option one, to refurbish the existing facility at the current location. The current asset management plan has allocated funds in 2025, 2026, 2027 and 2028 to fulfill a staged refurbishment strategy. This approach presents the most cost-effective solution that will mitigate safety and operational risks to the Company.

8.8 North Bay Category 1 Facility Project (AMP ID 1988)

8.8.1 Condition Findings

The North Bay Operations Centre is a 39,280-square-foot facility located at 36 Charles Street in North Bay, Ontario. The facility serves as the district office and includes support functions including a commercial meter shop, a customer attachment call centre and central warehousing. The original building was constructed in 1964 in an area that has since been repurposed for residential housing. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the North Bay facility is 16.87 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The North Bay facility Adequacy Index (AI) is 8 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The North Bay site does meet operational requirements. The yard is 3.5 acres with multiple access drives.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 34 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards and the current building requires a renovation. The building and site deficiencies are correctable on the existing property without the need to acquire additional land. However, the facility is located in a residential neighbourhood without easy access to major transportation routes.

8.8.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at North Bay are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.8.3 Strategy

The following options to address these deficiencies have been assessed:

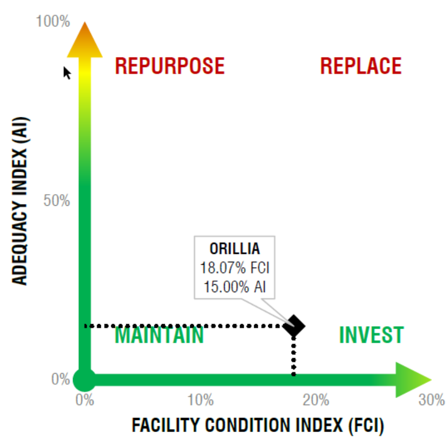
1. Correct physical and functional deficiencies by reconfiguring the yard and refurbishing the facility on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

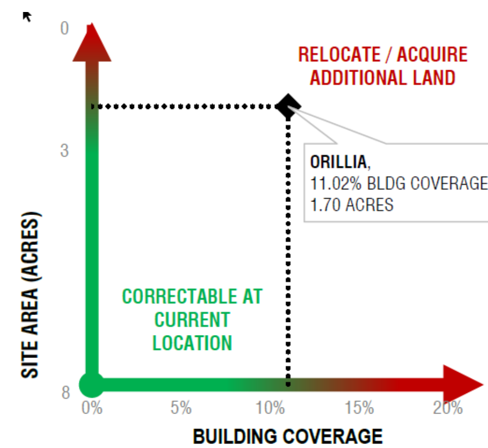
The preferred strategy is option two, to dispose of this facility and construct a fit-for-use facility in a commercial location with access to transportation routes. The current asset management plan has allocated funds in 2024 and 2025 to fulfill the strategy. This approach addresses operational logistics challenges, addresses the concerns of the residential neighbourhood and mitigates safety and financial risks to the Company.

8.9 Orillia Category 3 Facility Project (AMP ID 1171)

8.9.1 Condition Findings

The Orillia Operations Centre is a 12,254-square-foot facility located at 425 Memorial Avenue in Orillia, Ontario. The original building was constructed in 1974 in a commercial location that continues to service the surrounding area well. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Orillia facility is 18.07 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Orillia facility Adequacy Index (AI) is 15 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The site does meet operational requirements. The yard is 0.7 acres.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 58 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

The configuration and circulation of the yard does not meet Union standards and the current building requires a renovation. However, the building and site deficiencies are considered correctable on the existing property.

8.9.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Orillia are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors.
- Yard constraints hindering vehicular circulation and increasing the probability of motor vehicle accidents.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies and vehicle circulation.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.9.3 Strategy

The following options to address these deficiencies have been assessed:

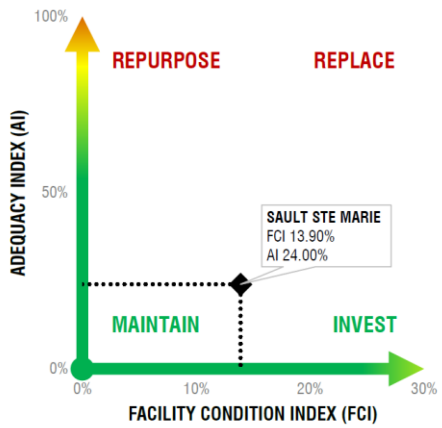
1. Correct physical and functional deficiencies by reconfiguring the yard and refurbishing the facility on the existing site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

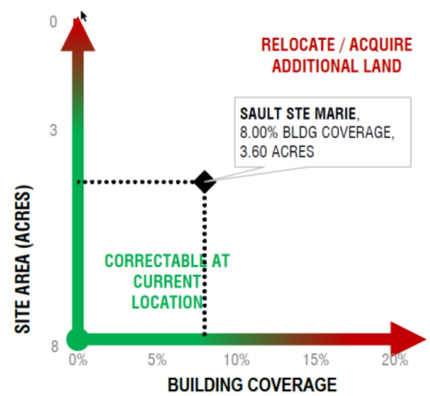
The preferred strategy is option one, to refurbish the existing facility and reconfigure the existing yard. The current asset management plan has allocated funds in 2022 and 2023 to fulfill the plan. This is the most cost-effective approach to mitigate safety and financial risks to the Company.

8.10 Sault Ste Marie Category 3 Facility Project (AMP ID 1990)

8.10.1 Condition Findings

The Sault Ste Marie (SSM) Operations Centre is a 9,500-square-foot facility located at 10 Industrial Court A in Sault Ste Marie, Ontario. The facility serves as an operations depot, and provides operational support with a fabrication (welding) shop. The original building was constructed in 1979 in an industrial area with close proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the SSM facility is 13.90 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The SSM facility Adequacy Index (AI) is 24 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The SSM site does meet operational requirements as the yard is 2.6 acres.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 100 per cent (all) of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies can be corrected on the existing property without the need to acquire additional land, the facility itself requires refurbishment and an addition.

8.10.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at SSM are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality, resulting in productivity challenges for staff and visitors.
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.10.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by adding an addition and refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

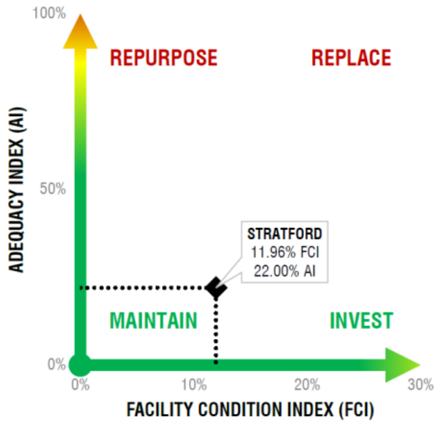
The preferred strategy is option one, to put an addition on the existing building and refurbish the existing spaces. The current asset management plan has allocated funds in

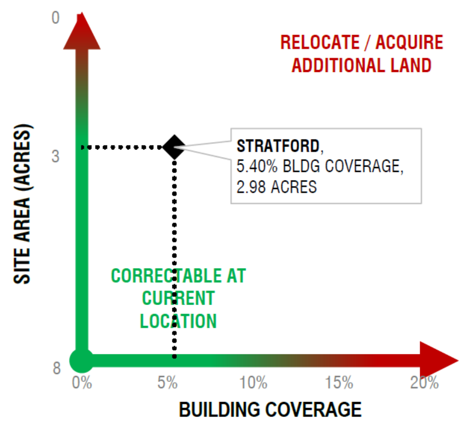
2025 and 2026 to fulfill the strategy. This approach presents the most cost-effective solution that will mitigate safety and operational risks to the Company.

8.11 Stratford Category 3 Facility Project (AMP ID 1173)

8.11.1 Condition Findings

The Stratford Operations Centre is a 7,000-square-foot facility located at 827 Erie Street in Stratford, Ontario. The facility serves as an operations depot. The original building was constructed in 1968 in a commercial area with close proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Stratford facility is 11.96 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Stratford facility Adequacy Index (AI) is 22 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
POSITIVE	Negative	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The Stratford site does not meet operational requirements as the yard is 1.07 acres with a single access.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 66 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies are considered correctable on the existing property without the need to acquire additional land, the facility itself requires refurbishment. There are also legacy environmental issues related to water quality at this site.

8.11.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Stratford are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality resulting in productivity challenges for staff and visitors
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.11.3 Strategy

The following options to address these deficiencies have been assessed:

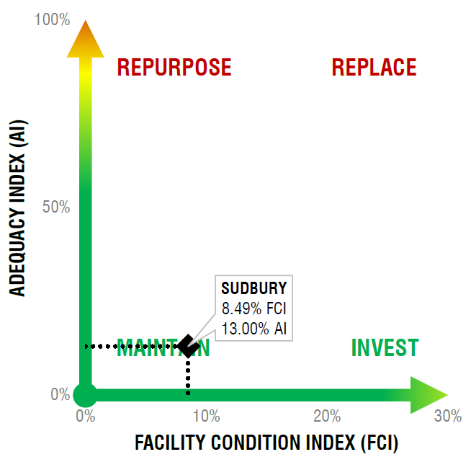
1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

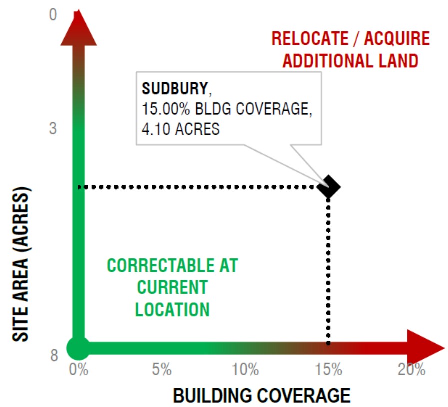
The preferred strategy is option two, to dispose of this facility and construct a new fit-for-purpose facility with access to major transportation routes. The current asset management plan has allocated funds in 2026 and 2027 to fulfill the strategy. This approach will increase operational efficiencies and eliminate legacy environmental risks associated with water quality.

8.12 Sudbury Category 3 Facility Project (AMP ID 1989)

8.12.1 Condition Findings

The Sudbury Operations Centre is a 41,686-square-foot facility located at 828 Falconbridge Road in Sudbury, Ontario. The facility serves as an operations depot and includes a distribution warehouse, a call centre and a fabrication (welding) facility. The original building was constructed in 1984 in a commercial area with close proximity to major transportation routes. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.





Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. The FCI score of the Sudbury facility is 8.49 per cent. Therefore, the physical condition of the facility does not meet Union standards.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. The Sudbury facility Adequacy Index (AI) is 13 per cent. Therefore, without consideration of other factors (such as adequacy of land and service coverage), the functionality of the facility would be considered correctable at the current location.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Functional Obsolescence - Site: The acceptable Union standard for functional condition is a 2.5-acre yard with dedicated traffic lanes for entry and departure. The Sudbury site does not meet operational requirements as the yard is 1.9 acres. However, this has not significantly impacted operations.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	POSITIVE	Negative

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 36 per cent of the furnishings are considered legacy and therefore not compliant with current standards.

Although the building and site deficiencies are considered correctable on the existing property without the need to acquire additional land, the facility itself is significantly oversized and requires extensive refurbishment. There are also legacy issues related to settlement of the building.

8.12.2 Risk and Opportunity

There are a number of consequences that Union can experience if the deficiencies at Sudbury are not corrected. These include but are not limited to:

- Higher operating costs and increased Greenhouse Gas (GHG) emissions due to inefficient equipment and building systems.
- Potential of injury, illness or fatality as the building does not conform to the current OBC life safety, barrier-free and universal design standards.
- Inadequate functionality, resulting in productivity challenges for staff and visitors.
- Logistics challenges resulting in productivity constraints.

These consequences pose a safety and financial risk to Union. The specific risks are as follows:

- Safety risk due to life safety deficiencies.
- Financial risk due to operating costs related to inefficient equipment.
- Customer satisfaction risk as the existing facility emits more GHG and uses more energy than a comparable new facility constructed at OBC and energy standards.

8.12.3 Strategy

The following options to address these deficiencies have been assessed:

1. Correct physical and functional deficiencies by refurbishing the existing facility on the current site.
2. Sell existing property/facility and purchase property suitably sized to accommodate a newly constructed facility and service yard.
3. Do nothing.

The preferred strategy is option two, to dispose of this facility and construct a new fit-for-purpose facility with access to major transportation routes. The current asset management plan has allocated funds in 2028 and 2029 to fulfill the strategy. This approach will increase operational efficiencies and eliminate legacy risks associated with structural settlement.

9 Technology and Information Services (TIS)

9.1 Banner Application Project (AMP ID 2274, 1997)

Banner Enlogix customer information system (CIS) is a Vertex software as a service (SAAS) offering for 1.4 million non-contract general use customers that was implemented across Union in 2000. Banner's main purpose is billing; the system annually transacts revenue over $1.5 billion. Banner is the system of record for customer, premise, account, service and meter information and all related processes.

In addition to the core CIS functions within the Banner application, there are several other associated applications Vertex provides such as Union's MyAccount application. This is a customer self-serve web portal for transacting and viewing bill images, consumption history, and registration/cancellation of EBP Equal Billing Plans (EBP) and Auto Payment Plans (APP). A copy of the code is maintained in escrow.

9.1.1 Scope

The enhancement investments for this project will ensure accurate billing services are provided to customers in Banner and meet regulatory and legislative requirements.

9.1.2 Expenditures

The total capital expenditure for the project is $122.6 million.

In 2019 and 2020, a $2.5 million enhancement to the online component (MyAccount) is required for compliance with the Accessibilities for Ontarians with Disabilities Act (AODA).

From 2019 to 2023, $9 million is required to remain compliant and implement enhancements to the system to ensure it continues to meet the business needs. Some of this work includes expected changes to the Customer Service Standards from the Ontario Energy Board (OEB) and changes to support the Energy Water Reporting and Benchmark (EWRB) regulation.

From 2024 through to 2027, the application will undergo a major life cycle replacement as the current version and underlying technologies will be over 20 years old.

9.1.3 Resources

The resourcing plans for this project are consistent with the historical expenditures. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.1.4 Leave to Construct

Not applicable.

9.2 CARE Application Project (AMP ID 2275)

The Classify Allocation Report and Exchange (CARE) application is Union's management system. It handles both incoming and outgoing nominations and validates the nominations against the related contracts for pipeline capacity. It is an in-house developed application that was originally developed in 1994 and sits on outdated architecture. As a result, this application has become difficult to support which coupled with the amount of break/fix change required to keep the system functioning is putting reliability and performance at risk. In addition, the programming language is nearing end of life making it difficult to find this skillset in developers.

CARE is one of three custom-built applications that serves Union's in-franchise and ex-franchise wholesale business (e.g., large contract rate distribution, direct purchase and storage and transportation customers) and is deemed the system of record for all gas inventories owned by Union and third parties. Every molecule of gas that enters or leaves Union's system, whether owned by Union or others, is accounted for in CARE on a volumetric basis. There are high expectations for reliability, availability and performance of the CARE application (7 days/24 hours/365 days) as it is the sole transaction system for our storage and transmission customers and internal business users.

The investment in enhancements and ultimately the life cycle of CARE is to ensure a stable, reliable, nomination and schedule system is in place that meets all regulatory requirements.

9.2.1 Scope

This project includes both annual enhancements and a life cycle project. Both are in place to ensure CARE remains stable and reliable.

9.2.2 Expenditures

The total capital expenditure for the project is $37.6 million. During 2020 to 2023, CARE will have a major life cycle replacement to ensure it continues to operate effectively.

9.2.3 Resources

For the annual enhancements, resource planning will occur when the requirements for the year are identified as per previous years.

For the life cycle project, professional resources for design and engineering will be contracted from the marketplace for this project. Union may be able to leverage the architecture and resources that are being used for ConTrax Modernization.

9.2.4 Leave to Construct

Not applicable.

9.3 CARS Application Project (AMP ID 2276)

The Construction Administration Records Systems (CARS) application is a Union application used to manage construction work orders used for new customer service lateral attachments. This application consists of an internally based application, an Internet facing application (GetConnected) as well as the business to business (B2B) component. It was developed in-house in 2009. The underlying technologies are aging and it is becoming increasingly difficult to enhance and support the application. CARS and GetConnected are custom-built applications written in C# using Visual Studio 2012, accessing an Oracle 12C database.

9.3.1 Scope

The project is intended to provide capital required to do a small amount of enhancements each year and keep the technologies used in support with the vendors. There is a major rewrite planned for both CARS and GetConnected in the next eight years.

9.3.2 Expenditures

The total capital expenditure for the project is $27.9 million. During 2021 to 2024, CARS will have a major lifecycle replacement to ensure it continues to operate effectively. In 2025, the online user interface referred to as GetConnected, will be life cycled to ensure it continues to operate securely.

Small enhancement projects are also budgeted for each year to drive efficiencies in the customer attachment workflow.

9.3.3 Resources

Union will look to implement an off-the-shelf solution rather than custom-built solutions as part of the lifecycle projects. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.3.4 Leave to Construct

Not applicable.

9.4 ConTrax Modernization Project (AMP ID 840, 2277)

ConTrax facilitates the contract to cash business processes for Distribution, Direct Purchase and Storage and Transportation (S&T) services for Union's large Commercial/Industrial customers. The application had become difficult to support due to the outdated technology and the complexity of the application as a result of having undergone several disparate and complex enhancements since it was initially implemented in 1995. The performance, reliability and flexibility of the ConTrax application is critical to Union's Business Development Storage and Transmission (BDST) growth strategy as well as the protection of base revenues. This project will modernize the ConTrax application and the ConTrax functionality in Unionline to protect Union's current business and support future growth. Wave 1 (south distribution market and core technology/architecture) of the project was successfully implemented in February 2017. Wave 2 (the rest of the distribution market) was successfully implemented in February 2018, with Wave 3 (Direct Purchase, S&T, all interfaces) scheduled to be implemented in February 2019.

9.4.1 Scope

This project will provide a modern technology stack to improve reliability, flexibility and time to market. While the underlying business processes have not changed, the manner in which they are facilitated through the application has been improved (e.g. workflow automation). The modernization of ConTrax will reduce planned and unplanned outages and will support business growth and protect existing revenue.

9.4.2 Expenditures

The total expenditure is estimated to be $17.5 million over the 10-year Asset Management Plan, not including $51.4 million spent prior to 2019.

9.4.3 Resources

This project will continue with the resourcing plan that has been in place for previous waves. In addition to Union Technology and Information Services (TIS) and business resources, there is a fixed price contract in place with the solution provider, Tata Consultancy Services for both onshore and offshore resources. Ernst and Young are providing onshore Project Management Office (PMO) services.

9.4.4 Leave to Construct

Not applicable.

9.5 Corrosion Application Replacement Program (AMP ID 2278, 2298)

The GL Essentials Corrosion Application (vendor provided software) provides asset-tracking, inspection and field data collection for routine inspection, maintenance and regulatory compliance activities on Union's pipelines. Technicians record reads, add sites, etc., on their laptops and refresh their local database when they return to the office. This is used companywide to support Union's cathodic protection system.

9.5.1 Scope

The current GL Essentials Corrosion Application will be replaced with a new solution. The software is overly complex to use and therefore inefficient. Alternative packages will be investigated as part of the lifecycle project in 2020 to 2021, including the potential of consolidating its functions into an existing application.

9.5.2 Expenditures

The total capital expenditure for the program is $4.9 million. The cost of a multi-year replacement project starting in 2020 is estimated at $3.8 million with additional costs allocated in subsequent years to allow for lifecycle/upgrades to the solution in order to maintain full vendor support. The program costs are based on Class 5 estimate.

9.5.3 Resources

The resourcing plans for this program are consistent with the historical expenditures. As the program plans are developed, the appropriate resources will be identified and implemented as required.

9.5.4 Leave to Construct

Not applicable.

9.6 Geographic Information Services (GIS) Application Program (AMP ID 2000, 2282)

Union's Geographic Information System (GIS) is used to store spatial and attribute information primarily related to underground assets (e.g., pipe, valves, fittings, district boundaries, structures, intersections, and cathodic protection, etc.). The GIS solution provides accurate data for planning, emergency response, Ontario Energy Board (OEB) mandated compliance items such as Ontario One Call, hydraulic modelling, municipal data sharing, and property tax, etc.

A module of the GIS system, G/Technology Designer, is used to design distribution services in order to release Issued for Construction (IFC) drawings to the field and also is used to update GIS based on as-built field drawings for transmission and distribution pipe projects.

G/Technology NetViewer provides a read-only interface to Union's GIS. G/Technology MobileViewer provides network disconnected read-only access to Utility Services Representatives (USRs) while working in the field. GeoMedia is the technology used for more traditional spatial analysis by select GIS technicians.

9.6.1 Scope

The annual GIS program is used to fund enhancements required to support changing business need (e.g., OEB mandated annual class location survey). The program is also used to fund larger software upgrades and life-cycle initiatives such as the GIS life cycle planned for 2022 to 2024. The current software version was originally implemented in 2007 and last updated to a more current version in 2017.

9.6.2 Expenditures

The total capital expenditure for the program is $22.2 million over 10 years. Typical annual GIS Program maintenance costs are in the range of $160 thousand to $240 thousand per year. During 2022 to 2024, the system is scheduled to go through a major life-cycle replacement. The cost of that particular upgrade is estimated between $11 million and $15 million assuming a potential change in the underlying GIS technology.

9.6.3 Resources

The resourcing plans for this program are consistent with the historical expenditures. As the program plans are developed, the appropriate resources will be identified and implemented as required.

9.6.4 Leave to Construct

Not applicable.

9.7 Meter and Measurement Application Project (AMP ID 2290, 2305)

Meter and Measurement is a set of applications that captures meter readings from residential, commercial and high volume customers, passing the data onto the appropriate billing systems.

Itron's Field Collection System (FCS) supports the residential meter reading business clients. This package interfaces with the Banner application to allow for billing of residential meters. The FCS application itself allows for route management, route status, route assignment/re-assignment and reporting.

The Gas Measurement Account System (GMAS) collects and validates all daily (or hourly) measurements at Union and sends to downstream systems such as ConTrax and Classify Allocation Report and Exchange (CARE) among others. The business clients interact with the system by accepting measurement warnings, closing meters at month-end and entering meter consumption manually when it is not available from Autosol when the meter is not communicating. The business clients also configure or group meters together for reporting purposes. There are also canned reports as part of the application.

Autosol is a polling engine application which makes calls to telemeter devices and reads measurement information which is then passed to GMAS for validation.

9.7.1 Scope

There are several upgrades to the vendor packages to ensure the applications remain supported and current over the span of 2019 to 2028 ranging from in-place upgrades to doing a market scan to ensure Union still using the technology that best meets our needs.

In addition, there are a couple of larger initiatives:

- In 2020, $2.5 million of funding is required as it is expected that there will be a significant increase in the number of Automated Meter Reading (AMR) devices (e.g., Electronic Receiver Transmitters [ERTs]) implemented across Union's franchise through an anticipated project and regular life-cycling of meters. As a result, there is a need to manage and provide a means of reporting on the increase in data (monthly to hourly) that we will receive as a result of this change.
- In 2021, $1.4 million has been set aside due to the need to life-cycle the ITRON handheld units used to capture the monthly reads. There are approximately 230 handhelds and docking stations that were purchased in 2012 and the current support agreement ends December 31, 2021.

9.7.2 Expenditures

The total capital expenditure for the project is $7.5 million. In 2020, a $2.5 million upgrade to incorporate reads from meters with AMR devices will be performed. In 2021, a $1.4 million life cycle of the Itron handhelds and docking stations is required to remain supported. The other spending is on enhancements to enable the application to continue to meet business needs and remain supported.

9.7.3 Resources

The resourcing plans for this project are consistent with the historical expenditures. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.7.4 Leave to Construct

Not applicable.

9.8 SCADA Application Replacement Project (AMP ID 2015, 2014, 2288)

The Supervisory Control and Data Acquisition (SCADA) system is used by the Union's Gas Control and Dawn Master Control Centres. It operates the company's pipeline and storage pool facilities. It is a critical 7 days/24 hours/365 days system. This set of projects continues to enhance components of the Union SCADA system in support of changing control room requirements and enhance the security of our telemetry infrastructure. Towards the end of the 10-year program, we are considering a complete replacement of the current system as there is a good chance it will be running an out-of-date operating system and end of life hardware and application software that will no longer be supported. The last major life-cycle replacement of the vendor software (i.e., Cygnet) was in 2011. The new hardware and software for this program is therefore necessary in order to use a modern architecture and includes enhancements for business, designed for both maximum security and reliability. This project will mitigate potential significant risks related to safety, finance and reputation by avoiding the continued use of outdated hardware and software.

9.8.1 Scope

The SCADA Replacement Project will start scheduling for the last few years of the 10-year Asset Management Plan. This project will involve the purchase of an entirely new SCADA system for the Union Master Control Room, including all new hardware and the new SCADA application software solution, as well as the implementation of the solution and its components. Other work included in the intervening years is allocated for telemetry upgrades, encryption rollout, and control room enhancements.

9.8.2 Expenditures

The total capital expenditure for the project is $15.4 million. The cost of the project enhancements in 2019 will be $1 million with the remainder of the funds being allocated each year through to 2023 after which the SCADA upgrade is scheduled for $10.3 million. The costs are estimated for hardware, software and professional services and are based on a Class 5 estimate.

There are no contingency or historical costs available for this project.

9.8.3 Resources

Professional resources for design and engineering will be contracted from the marketplace for this project. Historically, Union has retained architectural and engineering consulting services for the execution of similar projects.

9.8.4 Leave to Construct

Not applicable.

9.9 Service Suite Application Project (AMP ID 841, 2284)

The Service Suite application provides Work Management functionality to the majority of our Distribution Operations field workforce at Union. Planning and Dispatch Centres in London, Burlington, and North Bay manage the work for approximately 430 Utility Services Representatives (USRs) and dispatch this work through a cellular network to Panasonic Toughpads that are docked in each USR's vehicle. It is also a key technology for managing and dispatching Emergency Service orders 24 hours a day. The solution has significant interfaces with our CIS system (Banner) and Payroll system (SAP) via our time reporting and crewing application (WARP). The Service Suite application has been used at Union for the past 20 years with the last major upgrade occurring in 2007. The current version of Service Suite is 8.1.3. and is anticipated to be out of support with the vendor in 2020. This version is also dependent on aging technologies such as Windows 7 that present vendor support issues for the environment.

9.9.1 Scope

The focus of this project is to upgrade the aging Service Suite application to a newer version of the product and extend the life of the system. This is intended to be a technical upgrade with minimal new functionality added. Changes to the interfaces and reporting environment will also be minimized and only touched were needed as part of the upgrade or where objects could be retired.

9.9.2 Expenditures

The total expenditure are estimated to be $13.3 million over the 10-year Asset Management Plan. This does not include $3.2 million spent prior to 2019.

9.9.3 Resources

The resources on the project will be a mix of internal IT resources, functional area resources, and resources from the software vendor. As the project plans are developed, the appropriate resources will be identified and engaged as required.

9.9.4 Leave to Construct

Not applicable

9.10 Cloud Applications Program (AMP ID 2295)

Cloud applications are classified as cloud services that support specific, functional, business needs Applications. This Program includes funding for these applications: Contract Management System (CMS), Land Rights Management (GeoAmps) and Leak Survey (VeroTrack).

This program includes both application upgrades and a life cycle project to ensure these applications remain stable and reliable.

9.10.1 Scope

The investment in upgrades and ultimately the life cycle of these applications is to ensure stable and reliable systems are in place that meets all regulatory requirements.

9.10.2 Expenditures

The total capital expenditure for these projects is $2.3 million. In 2022, Land Rights Management (GeoAmps) will have a major life cycle replacement to ensure it continues to operate effectively.

9.10.3 Resources

For the upgrades, resource planning will occur when the requirements for the year are identified as per previous years.

For the life cycle project, professional resources for design and engineering will be contracted from the marketplace for these projects.

9.10.4 Leave to Construct

Not applicable.

9.11 Asset Management Application Program (AMP ID 2291)

This program will build an application to manage the Asset Management Program within Union and provide the tools and processes as identified in ISO 5500X. Enhanced asset analytics and decision support tools will be added to mitigate financial risks.

9.11.1 Scope

This program will contain elements of both packaged and developed applications. The implementation software will include the following:

- Capital portfolio management.
- Asset analytics and processing.
- Data capturing.
- Condition-based analysis.
- Performance management.

The program will oversee various business enhancements to existing asset management applications that will ensure the following:

- Meet the requirements for Union's asset management process.
- Implement the asset analytics and decision support tools.
- Implement software and applications to mitigate financial risks.

The program will start in 2019.

9.11.2 Expenditures

The total capital costs for the project are estimated to be $3.1 million over the 10-year period of the Asset Management Plan. In 2020, $1.2 million is required to purchase the software and $450 thousand to complete the foundation for the solution in 2021. The other spending is on enhancements to enable the application to continue to meet business needs.

The costs are based primarily on historical spend. In some cases, specific activities are identified within the Program, where high level estimates of resourcing including professional services, where identified are used. The program costs are based on a Class 5 estimate. This project is included under the Applications – Other portfolio in Section 5 Table 5.4.8.3.4.1.

9.11.3 Resources

High level requirements would be gathered from the business groups' subject matter experts (SMEs) to determine the level of effort required to complete the initiatives/projects under this Program. Existing Union resources with the required skills, knowledge, and capacity will be assigned to the appropriate initiatives/projects. If resources are not available, staff augmentation will be required and contractor staff will be on-boarded as per the needs of the initiatives/projects.

The resourcing strategy is identical to projects and programs executed in the past in the Union application development process.

9.11.4 Leave to Construct

Not applicable.

9.12 Material Traceability Application Project (AMP ID 2005, 2292)

The purpose of the Material Traceability Application Project is to provide a technical solution to ensure compliance with the Canadian Standards Association (CSA) Z662-15 code requirements.

Changes in the Z662-11 code have led to a higher level of scrutiny required in terms of records for materials and the ability to demonstrate material qualifications/specification through those records. The Technical Standards and Safety Authority (TSSA) adopted Z662-11 in November 2012 and it has since been revised to Z662-15 which was adopted by the TSSA in July 2016 (no changes to the material traceability requirements occurred between the 2011 and 2015 editions).

The Z662-11/Z662-15 codes require complete records for the material, including what specification it was made to, and the designer must ensure that it meets current requirements, which could lead to an Engineering Assessment.

9.12.1 Scope

There is a need to ensure information on the materials Union deploys in the field is accessible to the organization throughout the life of the asset. The specific types of information required are identified in the code. A technical solution will need to be deployed for field use that will allow maintenance and new-installation crews to identify the material they are deploying on specific job sites. This material information must be searchable by the business to ensure there is visibility into what materials are deployed where.

A roadmap will need to be developed to articulate how the requirements for Material Traceability will impact our current systems and potentially require new solutions as well. The roadmap will also layout the timing and scope of those changes along with the timing of the different asset types. A project plan will be built from this roadmap.

9.12.2 Expenditures

The total capital expenditure for the project is $2.5 million. The plan is to initiate the project in 2019 and, in subsequent years, incur other expenditure to complete the project and also enhance the solution to meet business needs in accordance with the defined roadmap. This project is included under the Applications – Other portfolio in Section 5 Table 5.4.8.3.4.1.

9.12.3 Resources

The resourcing plans for this project are consistent with other Technology and Information Services (TIS) projects. As the project plans are developed, the appropriate resources will be identified and implemented as required.

9.12.4 Leave to Construct

Not applicable.

9.13 Unionline Project (AMP ID 2287, 2011)

Unionline is a web-based transaction and information application that provides contract customers (i.e., large commercial and industrial, storage and transportation and energy marketers) with the ability to conduct business with Union online (i.e., nominating and reporting).

This project includes an annual program and an upgrade to the underlying technology in order to ensure reliability, performance, and to ensure Union remains compliant and competitive.

9.13.1 Scope

Annually, Union has an ongoing program for making regular investments into Unionline to enhance its function and reliability, allowing it to remain competitive with other pipeline online transactional systems. Its focus is to improve performance and reliability of the Unionline application and its internal supporting applications of CARE and ConTrax. In addition, this program is used when there are industry related changes that need to be made to the applications or new regulated changes that are not significant in nature.

In 2025, some funding has been set aside in order to review the Unionline from a lifecycle perspective. A portion of Unionline was upgraded in 2014; but with the fast changing web environment, there will likely be a need to enhance the application to support the consumer demands or changes in technology.

9.13.2 Expenditures

The average yearly program cost over the 10-year period is $25 thousand annually with an upgrade planned for 2025 to 2026 of $2.1 million.

9.13.3 Resources

A yearly program commences at the start of the year. The necessary resources are identified and perform the rollouts as per the project plan for each program year.

9.13.4 Leave to Construct

Not applicable.

9.14 Desktop Life Cycle/Sustainment Project (AMP ID 2017, 2297)

This project provides for the replacement of end user laptops and desktops using the preferred four-year refresh cycle, which mitigates financial risks. This project is in place to avoid significant operating costs due to the breakdown of aging devices along with the costs required to repair and to avoid productivity losses due to older equipment failing and being unable to keep up with operating system and software advances.

9.14.1 Scope

This project replaces the end user computing devices (laptops and desktops) as per the preferred four-year refresh cycle. It uses a cyclical approach for replacement based on warranty expiry, the logistics around operating system upgrades and hardware technology advances.

The project will start in 2019 and continue over the 10-year period until 2028.

9.14.2 Expenditures

The total capital expenditure for the project is estimated to be $28.6 million over the 10-year Asset Management Plan. The estimate is based on the expected cost of replacement devices multiplied by the number of devices to be replaced in a given year. The project costs are based on a Class 5 estimate. The expenditure amounts are consistent with the historical costs of the Project with no cost contingency.

9.14.3 Resources

As the project commences at the start of each year, the necessary resources are identified and purchased to perform the rollouts as per the project plan for that year. This resourcing plan is identical to that used in previous years for such a project.

9.14.4 Leave to Construct

Not applicable.

9.15 Server Life Cycle/Sustainment Program (AMP ID 2019, 2297)

Servers consist of devices that operate Unions' applications and data. This program provides for the replacement of servers using the preferred six-year refresh cycle and a cyclical approach for replacement based on warranty expiry and hardware technology advances. This helps the business application systems to perform as needed, and keeps technology current and at a supportable level. The program will also reduce potential outages due to aging hardware and avoid costly hardware maintenance charges as the equipment nears warranty.

9.15.1 Scope

This program will procure the replacement servers per vendor specifications and configure and implement the replacement servers into landscapes as per the preferred six-year refresh cycle.

The program is executed twice over the 10-year period starting in 2019 and again in 2025 with some procurements annually.

9.15.2 Expenditures

The total capital expenditure for the program is estimated to be $8.3 million over the 10-year Asset Management Plan.

The estimate is based on the expected cost of replacement in a given year. The program costs are based on a Class 5 estimate. The expenditure amounts are consistent with the historical costs of the program with no cost contingency.

9.15.3 Resources

This program will use vendor resources to install and configure the servers, consistent with resourcing used historically for this type of program.

9.15.4 Leave to Construct

Not applicable.

9.16 Utility Service Representative's Toughbooks Program

This program provides for the replacement of the rugged workstation hardware in the field used by the Utility Services Representatives (USRs) using the preferred four-year refresh cycle. This approach mitigates financial risk by avoiding significant increased operating costs due to failure of aging devices along with avoiding productivity losses (due to older equipment failing) and being unable to keep up with operating system and software advances. The maintained stability of the equipment ensures the USR has the required information to address the assigned work as well as emergency situations that are dispatched to the field. The current unit that is used in the trucks is the Panasonic Toughbook CF-31.

9.16.1 Scope

This program replaces the rugged workstation hardware in the field as per the prescribed four-year refresh cycle. It uses a cyclical approach for replacement based on warranty expiry, the logistics around operating system upgrades and hardware technology advances. The lifespan is deemed optimal to manage the total cost of ownership (TCO) of the units.

The program will start in 2020 and continue over the 10-year period until 2028.

9.16.2 Expenditures

The total program cost is estimated to be $9 million over the 10-year Asset Management Plan. The estimate is based on the expected cost of replacement devices multiplied by the number of units to be replaced every four years. The replacement program is anticipated to be implemented in 2020, 2024 and 2028.

9.16.3 Resources

As the project commences at the start of each year, the necessary resources are identified and purchased to perform the rollouts as per the project plan for that year. This resourcing plan is identical to that used in previous years for such a project.

9.16.4 Leave to Construct

Not applicable.

9.17 IT Technologies Program (Portfolio: IT Technologies)

The Information Technology (IT) Technologies Program contains a small portfolio of technology platforms that are used within IT and can be generally categorized as application integration systems, business intelligence systems, database systems, and application delivery support systems. Application integration systems allow the interconnection of processes and exchange of data among different business applications. Business intelligence systems allow business data to be queried, reported, and analyzed from our application systems to aid in corporate strategy planning and decision-making. Database systems provide the backend relational database technologies for storage of business data, as well as related client software to allow applications to connect to these databases. Application delivery support systems provide for software code management, web-based application operations, and software tools.

There are a number of consequences to Union if these key technologies are not maintained or renewed. These include:

- Extended outages due to failure of unsupported vendor foundational software
- Cybersecurity breaches due to the inability to apply security patches to unsupported software

9.17.1 Scope

The age range of all of the IT technologies extends to 20 years. However, plans are in place to decommission older IT technologies as more current technologies are available. The replacement/refresh strategy is driven by forecasted changes to the existing software products themselves and requirements from the business and associated applications.

The program is executed twice over the 10-year period.

9.17.2 Expenditures

The total program cost is estimated to be $12.1 million over the 10-year Asset Management Plan. The estimate is based on the expected cost of replacement of these technologies. The project costs are based on a Class 5 estimate. The expenditure amounts are consistent with the historical costs of the project with no cost contingency.

9.17.3 Resources

This program will use both internal and vendor resources to install and configure these IT technologies, consistent with resourcing used historically for this type of program.

9.17.4 Leave to Construct

Not applicable.

3.3 APPENDIX C: LIST OF EGD RATE ZONE BUSINESS CASES

<text>

Asset Class: Business Development **Business Case ID:**19223
Estimate Class: Class 5

Project Information

Name: Establishing Hydrogen (H2) Interoperability Criteria

Type: Enbridge Program **Start Year:** 2018

Asset Program: NGV

Project Type: Engineering

Issue/Concern:
To determine the ability to blend hydrogen as renewable content within the distribution system. Market Need – Numerous regulatory, legislative and commercial market drivers are signaling a near-term requirement for the utility's infrastructure to accommodate increasing renewable energy content within the pipeline network. This renewable content will include but will not be limited to hydrogen. Documentation of the market need includes:

- Enbridge Gas Distribution (EGD) Dec 2016 submission into Ontario's Long Term Energy Plan (LTEP) which identifies the cost-effectiveness of renewable gas supplies as an alternative to renewable electricity.
- Ongoing identification of multiple renewable natural gas (RNG) technologies that will include hydrogen as part of the renewable gas composition.
- The Ontario Ministry of Environment & Climate Change (MoECC) documented hydrogen as a proposed compliant fuel option in their October 12, 2016, technical advisory entitled "Renewable Content Requirement for Natural Gas".
- The Government of Canada's stakeholder engagement on the development of Clean Fuel Standards (CFS).

This will include renewable content requirements for natural gas systems. Canada expects to publish the proposed regulations in the Canada Gazette in mid-2018 with final regulation in 2019. See EGD's April 25, 2017 submission into Canada's CFS consultations.

Furthermore, Business Development is fielding inquiries from across its customer base seeking commercial arrangements to inject renewable gas supplies into the EGD pipeline network. This includes both RNG supplies, which could include some hydrogen in the gas composition, and also direct hydrogen injection from the evolving Power to Gas (PtG) energy storage solutions.

Assets:
. H2 distribution pipeline
. Pipeline systems (ie., Regulator, controls etc.)
. Blending system
. Manual(s) and technical document(s)

Related (Asset)Program (if applicable):
. Power to Gas plant

Compliance: N

Solution Description:

Scope of Work
Engineering
This business case supports the work scope identified in the June 8, 2017 engineering assessment. This includes the identification and documentation of pre-existing theoretical and practical knowledge involving the inclusion of hydrogen in natural gas systems. Deliverable from this engineering assessment includes; developing the appropriate standards, design specifications, policies and procedures to manage a closed loop portion(s)of the natural gas system to operate with hydrogen blends. This work establishes the foundation for EGD's management of the natural gas network where hydrogen will become a part of the gas composition within the pipeline system (i.e. close loop that is downstream of the H2 pipeline and blending system).
The above work is required to meet EGD's obligations that are included in Section 3.2 of the engineering assessment,
including:
• Internal EGD Requirements
• Compliance with Technical Standards and Safety Authority (TSSA)
• Ontario Energy Board (OEB) Requirements
• Other safety / regulatory obligations including Measurement Canada, end-use equipment codes and standards, etc.
Construction
Based on the above Engineering scope of work, EGD Major Projects will execute the planning, construction and commission of all aforementioned assets as per the schedule agreed to by the joint ventures, EGD, and other third party funding partners.

Out of Scope
Expanding the capacity of the Power to Gas plant and demonstration.

Resources: Third party contractor, EGD Major project & EGD Engineering

Project Timing and Execution Risks: Getting third-party funding from the Sustainable Development Technology Canada and the Ontario Centres of Excellence.
Based on EGD engineering development of the policies, procedure and standards, schedule could be impacted.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	822,557	$6,761,243	32

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$1,671,661	$1,213,833	$3,697,000	$0	$0	$0	$0	$0	$0	$0	$6,582,494
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,671,661	$1,213,833	$3,697,000	$0	$0	$0	$0	$0	$0	$0	$6,582,494
Retirement Cost											
Total Project Cost	$1,671,661	$1,213,833	$3,697,000	$0	$0	$0	$0	$0	$0	$0	$6,582,494

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Customer Assets **Business Case ID:**19983
Estimate Class: Class 3

Project Information

Name: Meter Purchases- MXGI's, MXG's, MXOT's

Type: Enbridge Project **Start Year:** 2018

Asset Program: Meters - Capital Purchase Program

Project Type: Meter Purchases

Issue/Concern:

Meters are used to determine the gas consumption input of customer billing. The replacement program for meters is mandated by Measurement Canada. The program includes: testing, repair, and replacement requirements of meters and instruments. All verified meters are approved by Measurement Canada with an issuance of a certificate which identifies that the meter complies with Electricity and Gas Specification S-EG-02. EGD must ensure all measurement devices remain in compliance for annual audits by Measurement Canada. Measurement Canada specifies tolerances under which the meter must operate in the field. EGD must demonstrate that all aspects of its meter sampling, maintenance, and replacement comply with these criteria in order to be accredited by Measurement Canada to be an “Authorized Service Provider” and adhere to Measurement Canada’s accreditation standard S-A-01.

Meters may also require exchange for issues such as: damages, leaks, customer billing issues.

Compliance: Y

Solution Description:

Scope of Work is for 2019 - 2027, and includes:
Purchase of meters for:
1) MXGI/MXGS - meters due for sampling and exchange. (61,895 units planned annually)
2019 Revised units: 36,404
2) MXOT - meter exchanges due to damage/leak/failure/customer dispute. (16,561 units estimated annually)

Solution Impact:
1) Compliance with governance mandated meter exchange program
2) Exchange of problematic meters

Resources: System Measurement and Purchasing manages the procurement of meters.

Project timing & Execution risks: This is an annual program that spans the entire year.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	22,355,007	$190,562,968	158

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$2,580,000	$26,827,932	$7,631,909	$15,953,412	$23,104,876	$19,359,766	$26,409,972	$19,724,555	$19,653,284	$21,117,262	$190,562,968
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,580,000	$26,827,932	$7,631,909	$15,953,412	$23,104,876	$19,359,766	$26,409,972	$19,724,555	$19,653,284	$21,117,262	$190,562,968
Retirement Cost											
Total Project Cost	$2,580,000	$26,827,932	$7,631,909	$15,953,412	$23,104,876	$19,359,766	$26,409,972	$19,724,555	$19,653,284	$21,117,262	$190,562,968

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1						R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R1						R0
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Customer Assets **Business Case ID:**23228
Estimate Class: Class 4

Project Information

Name: Meter Purchases- New Customer Additions

Type: Enbridge Project **Start Year:** 2020

Asset Program: Meters - Capital Purchase Program

Project Type: Meter Purchases

Issue/Concern:

New meters are required for customer expansion projects. Meters are used to determine the gas consumption input of customer billing.

Compliance:

Solution Description:

Scope of Work is for 2020 - 2027, and includes:
Purchase of meters for:
-New customer additions - customer expansion projects. Units estimated as follows:
2020 - 33,468
2021 - 33,964
2022 - 33,196
2023 - 32,486
2024 - 31,390
2025 - 30,592
2026 - 29,320
2027 - 28,588

Solution Impact: Support of customer expansion projects.

Resources: System Measurement and Purchasing manages the procurement of meters.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	0	$45,901,261	0

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$6,095,976	$5,565,792	$5,465,728	$5,385,944	$5,253,138	$5,166,584	$5,006,881	$6,826,666	$0	$0	$45,901,261
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,095,976	$5,565,792	$5,465,728	$5,385,944	$5,253,138	$5,166,584	$5,006,881	$6,826,666	$0	$0	$45,901,261
Retirement Cost											
Total Project Cost	$6,095,976	$5,565,792	$5,465,728	$5,385,944	$5,253,138	$5,166,584	$5,006,881	$6,826,666	$0	$0	$45,901,261

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Fleet & Equipment **Business Case ID:**3526
Estimate Class: Class 4

Project Information

Name: 2017- 2021 - 484 Light and Medium Duty Vehicles

Type: Enbridge Project **Start Year:** 2017

Asset Program: Capital Purchase Program - Vehicles

Project Type: Other

Issue/Concern:

Light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.

Asset: Light Duty vehicles and Medium Duty vehicles.

Related Program: N/A

Compliance: N

Solution Description:

Scope of work: This Project provides EGD with the necessary fleet vehicles to safely and efficiently run its business operations. The goal of the Project is to maintain the integrity of all fleet assets for safe and reliable operation. This ongoing replacement strategy optimizes the asset life cycle, improves safety, and reduces risk for the Company and its employees. To help achieve this goal, Fleet utilizes financial cost analysis, risk analysis, and physical asset assessment to guide replacement decisions.

Resources: Fleet & Equipment staff

Solution Impact: In order to replace aging fleet assets, a report is generated by the fleet management analytical software tool Flagship Replace which uses raw fleet data to identify all vehicles meeting the replacement criteria. The direct impact is reduced O&M repair and maintenance costs, and improved driver safety.

Solution Options

		Options		
Option Name	**Selected Option**	**Risk Mitigated**	**Total Net Direct Capital**	**LRROI**
Option 1	Y	2,474,495	$22,822,266	108
Option 2		2,474,495	$20,822,266	118

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$4,653,574	$1,146,120	$5,068,514	$6,902,904	$5,051,154	$0	$0	$0	$0	$0	$22,822,266
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,653,574	$1,146,120	$5,068,514	$6,902,904	$5,051,154	$0	$0	$0	$0	$0	$22,822,266
Retirement Cost											
Total Project Cost	$4,653,574	$1,146,120	$5,068,514	$6,902,904	$5,051,154	$0	$0	$0	$0	$0	$22,822,266

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0R1					
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Information Technology **Business Case ID:**8925
Estimate Class: Class 5

Project Information

Name: IT - 00 - Desktop Replacement (2018 - 2028)

Type: Enbridge Program **Start Year:** 2018

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

Replace end user computing devices (laptops, desktops, field devices) that are out of warranty and at end-of-life as per the asset life cycle strategy. Inability to replace units will result in significant productivity challenges for EGD personnel, as laptops will break down and suffer significantly degraded performance. In addition, laptops must be compatible with current operating software; for 2018 and 2019, this relates to Windows 10.

Assets: TIS - Hardware (laptops, some desktops, ruggedized field laptops)- each year's number of replacements will be different as warranties expire.

Related Program: N/A

Compliance: N

Solution Description:

This project includes procurement of the devices required in the particular calendar year, the configuration, scheduling and deployment of the devices to the impacted users, and the cost of desktop technicians required to perform the rollouts.

Approach: Standard TIS project management methodology will apply, including a signed charter and approved project plan for each calendar year, including procurement and rollout activities.

2019: Brought forward funding from 2020 to assist in the purchase and implementation of the next generation of Panasonic field devices, so as to be able to roll them out as part of the Windows 10 implementation. $1.5M of funding was brought forward from 2020 as part of the $2.6M funding increase required.

2020: Funding requirements reduced from $2M to $500K, due to the bring-forward of funds into 2019 for the Panasonic field device procurement (as above).

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	1,248,520	$7,470,000	122

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$2,425,000	$2,970,000	$500,000	$1,575,000	$0	$0	$0	$0	$0	$0	$7,470,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$2,425,000	$2,970,000	$500,000	$1,575,000	$0	$0	$0	$0	$0	$0	$7,470,000
Retirement Cost											
Total Project Cost	$2,425,000	$2,970,000	$500,000	$1,575,000	$0	$0	$0	$0	$0	$0	$7,470,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Information Technology **Business Case ID:**8602

Estimate Class: Class 5

Project Information

Name: Operation Digital

Type: Enbridge Project **Start Year:** 2019

Asset Program: IT Implementation

Project Type: Information Technology

Issue/Concern:

Ensure that engineering documents (policies, procedures, standards, and processes) are compliant to both regulatory and standards that follow process safety policies and have well defined procedures as it pertains to work on EGD assets. Reduce costs in creating, maintaining, and delivery of engineering documents while still remaining compliant. Improve the readability of engineering documents so that they can be more easily understood and followed in order to reduce safety incidents. Improve the overall delivery and consumption of engineering Document content to both internal and external EGD stakeholders. Establish a governance structure so that engineering documents are kept up to date and meet regulatory standards and compliance.

Asset: TIS - Software (Software packaged)

Related Program: N/A

Compliance: N

Solution Description:

The solution will include tools to perform the transformation of engineering documentation into a format where it can be re-used, with an ease of update and consistent look. In addition, with the new engineering content framework it will require a publishing mechanism to allow for consumption of the content in various operational situations. Content consumers also include Extended Alliance partners.

Approach: Standard TIS project management approach, including a signed charter and approved project plan for each calendar year, encompassing the design, build, test and implementation phases.

Resources: Project resources will include a PM, BA, data architect, developers/support analysts and QA personnel.

Related program: N/A

Timing and Execution Risks:
2020: Funding requirements lowered from $3M to $1.5M. Primary driver for the reduction was a change in solution approach, utilizing a third party vendor that significantly reduced the costs associated with the documentation digitization.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	3,735,488	$3,800,000	262

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$1,300,000	$1,500,000	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$3,800,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,300,000	$1,500,000	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$3,800,000
Retirement Cost											
Total Project Cost	$1,300,000	$1,500,000	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$3,800,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Pipe **Business Case ID:**17363
Estimate Class: Class 5

Project Information

Name: NPS 8 Clarington to Cathcart Integrity Retrofits

Type: Enbridge Project **Start Year:** 2019

Asset Program: Integrity Retrofit - Pipe

Project Type: Integrity Retrofit

Issue/Concern:

An Area 40 pipeline was communicated to have exceeded the Maximum Operating Pressure (MOP) threshold for integrity mains (operating above 29.5% SMYS) by the MOP team. The pipeline is identified as NPS 8 Clarington to Cathcart-Stewart Station – Network # 4781 that is operating at 400 PSI which corresponds to 30.4% SMYS.

The current operating set pressure for the pipeline as acquired from Source Records 2016/2017 is 400 PSI, corresponding to 30.4% of pipe material SMYS, which means that the pipeline needs to be included in the Integrity Management Program, according to TSSA CAD, FS-220-16, Clause 10.3.11.

If the pipelines are operating above 29.5% SMYS, they fall within the definition of an IMP pipeline that is in scope of EGD's Integrity Management Program (IMP). Typically, this means that In Line Inspection (ILI) is performed and follow up integrity digs are performed to mitigate risk by measuring/monitoring the condition of the high risk operating pipeline. The IMP is in response to TSSA CAD 2016, 10.3.11: "For the protection of the pipeline, the public and the environment, the operating company shall develop a pipeline integrity management program for steel pipelines operated at 30% or more of the SMYS of the pipe at MOP that complies with the applicable requirements of clause 3.2 of CSA Z662-15." and is a mandatory regulatory requirement.

Assets: NPS 8 Clarington to Cathcart-Stewart Station – Network # 4781 (operating at 400 PSI)

Related Programs: Network #4781

Compliance: N

Solution Description:

Scope of Work: Retrofits & Digs - Scope includes a series of thirteen retrofits. The retrofits include installation of a pig launcher and a pig receiver as well as eleven (11) other retrofits on pipe assets.

Resources: Execution to be completed by contractor resources.

Solution Impact: Some excavations along the pipeline route.

Project Timing and Execution Risks: Unknown conservation permit conditions and ground conditions.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	N	0	$6,433,297	0
Option 2		0	$13,200,000	0
Option 3	Y	0	$5,350,835	0

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$176,250	$5,174,585	$0	$0	$0	$0	$0	$0	$0	$0	$5,350,835
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$176,250	$5,174,585	$0	$0	$0	$0	$0	$0	$0	$0	$5,350,835
Retirement Cost											
Total Project Cost	$176,250	$5,174,585	$0	$0	$0	$0	$0	$0	$0	$0	$5,350,835

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**17364
Estimate Class: Class 5

Project Information

Name: NPS 8 Blackburn Extension

Type: Enbridge Project **Start Year:** 2019

Asset Program: Integrity Retrofit - Pipe

Project Type: Integrity Retrofit

Issue/Concern:

An Area 60 pipeline was communicated to have exceeded the Maximum Operating Pressure (MOP) threshold for integrity mains (operating above 29.5% SMYS) by the MOP team. The pipeline is identified as NPS 8 Blackburn Bypass that is operating at 470 PSI which corresponds to 30.8% SMYS. The current operating set pressure for the pipeline is 470 PSI, corresponding to 30.8% of pipe material SMYS, which means that the pipeline needs to be included in the Integrity Management Program, according to TSSA CAD, FS-220-16, Clause 10.3.11.

If the pipelines are operating above 29.5% SMYS, they fall within the definition of an IMP pipeline that is in scope of EGD's Integrity Management Program (IMP). Typically, this means that In Line Inspection (ILI) is performed and follow up integrity digs are performed to mitigate risk by measuring/monitoring the condition of the high risk operating pipeline. The IMP is in response to TSSA CAD 2016, 10.3.11: "For the protection of the pipeline, the public and the environment, the operating company shall develop a pipeline integrity management program for steel pipelines operated at 30% or more of the SMYS of the pipe at MOP that complies with the applicable requirements of clause 3.2 of CSA Z662-15." and is a mandatory regulatory requirement.

Assets: Network #6580

Related Programs/BCs: N/A

Compliance: Y

Solution Description:

In 2019, we will focus on design and engineering, procurement of long lead items and fabrication spools. This will result in a planning only scope in 2019 for this project. Proposed solution based on preliminary planning for this project is as follows:

1. Launcher installation (with and Oversize & Nominal) and an NPS 8 Isolation Block Valve installed at the corner of 3092 Innes Rd.
2. LSF component to be removed and replaced with straight pipe and barred tee at Innes

Rd. and Opp 1916 Du Clairvaux.

3. LSF component to be removed and replaced with straight pipe and barred tee at Innes Rd. and Opp 1920 Du Clairvaux.
4. Cut out LSF and install WSS Tee (bypass required due to busy intersection) at Innes Rd. and Orleans Blvd.
5. Cut out LSF and install 3D or greater Elbows, Tee's associated with LSF would have to be cut-out and replaced with pipe and elbows >3D. This is a very busy intersection at Innes Rd. and Orleans Blvd.
6. Replace elbow with long radius elbow at Opp 3519 Innes Rd.
7. Receiver Install - The pipeline section ends under Innes Rd, thus recommend the more practical approach of routing the receiver trap configuration (Receiver with oversize and nominal, NPS 8 Isolation Block Valve) to the south side of Innes Rd. at Opp 3519 Innes Rd.

Resources: Contractor / TFS

Solution Impact: Multiple excavations, some temporary shut-off may be required, some bypass' required and Innes Rd. and Orleans Blvd. is a busy intersection.

Project Timing and Execution Risks: This project was deferred from 2019 to 2020 due to permitting and design not being in place in time to support a 2019 installation.
Execution Risk: Underground conditions unknown.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	0	$3,935,000	0
Option 2	N	0	$3,500,000	0

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$480,000	$3,455,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,935,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$480,000	$3,455,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,935,000
Retirement Cost											
Total Project Cost	$480,000	$3,455,000	$0	$0	$0	$0	$0	$0	$0	$0	$3,935,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:** 6423
Estimate Class: Class 5

Project Information

Name: NPS 30 Don River Replacement

Type: Enbridge Project **Start Year:** 2017

Asset Program: Main Replacement

Project Type: Major Pipeline Project

Issue/Concern:
Main replacement project identified by Asset Management - Pipelines as high-priority. This is an LTC project and the OEB filing number is EB-2018-0108.
Studies have identified structural issues with the Bridge that can become further impaired during flood events which could cause the Bridge to fail resulting in catastrophic failure of the pipeline. The pipeline is a critical feed to the densely populated urban Toronto area. Damage to this crossing at peak design temperature would result the loss of ~ 92,500 customers, and may take days or weeks to restore service, once the pipeline issue has been addressed.

Assets: NPS 30 XHP Main.

Related Programs/BCs: NPS 20 HP, XHP and Station Replacement project (BC 10087) NPS 20 Lake Shore KOL (Cherry to Bathurst) (BC 10088)

Compliance: N

Solution Description

Scope:
This project is for the replacement of approximately 0.35 km of NPS 30 XHP on the Don River Crossing. The current estimate assumes micro-tunneling under the Don river.
Resources: Third party contractor - NPL and Ward & Burke
Solution Impact:
Replacement required due to the risk assessment results on the bridge over the Don River.
See Section 5.2.5 in the asset plan

Solution Timing and Execution Risk:
2019 Construction (Q1 start)
Risks: TRCA, Metrolinx, third-party development, City of Toronto

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	237,147	$24,214,772	26
Option 2		237,147	$24,389,512	26

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$333,801	$959,059	$19,596,987	$4,266,583	$0	$0	$0	$0	$0	$0	$25,156,430
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$333,801	$959,059	$19,596,987	$4,266,583	$0	$0	$0	$0	$0	$0	$25,156,430
Retirement Cost				$1,000,000							$1,000,000
Total Project Cost	$333,801	$959,059	$19,596,987	$5,266,583	$0	$0	$0	$0	$0	$0	$26,156,430

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							R0
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years						R0	
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							R0
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							R0
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Pipe **Business Case ID:**8933
Estimate Class: Class 5

Project Information

Name: Integrity Digs >30% SMYS BLANKET (10 year plan: 2018-2027)

Type: Enbridge Program **Start Year:** 2018

Asset Program: Integrity Digs - Pipe

Project Type: Integrity Digs

Issue/Concern:

The EGD Transmission Integrity Management Program (TIMP) monitors the condition of the pipelines that operate at or above 30% Specified Minimum Yield Strength (SMYS). The Program mitigates risk through the detection and remediation of features that are risks to the safe operation of the pipeline. Pipeline inspections are performed by the following two methods:
- In Line Inspections (ILI), internal inspection by using tools that travel inside the pipeline and scan the pipeline for anomalies
- Direct Assessment, where pipeline sections are exposed by excavating and inspected by utilizing non-destructive test (NDT) methods.

These inspections provide the means to identify if the pipeline is 'fit for service' using quantitative data that provides EGD with the ability to quantify the expected life of the asset. In general, this inspection Program provides information to make informed decisions to extend the service life of the asset. To validate the accuracy of the ILI data, EGD undertakes Integrity Digs where Non-Destructive Testing (NDT) is performed on exposed indications. Pipeline defects found during Direct Assessment are repaired before backfilling the exposed pipe. Anomalies identified during ILI, such as corrosion, cracks, mechanical damage, manufacturing defects, etc. are classified as:
- Requiring Immediate action
- Scheduled for investigation
- Monitored in accordance with EGD policies, which are developed based on the applicable codes, regulations, standards, and industry best practices.

Immediate features are mitigated immediately to a safe level based on Integrity Engineering Assessments and are then excavated, assessed, and mitigated as necessary within a prescribed window.
Scheduled features are excavated, direct assessed, and mitigated within a year of identification.
Monitored features that are expected to grow over time are monitored and investigated if necessary based on Integrity Engineering Assessment.

By mitigating immediate and scheduled features and targeting monitored features, the TIMP reduces the probability of pipeline failures, thus reducing the overall risk to the public, and ensuring reliable gas supply. The direct assessments and mitigations of Immediate and Scheduled features through excavations (Integrity Dig Program) adhere to prescribed timelines. This Program sets aside money to perform the required actions as per the Transmission Integrity

Management Program (TIMP). Immediate and scheduled features can pose a significant threat to the integrity of a pipeline. As per IMP manual, immediate features identified by ILI must be mitigated within 60 days of receiving the preliminary report and scheduled features within 1 year.

Assets:

Related Programs/BCs:

Compliance: Y

Solution Description:

SCOPE OF WORK: In line inspections are done on IMP pipelines as identified in the IMP manual. After in line inspections are completed, Integrity will determine the number and location of features that need to be inspected (exposed) and repaired (if required). At that point, child projects will be created for either Immediate Digs (issue must be addressed within 60 days) or Scheduled Digs (issue must be addressed within 1 year)

RESOURCES: These integrity digs will be issued by the Integrity department, planned by MP Planning and executed by MP Execution.

SOLUTION IMPACT: These digs will mitigate the threat poses by the identified features.

PROJECT TIMING: Immediate Integrity digs will be completed within 60 days of receiving preliminary report of the ILI while Scheduled Integrity digs will be completed within 1 year of receiving preliminary report of the ILI.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	0	$4,980,000	0

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$1,920,000	$0	$3,060,000	$0	$0	$0	$0	$0	$0	$0	$4,980,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,920,000	$0	$3,060,000	$0	$0	$0	$0	$0	$0	$0	$4,980,000
Retirement Cost											
Total Project Cost	$1,920,000	$0	$3,060,000	$0	$0	$0	$0	$0	$0	$0	$4,980,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10321
Estimate Class: Class 5

Project Information

Name: 2020 Steel Mains Replacement Program

Type: Enbridge Program **Start Year:** 2020

Asset Program: Main Replacement

Project Type: Replacement

Issue/Concern:

The Steel Main Replacement Program is both a reactive and proactive asset renewal program. Over the next ten years, the program will focus on reactively replacing steel mains that have experienced failure and integrity issues. The planned replacement will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks). Some examples of these assets are:

• Isolated Steel Headers: Steel gas mains on private property that supply more than one service such as shopping malls and condominiums. The common installation configuration is to connect a header station to a gas main to reduce the gas pressure and supply gas to the header network. The concern with steel headers is that they are isolated from the cathodic protection of the upstream steel gas main network, making headers more susceptible to cathodic disbondment, resulting in an accelerated corrosion rate.

• Bridge Crossings: Mains installed above-ground and affixed to a bridge structure. Mains on bridges are exposed to atmospheric elements and road salt during winter months, which could accelerate corrosion on steel mains, steel casing, and pipe hangers. Annual bridge crossing surveys identify faults on bridge crossings that trigger engineering assessments to review the faults and recommend risk mitigation measures, such as the replacement of components like pipe hangers or the entire bridge crossing if necessary.

• Exposed mains or insufficient depth of cover: Steel mains that are found to have insufficient depth of cover. Municipal roadwork and city development have altered the road grade and caused gas mains to be shallower than the original installed depth. To the extent possible, the depth of cover issues will be addressed by localized mitigation. In the event that a long distance of main is found to be shallow and the localized mitigation is not feasible, it will be mitigated by main replacement.

In addition to the reactive planned replacements of steel mains that have experienced failure and integrity issues, the program will also target other high-risk assets and proactively replace them before they reach EGD's intolerable risk region, such as the Kipling Oshawa Loop (KOL) system. The KOL system is a vintage steel HP network that runs through some of the high-density areas of the GTA downtown core. The KOL is known to have unrestrained compression couplings, shallow blow-off valve assemblies, and exhibit the adverse effects of stray currents from streetcars and the subway across the entire system. Given its location and the high consequence failure mechanism, such as pullout from compression couplings, the risk of the KOL vintage steel system ranks among the top of the steel main population.

Assets: Steel Mains

Related Programs/BCs: N/A

Compliance: N

Solution Description:

Scope of Work: Mandatory replacement of steel mains in poor condition or with integrity/compliance issues; projected spend profile based on leak projection, spend base year = 4-yr average of 2014-2017. The Steel Main Replacement Program will replace gas mains that exhibit signs of approaching end-of-life found in recent leak survey results and through field discovery of integrity issues (such as poor coating condition, severe corrosion, insufficient depth of cover or exposure, and leaks).

Resources: Operations crews, Planning, Construction contractor crews.

Solution Impact: Refer to Asset Plan section 5.2.5 for discussion on Distribution Steel Mains.

Project Timing & Execution Risks: The Project is a continuation of the Steel Main Replacement Program that begins in 2018. Identified execution risks: Resource capacity to design and execute, permitting, other external scheduling conflicts.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	10,616	$21,598,770	1

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$24,534,636	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,534,636
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$24,534,636	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,534,636
Retirement Cost	$0										
Total Project Cost	$24,534,636	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,534,636

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0R1					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years			R1	R0			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years		R0	R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**10088

Estimate Class: Class 5

Project Information

Name: NPS 20 Lake Shore Replacement (Cherry to Bathurst)

Type: Enbridge Project **Start Year:** 2019

Asset Program: Main Replacement

Project Type: Major Pipeline Project

Issue/Concern:

General Concerns

Vintage steel mains have shown signs of declining health due to the cumulative effects of poorly manufactured coatings, construction practices, latent third-party damages to pipe coatings, and the effect of stray currents from transit infrastructure (such as the subway and streetcars). The current failure projection model forecasts an exponential increase in the number of corrosion-related failures. The Quantitative Risk Assessment (QRA) and the 40-year risk projection show an aggressive increase in the safety risk associated with steel main failures. In addition to age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third-party damage in the following ways:

- Compression couplings
- Shallow blow-off valve assemblies that could be damaged during excavation activities
- Reduction in the original depth of cover
- Continuous exposure to road salt and seasonal ground movement on bridge crossing assets
- Lack of cathodic protection on pipe casings that could result in corrosion and could lead to the loss of containment
- Manufacturing defects associated with seam welds and fittings that could result in a loss of containment due to prolonged stress and corrosion
- Latent damages to pipe coatings that were never reported to EGI for repair and became active corrosion sites, resulting in accelerated corrosion and potentially loss of containment

Site Specific Concerns: The NPS 20 Lake Shore Replacement project from Cherry to Bathurst addresses vintage steel mains installed in 1954. This project was assessed using Asset Health Review (AHR) methodology, QRA, tacit knowledge from internal stakeholders and in-line inspection (ILI)/Integrity dig results. In addition to the declining health demonstrated by vintage steel mains, this pipeline is part of the KOL system in the Toronto area, known to have a number of features that make it more susceptible to accelerated degradation and/or higher risk of third party damage. These features include but are not limited to:

• Compression couplings on mains and services

• Reduced depth of cover

- Shallow blow-off valves
- Lack of cathodic protection
- Live stubs
- Stray current from hydro infrastructure
- Possibly contaminated soils

This assessment identifies risk results that exceed EGI's risk threshold and supports the recommendation that this section of the NPS 20 pipeline requires replacement. The NPS 20 Lake Shore Replacement from Cherry to Bathurst project is a size-for-size replacement of NPS 20 HP steel main on Lake Shore Boulevard. This project addresses a section of the KOL pipeline identified to be above EGI's acceptable risk threshold, scheduled for execution in the first half of the 10-year Asset Management Plan. The replacement of the NPS 20 Lake Shore vintage steel main helps address known pipeline integrity and operational field concerns by proactively replacing steel mains approaching intolerable risk due to failing pipes or pipes in poor condition. This results in the prevention of the future failures of these critical distribution system assets.

Assets: This project will replace approximately 4.4 km of NPS 20 HP steel main with new pipe and will retire approximately 4.5 km of the existing NPS 20 HP gas main.
Related Programs/Business Cases: BCs 10087, 10026, 10121, 10122, 10123

Compliance: N

Solution Description:

Scope of Work: This project is a size-for-size replacement of the existing NPS 20 HP steel main on Lake Shore Blvd from Cherry to Bathurst. This work includes approximately 4850 m of NPS 20 and 500 m of NPS 20 on Mill St, it runs on Lake Shore Blvd from Parliament St to Bathurst.

Resources: 2021 - OTC and would be bid on by external contractors

Solution Impact: Main replacement project identified by Asset Management - Pipelines as high-priority. Replacement is required due to age, pipeline condition and risk assessment results, further investigation was completed in 2018 to collect additional pipe condition data to assist in the planning, engineering and risk components. This confirmed the timing for execution of this replacement project for 2021.

Project Timing & Execution Risks: moratoriums, 3rd party developments, Gardiner realignment and required easements.

Related BCs: 7179 2017-2018.

Solution Options

Options				
Option Name	**Selected Option**	**Risk Mitigated**	**Total Net Direct Capital**	**LRROI**
Option 1	N	480,772	$150,225,000	5
Option 2	Y	480,772	$165,536,863	5

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$282,750	$3,500,000	$130,613,276	$31,132,437	$8,400	$0	$0	$0	$0	$0	$165,536,863
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$282,750	$3,500,000	$130,613,276	$31,132,437	$8,400	$0	$0	$0	$0	$0	$165,536,863
Retirement Cost				$2,800,000							$2,800,000
Total Project Cost	$282,750	$3,500,000	$130,613,276	$33,932,437	$8,400	$0	$0	$0	$0	$0	$168,336,863

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years					R2		
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years				R2			
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years					R2		
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years					R2		
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Pipe **Business Case ID:**9521
Estimate Class: Class 5

Project Information

Name: Sideline 16 and Brock Pressure Control Station (part of pipe Reinforcement)

Type: Enbridge Project **Start Year:** 2017

Asset Program: System Reinforcement - Pipe

Project Type: Reinforcement (Pipe & Station)

Issue/Concern:

Due to new customer additions that are expected in the years to come, a pressure elevation and a pressure control station is needed to achieve the pressure elevation. The elevation will be on the Pickering Gate Station (south feed) from 400 to 500 psi. Pressure increase to terminate at this new control station at Sideline 16 north of Taunton Rd.

Compliance: N

Solution Description:

Pressure regulation is required to accommodate an upcoming pressure elevation from 400psi to 500psi. This is required for current conditions and system growth.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	N	0	$2,285,022	0
Option 2	Y	0	$2,173,002	0

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$28,093	$801,461	$409,348	$934,100	$0	$0	$0	$0	$0	$0	$2,173,002
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$28,093	$801,461	$409,348	$934,100	$0	$0	$0	$0	$0	$0	$2,173,002
Retirement Cost											
Total Project Cost	$28,093	$801,461	$409,348	$934,100	$0	$0	$0	$0	$0	$0	$2,173,002

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Real Estate and Workplace Services **Business Case ID:**3639
Estimate Class: Class 5

Project Information

Name: Kennedy Road Expansion

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern:

Overall, the existing building at the Kennedy Road facility is too small to meet current EGD standards. The separation of offices and warehouse into two separate buildings is not convenient for staff and causes operational and workplace difficulties and inefficiencies. The configuration of site functions and circulation is inefficient. The yard area is too small to meet current EGD standards. Building expansion on the same property will further reduce the size of the yard area and will cause additional pressure on parking and circulation. Based on the site deficiencies and space limitations, relocation to another property is recommended. Although the Facility Condition Index (FCI) and Adequacy Index (AI) graph indicates recommendations to maintain and repurpose the existing facility, the site deficiencies, including space limitations and inefficiencies, will prevent the option of maintaining the existing building on the same property.

Physical Obsolescence: The acceptable EGD standard for the physical condition is a FCI of 0 to 5%. The current FCI of the facility based on this study is 6.51%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.

Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility AI is 95%. Based on the FCI/AI graph, the current recommendation for the existing facility is to repurpose to accommodate current EGD standards.

Functional Obsolescence – Site: The site does not meet operational requirements for size and vehicular circulation. Access and exit from Kennedy is difficult and poses operational inefficiencies. The yard size is smaller than EGD standard yard size requirements. The current yard size is 1.3 acres. EGD standard yard size is 2.5 acres. The existing building requires expansion by approximately 11,000 square feet to meet the need for current staff and EGD functional requirements. Building additions on the property entail further reduction in the yard and parking areas.

Asset: 3157 Kennedy Road, Scarborough, ON.
Related Program: N/A

Compliance: N

Solution Description:

This Project entails purchasing the adjacent property (approximately 2 acres), demolishing the existing buildings on site, and building a new 26,000 square foot building comprising of administration, warehouse, welding and fabrication facilities. The Project will correct operational and workplace inefficiencies, using less energy and emit less greenhouse gases on the combined site. This strategy will leverage current site improvements and keep land acquisition costs to a minimum by joining the currently vacant neighboring property. The service life of the new facility will be 25-40 years.

The assets in scope are located at 3157 Kennedy Road, Scarborough, ON. The nature of work includes development of the adjacent property and construction and fit-up of a new building. The Project duration is 36 months as outlined below:
0 – 3 months: Programming, design development
3 – 6 months: Site acquisition
6 – 12 months: Site plan agreement, permit & tender documents, permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 28 months: Construction
28 – 30 months: Fit-up and occupancy
30 – 36 months: Demolition of old building and remaining site activity

Expenditures
The total cost for the Project is $22.2 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and estimated land values are based on marketplace comparisons. The Project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The Project costs are based on a Class 5 estimate.
Resources
Professional resources for design and engineering will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services for the execution of similar projects.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	1,281,711	$21,700,000	90
Option 2		1,281,711	$21,900,000	90

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$6,600,000	$6,500,000	$8,600,000	$0	$0	$0	$0	$0	$0	$0	$21,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$6,600,000	$6,500,000	$8,600,000	$0	$0	$0	$0	$0	$0	$0	$21,700,000
Retirement Cost			$500,000	$0							$500,000
Total Project Cost	$6,600,000	$6,500,000	$9,100,000	$0	$0	$0	$0	$0	$0	$0	$22,200,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year						R0	
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**1796
Estimate Class: Class 5

Project Information

Name: Brampton Operations Centre Alterations

Type: Enbridge Project **Start Year:** 2016

Asset Program: Furniture / Structures & Improvements

Project Type: Building Improvements

Issue/Concern:

The Colony Court office in Brampton is an owned property and has served Central Region West for over 10 years. The property is in relatively good physical condition but does not meet functionality/utilization requirements. In addition, the facility does not meet current building standards and operational requirements and the office space and yard is no longer sufficient to accommodate the current and future staffing needs of the operation. The majority of the furniture does not meet non-functional requirements.

Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 11.02%; therefore the physical condition of the facility does not meet EGD standards.

Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 49%. Based on the FCI/AI graph the current recommendation for the existing facility is to repurpose and invest to accommodate current EGD standards.

Functional Obsolescence – Site: The site does not meet operational requirements for vehicular circulation. The yard has only one point of access. The existing building requires expansion by approximately 9,000 square feet to meet the need for current staff and EGD functional requirements. Building additions on the property will entail reduction in the yard and parking areas, however the yard size will still be considered adequate based on current operations. Overall the existing building is too small to meet current EGD standards. The current building is approximately 14,250 square feet. An additional 9,000 square feet is required to accommodate office and industrial space.

Asset: 6 Colony Court, Brampton, ON.

Related Program: N/A

Compliance: Y
Solution Description:

The Project entails correcting the physical and functional deficiencies by expanding the existing facility on the existing site. The site can be reconfigured to correct its functional inefficiencies and the existing structure can be expanded and reconfigured to meet current Enbridge standards. A 9, 000 square foot expansion to the building comprising of administration, warehouse, welding and fabrication facilities will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases. This expansion will extend the asset useful life by 25 to 40 years.

The assets in scope are located at 6 Colony Court, Brampton, ON. The nature of work for the Project includes site improvements and facility expansion. The Project duration is 24 month as described below:
0 – 3 months: Programming and design development
3 – 9 months: Site plan agreement, permit and tender documents
9 – 12 months: Permit and tender process
12 – 14 months: Contract award and winter contingency as required
14 – 22 months: Construction
22 – 24 months: Fit-up and occupancy

Expenditures
The total cost for the Project is $10.9 M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD projects. The Project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. The Project costs are based on a Class 5 estimate.

Resources
Professional resources for design and engineering will be contracted from the marketplace. Historically, EGD has retained architectural and engineering consulting services for the execution of similar projects.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	454,565	$9,325,000	74
Option 2		454,565	$8,240,000	84

Cost

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Direct Capital Cost	$145,000	$280,000	$2,000,000	$100,000	$4,800,000	$2,000,000	$0	$0	$0	$0	$9,325,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$145,000	$280,000	$2,000,000	$100,000	$4,800,000	$2,000,000	$0	$0	$0	$0	$9,325,000
Retirement Cost	$0		$1,135,000		$500,000						$1,635,000
Total Project Cost	$145,000	$280,000	$3,135,000	$100,000	$5,300,000	$2,000,000	$0	$0	$0	$0	$10,960,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Real Estate and Workplace Services **Business Case ID:**22004
Estimate Class: Class 3

Project Information

Name: TIS Technology and Innovation Lab

Type: Enbridge Project **Start Year:** 2019

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern:

The Digital Hub/Lab is a new way of creating high value applications that will generate the most impact for EGI leveraging our new tech stack Resource the Digital Hub with the right skills covering design, data science, product management, data architecture, system architecture, and agile methodologies.

Assets: VPC

Related Program (if applicable): N/A

Compliance: N

Solution Description

Scope of Work: New Digital Hub space and technology to support a new way of working through a space that reinforces its strategy.

Resources: External professional resources for design and engineering along with a construction company will be contracted for the Project. Historically, EGI has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Impact: Assets in scope: 500 Consumers Rd. Toronto, ON. The nature of work is interior renovation and furnishings and Technology.

Project Timing and Execution Risks:
The total Project duration is 6 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 4 months: Permit and tender documents, Award, permit and tender process
4- – 6 months: Construction
7 month: Fit-up and occupancy

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	0	$1,000,000	0

Cost

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Direct Capital Cost	$0	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$1,000,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$0	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$1,000,000
Retirement Cost		$100,000									$100,000
Total Project Cost	$0	$1,100,000	$0	$0	$0	$0	$0	$0	$0	$0	$1,100,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Real Estate and Workplace Services **Business Case ID:**3634
Estimate Class: Class 4

Project Information

Name: VPC-1

Type: Enbridge Project **Start Year:** 2020

Asset Program: Furniture / Structures & Improvements

Project Type: Structures & Improvements

Issue/Concern:

The VPC facility houses the majority of company employees. It is an owned facility that is currently undergoing renovations to address the physical condition and capacity concerns, as well as to replace legacy furniture and finishings. The first and second floors have not yet been renovated.

Physical Obsolescence: The acceptable EGD standard for the physical condition is a Facility Condition Index (FCI) of 0 to 5%. The current FCI of the facility based on this study is 5.59%. Therefore, the physical condition of the facility does not meet EGD acceptable standards.

Functional Obsolescence – Building: The acceptable EGD standard for the functional condition is 0. A functional condition between 0 and 49% is considered correctable at the current location. The current facility Adequacy Index (AI) is 11% which is considered correctable at the current location, without consideration of other factors including adequacy of land size and the FCI.

Functional Obsolescence – Site: The site area and parking provided are generally in compliance with EGD requirements.

Asset: First Floor, 500 Consumers Rd. Toronto, ON.

Related Program: N/A

Compliance: N

Solution Description:

The Project corrects physical and functional deficiencies on the 1st floor of the tower by renovating and renewing the existing space. The current site has capacity to meet EGD functional requirements. Renovations to the building will correct operational and workplace inefficiencies, using less energy and emitting less greenhouse gases.
The interior renovation will extend the asset useful life by 10 to 15 years.
The assets in scope are the 1st floor at 500 Consumers Rd. Toronto, ON.

The nature of work is interior renovation and furnishings. The total project duration is 14 months and broken down as follows:
0 – 2 months: Programming and design development
2 – 5 months: Permit and tender documents
5 – 7 months: Award, permit and tender process
7 – 12 months: Construction
12 – 14 months: Fit-up and occupancy

Expenditures:
The total cost for the Project is $5.0M net capital which includes a working construction cost contingency of 15%. Construction costs are determined based on historical EGD project costs and land values are determined using marketplace comparisons.
The project also leverages national pricing agreements with furniture, walls, and flooring manufacturers. Project costs are based on a Class 5 estimate.

Resources:
External professional resources for design and engineering along with a construction company will be contracted for the project. Historically, EGD has retained architectural and engineering consulting services and general construction contractors for the execution of similar projects.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	524,865	$4,700,000	107

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$4,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,700,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,700,000
Retirement Cost	$350,000										$350,000
Total Project Cost	$5,050,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,050,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year					R0		
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years	R1						

Asset Class: Stations **Business Case ID:**14803
Estimate Class: Class 5

Project Information

Name: Station B Filter Install

Type: Enbridge Project **Start Year:** 2020

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

During pigging operations on the Parkway to Ashtonbee GTA line, debris was found in the PEC Generators causing an equipment malfunction and system shutdown at the PEC PowerPlant.

Asset: Station B Feeder Station Assets

Related Program: N/A

Compliance: N

Solution Description:

This is a new project, identified in 2019. New NPS 20 in line filter to be installed at Station B to reduce associated debris risk during in-line inspection operations as per the seven-year years schedule. Additionally, the NPS 36 Parkway North pipeline and NPS 26 Keele CNR pipelines were inspected in 2017 so they would be coming up for inspection prior to the NPS 30 DVP pipeline. This will increase inspection associated with Station B. The main purpose of the filter is to prevent any debris going downstream from Station B to our large volume customer at PEC.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	4,649	$1,200,000	6

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$1,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,200,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,200,000
Retirement Cost											
Total Project Cost	$1,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,200,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years				R0			
Once in 100 to 1000 years							
Once in 1000 to 10000 years				R1			
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years	R0						
Once in 100 to 1000 years							
Once in 1000 to 10000 years	R1						
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years				R0			
Once in 100 to 1000 years							
Once in 1000 to 10000 years				R1			
Once in 10000 to 100000 years							

Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years				R0			
Once in 100 to 1000 years							
Once in 1000 to 10000 years				R1			
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3505

Estimate Class:

Project Information

Name: 2020 Capacity Related Rebuilds

Type: Enbridge Program **Start Year:** 2020

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

To maintain a reliable and healthy network, stations require rebuild to meet increased capacity needs due to organic growth. Some of these stations may be in good operating condition, but may just be undersized and cannot require the appropriate flows.

Compliance: N

Solution Description:

The need for this new program was identified in 2019. This budget is for seven to eight full district station rebuilds and additional funds for orifice and regulator head changes.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	55,078	$400,000	0

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$400,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$400,000
Retirement Cost	$210,000										$210,000
Total Project Cost	$610,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$610,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0R1				
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0R1						
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**1775

Estimate Class: Class 5

Project Information

Name: Campbell St Station, Collingwood

Type: Enbridge Child Project **Start Year:** 2017

Asset Program: Integrity Initiatives - Stations

Project Type: Integrity Retrofit

Issue/Concern:

Existing station footprint could not facilitate future inline inspection work. Receiver will need to extend outside of station onto adjacent private property. New property owner plans to build hostel on the property which might not be able to accommodate EGD's temporary working space needs for any ILI activities beyond 2018/2019.

New station must be in place by 2024 (or 6 years from the next successful ILI)

Permanent relocation of station to a location upstream from current location:

• A land of at least 30mx40m to accommodate remove pigs from the receiver and room for parking on site to support current operations
• A new station will be rebuilt in the new location to meet current and future flows.
• A boiler and heat exchanger system to preheat the gas
• NPS 6 ST IP and/or NPS 6/8 XHP main extension (length TBD) is required to tie the new site tie back to the existing network.
• The section of NPS 8 XHP downstream of the new station location will not be replaced and will be inspected using a crawler tool. Inspection using crawler tool would impact the O&M budget of approx. $200,000 every seven-year cycle (or whenever this pipeline needs to be inspected).

Project moved from Pipe to Stations asset class.

Compliance: N

Solution Description:

2017-2020 Scope: Planning phase - Land Department to explore options to securing a larger station property that could accommodate station infrastructure as well as launcher/receiver. This could be done through acquiring new property to relocate the station, or by negotiating with new property owner to secure permanent easement adjoining the existing station property.

2020-2025 Scope: Design and construction execution of a relocated receiver site (and pipe crawler launcher as needed) in advance of the next ILI. Next ILI is tentatively targeted for 2026 - pending a successful ILI in 2019.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	0	$4,062,524	0

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$80,000	$19,435	$10,000	$20,000	$1,930,820	$2,002,269	$0	$0	$0	$0	$4,062,524
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$80,000	$19,435	$10,000	$20,000	$1,930,820	$2,002,269	$0	$0	$0	$0	$4,062,524
Retirement Cost	$0										
Total Project Cost	$80,000	$19,435	$10,000	$20,000	$1,930,820	$2,002,269	$0	$0	$0	$0	$4,062,524

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							

Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**7768
Estimate Class: Class 5

Project Information

Name: JONESVILLE FEEDER

Type: Enbridge Project **Start Year:** 2018

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

Jonesville Feeder Station is located in a fenced compound in the City of Toronto, Ontario, within a hydro utility corridor, in an urban area, and in close proximity to several high-rise apartment complexes. This station accepts natural gas from an Enbridge XHP pipeline and provides supply to a HP network, through components within the Measurement, Pressure Control, Heating, and Telemetry systems. This station supplies natural gas to approximately 85,000 customers in the Toronto and Scarborough area.

The following issues have been identified at this station:2019:
VALVE & PIPING: The existing valves at this site have experienced issues in performance and operation of the valves. Maintenance has been performed to attempt to remediate the valves, however, the valves have deteriorated to the point where the reliability is no longer acceptable.
PRESSURE CONTROL: The configuration of the existing regulators are double boot, posing an undesired higher risk and high associated ongoing maintenance costs, the existing valves no longer seal properly, making inspection of the station components difficult to perform. The existing controllers are obsolete and non-standard components.
BACKUP GENERATOR: A 20+ kW generator with a 30 amp configuration is required as a back-up power source for the boiler building.
METHANE + CO DETECTOR: Combination methane and CO detectors need to be installed within the boiler room
HYDRO METER: The hydro meter to the property needs to be replaced as the bonding screw was stripped when originally installed and has been repaired with a temporary solution.
TELEMETRY & ELECTRICAL: The existing RTU is obsolete and no longer manufactured. As such it is required to be upgraded to current standards along with new communications equipment in order to eliminate cyber security threats. Replacement in 2019 prevents programming the regulation run actuation equipment twice (once in 2019, then again when the RTU is replaced)

2020:
STATION LIGHTING: Upgrades are required in order to provide adequate security and work lighting
TELEMETRY : The radio antenna is obsolete and Telemetry is not permitted to climb this style of tower anymore, so a new antenna tower is necessary.
FENCING: The height of the existing fencing has been identified as being lower than typical

(especially when snow banks are present) posing a security risk. It is requested to consider increasing the fence height, expanding the fencing perimeter from inside structures and/or increase measures to prevent intruders (i.e. wire barbing)

Compliance: N

Solution Description:

Scope of Work

2019 scope: Inlet/Outlet valves on both regulator runs will be replaced, existing 8" Kerotest Gate valves will be replaced with new 8" ball valves (4).
Remainder of scope to be completed later in the plan.
Pipes & Valves: The bypassing inlet and outlet valves will be addressed by replacing the valves with new Cameron ball valves.
Heating System: The obsolete Delta V controller will be replaced with new Honeywell controllers.
Telemetry & Electrical: The existing RTU cabinet and panel will be replaced with a new Control Wave unit. The telemetry and electrical systems will be brought up to current standards and may include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator or TEG upgrades, modem and firewall upgrades, and station lighting upgrades.

Solution Impact: TBD

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing & Execution Risk:
Planning in Year 1, Execution in Year 2 / Execution Risk - Weather impacts, Resource availability, Procurement, etc.

Solution Options

Options

Option Name	Selected Option	Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	Y	16,306	$1,354,711	15

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$4,000	$1,142,896	$207,815	$0	$0	$0	$0	$0	$0	$0	$1,354,711
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$4,000	$1,142,896	$207,815	$0	$0	$0	$0	$0	$0	$0	$1,354,711
Retirement Cost											
Total Project Cost	$4,000	$1,142,896	$207,815	$0	$0	$0	$0	$0	$0	$0	$1,354,711

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R1				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year	R0						
Once in 1 to 10 years	R1						
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**8567

Estimate Class: Class 5

Project Information

Name: ST. JOHN SIDEROAD FEEDER

Type: Enbridge Project **Start Year:** 2018

Asset Program: Gate & Feeder Station

Project Type: Gate Stations

Issue/Concern:

The property on which St. John's Sideroad feeder station currently sits is insufficient for operation. It is located adjacent to a residential property and the area classification extends onto the adjacent private property. The boiler building is located in a hazardous area classification and this non-compliance needs to be remedied. Road widening of St. John's Sideroad currently has the sidewalk encroaching on our station. A land sale agreement with York Region was completed in 2016 and requires movement of the electrical meter. As the area classification issue risks shutdown of the station by the Electrical Safety Authority, EGD is postponing the movement of the electrical meter (onsite) pending a new land purchase for relocation of the entire station. As a result of station relocation, a complete rebuild will be required. Maintenance on the boiler system piping, pumps and gauges, which are old and obsolete, suggest that the heating system needs to be replaced regardless of station relocation. The heating system is already undersized for the current demand. The FL regulators are difficult to work on due to their weight and the ergonomic restriction in a cramped building. These are to be replaced and upgraded. The old RTU 3330 telemetry system needs to be upgraded, including the backup power generator which is old and obsolete. Station updated in 2006. Generator installed in 2003. Boilers installed in 2003. Source records do not indicate capacity issue with regulators.

Asset: Station ID: 2944180

Related Program: N/A

Compliance: Y

Solution Description:

2019 spend focused on land purchase of $1.2M based on estimated land value of preferred property location. Uncertainty remains if the landowner will accept our offer to sell.

A new station and all supporting infrastructure will be constructed on a newly acquired parcel of land. The existing station will be removed from service and abandoned appropriately.
The new location will be in close proximity to the existing station just off of St. John's Sideroad, East of Leslie and West of the 404.

Pipes & Valves: All existing piping will have to be built as part of the station relocation. This includes station isolation and bypass valves as well as isolation valves required for the heating system and regulator runs. A new fuel gas station will be required that includes measurement of fuel gas consumption by the boilers and the generator.

Heating System: A new boiler and heat exchanger type heating system will have to be installed for gas preheat and all area classification requirements will be met.

Pressure Control: New regulator runs will have to be installed as the existing FL regulators are difficult to maintain.

Odourant System: No odourant system is required as this is a Feeder Station.

Telemetry & Electrical: The existing RTU panel will be replaced with a new unit in a new electrical building to meet area classification requirements. A new RTU cabinet and panel will be replaced with a Control Wave unit. The telemetry and electrical systems will be brought up to current standards and will include methane and CO sensors and monitoring, station wiring upgrades, electrical service upgrades, station grounding, telemetry tower upgrades, UPS installation, generator installation, modem and firewall upgrades, station lighting upgrades, and weather station installation/replacement.

Measurement: A new mass flow meter will be installed and connected to SCADA so that Gas Control can monitor station flows, pressures, and temperatures.

Compliance & Others: New land will have to be acquired to allow for the station relocation and there are currently two sites that are favoured. Either of these options will require significant civil work to ensure a suitable grade on which the station will sit and allow for adequate run off capabilities. The new station will require additional XHP and HP pipe to be installed to connect appropriately to the existing network. The location will determine the length of pipe needed to be installed.

$1.2 million allotment for Land acquisition.

Solution Impact: TBD

Resources: Company crews, contractor labour and third-party vendor suppliers

Project Timing & Execution Risk: Planning in Year 1, Execution in Year 2 / Execution Risk - Weather impacts, Resource availability, Procurement, etc.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 1	N	27,903	$4,421,959	9
Option 2	Y	30,413	$4,879,370	10

Cost

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Direct Capital Cost	$20,000	$1,200,000	$3,659,370	$0	$0	$0	$0	$0	$0	$0	$4,879,370
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$20,000	$1,200,000	$3,659,370	$0	$0	$0	$0	$0	$0	$0	$4,879,370
Retirement Cost											
Total Project Cost	$20,000	$1,200,000	$3,659,370	$0	$0	$0	$0	$0	$0	$0	$4,879,370

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years				R2			
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year			R0				
Once in 1 to 10 years		R2					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year				R0			
Once in 1 to 10 years			R2				
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year		R0					
Once in 1 to 10 years		R2					
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Stations **Business Case ID:**3455

Estimate Class: Class 5

Project Information

Name: Harmer District Station

Type: Enbridge Project **Start Year:** 2017

Asset Program: Station Rebuild

Project Type: Station Replacement Program

Issue/Concern:

EGD has a XHP to IP district station located inside a building. The regulator station is located in the garage of a house and is not to current EGD standards. The station is located close to a school, hospital, shopping complex, and dense residential population.

Integrity is planning an inline inspection of the Vital NPS 12 XHP (Network 6582) and additional space is required for a receiver.
2017 and 2018 are Planning Only.

Compliance: Y

Solution Description:

Relocate Harmer District Station to Tunney's Pasture and complete rebuild as part of a system reinforcement. System reinforcement required for customer load increase request at Cliff Street and potentially required for future development at Tunney's Pasture.

Solution Options

Option Name	Selected Option	Options Risk Mitigated	Total Net Direct Capital	LRROI
Option 2	N	0	$4,952,207	0
Option 3	N	0	$1,884,106	0
Option 3		0	$6,744,443	0
Option 4	Y	0	$13,097,928	0
Option 4		0	$1,884,106	0

Cost

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Direct Capital Cost	$0	$9,000	$10,000	$0	$13,078,928	$0	$0	$0	$0	$0	$13,097,928
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$0	$9,000	$10,000	$0	$13,078,928	$0	$0	$0	$0	$0	$13,097,928
Retirement Cost					$871,929						$871,929
Total Project Cost	$0	$9,000	$10,000	$0	$13,950,857	$0	$0	$0	$0	$0	$13,969,857

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years							
Once in 10 to 100 years							
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Asset Class: Storage **Business Case ID:**8893
Estimate Class:

Project Information

Name: Integrity Digs

Type: Enbridge Program **Start Year:** 2020

Asset Program: Integrity Digs - Storage

Project Type: Integrity Digs

Issue/Concern:

Pipeline integrity monitoring is implemented to mitigate threats acting on high-stress pipelines, in order to reduce the probability of a loss of pressure containment acting on these pipelines. Threat mechanisms are assessed to determine the probability of a loss of containment event. Threat mechanisms are assessed in accordance with the methodology of ASME B31.8. The main threat is internal/external corrosion, which is a time-dependent threat mechanism. Mitigation is accomplished using ILI and investigative digs, completed at short enough time intervals to prevent corrosion from causing a leak or rupture of the pipeline. ILI can also find: latent third party damages, stress corrosion cracking, and impacts related to equipment failure, operator error, latent manufacturing/construction defects and environmental factors on the pipelines. Many of these threat mechanisms are not considered primary risk drivers.

Assets
Applicable assets are limited to location class 1 and 2 pipelines that operate at greater than 30% SMYS.

Related Program
The proposed project is a named project within the 10 year plan.

Compliance: Y

Solution Description:

*BLANKET
LM:P/L,Lat-Invest'v Digs (2020)

Scope of Work
Solution/Cost Basis: Following review of the results of a previous year's inspection, pipeline sections may be identified for further inspection or repair. On average this includes 4 investigative digs. Each dig includes excavation of a section of pipe, followed by inspection and may result in the application of a clock spring or the anomalies may be cut out and replaced. Repairs typically include: line research, laying of plates, daylight pipe and other utilities in work area, inspect pipe (NDE), determine appropriate resolution to anomaly, install clock spring or

new pipe material (replacing pipe section may result in large delays due to material lead times. stocked pipe may be available but its usage can not impact stock reserved for emergency repairs. Any stock pipe must be replaced), survey modifications, perform additional NDE as required, backfill pipe, compaction testing, complete quality package, redlines, as built and commissioning.

Resources:
Internal resources: Engineering, Document Control, Operations, Execution, Finance, Contracts, Warehouse and Safety).
External Resources: Engineering consulting firm, Site Inspector, Construction Contractor & Sub Contractors, Non-Destructive Testing Contractors, Survey Contractors, Concrete Testing / Ground Testing, Environmental Contractors

Solution Impact:
Completing this project enables EGD to fulfill compliance requirements. Project will ensure anomalies are repaired, pipe is in working condition and there is no need to derate pipelines. Investigation of anomalies assists in validating ILI data and confirming the reliability of our systems.

Project Timing and Execution Risks:
For integrity digs on immediate features, the work will performed within 60 days of notification to the field executing group. For integrity digs on scheduled features, the mitigation time requirement is within one year of the notification to the executing group.
Planning in Year 1
Execution in Year 2 (~*~)
Execution Risk - Material availability/lead times, Pool availability, weather delays. The purchase of pipe, fittings, and valves is required, and could be subject to lengthy lead times.

Solution Options

		Options		
Option Name	**Selected Option**	**Risk Mitigated**	**Total Net Direct Capital**	**LRROI**
Option 1	Y	1,058,652	$1,020,000	2,730

Cost

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
Direct Capital Cost	$1,020,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,020,000
Rebillable Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Net Direct Capital Cost	$1,020,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,020,000
Retirement Cost	$80,000										$80,000
Total Project Cost	$1,100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,100,000

Total Risk:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years						R0	
Once in 10 to 100 years					R1		
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Safety:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years					R0		
Once in 10 to 100 years					R1		
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Financial:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years					R0		
Once in 10 to 100 years					R1		
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

Customer:

	<100	100 to 1K	1K to 10K	10K to 100K	100K to 1M	1M to 10M	>=10M
Once or more a year							
Once in 1 to 10 years					R0		
Once in 10 to 100 years					R1		
Once in 100 to 1000 years							
Once in 1000 to 10000 years							
Once in 10000 to 100000 years							
Once in 100000 to 1000000 years							

3.4 APPENDIX D: LIST OF UNION RATE ZONES PROJECT DESCRIPTIONS

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Project: NPS 48 Kirkwall to Hamilton

Project Description
This project will deliver the installation of a new Nominal Pipe Size (NPS) 48 pipeline between the existing Kirkwall valve site and Hamilton valve site. The new pipeline will be 10.2 km. The existing inline inspection facilities at the Hamilton Valve site will be removed and moved to Kirkwall Valve site. Modifications to both valve sites will occur to accommodate the expansion. Incremental capacity is required on the Dawn Parkway System to meet infranchise growth and customer demand bids received in the 2021/2022 Dawn Parkway Open Season.

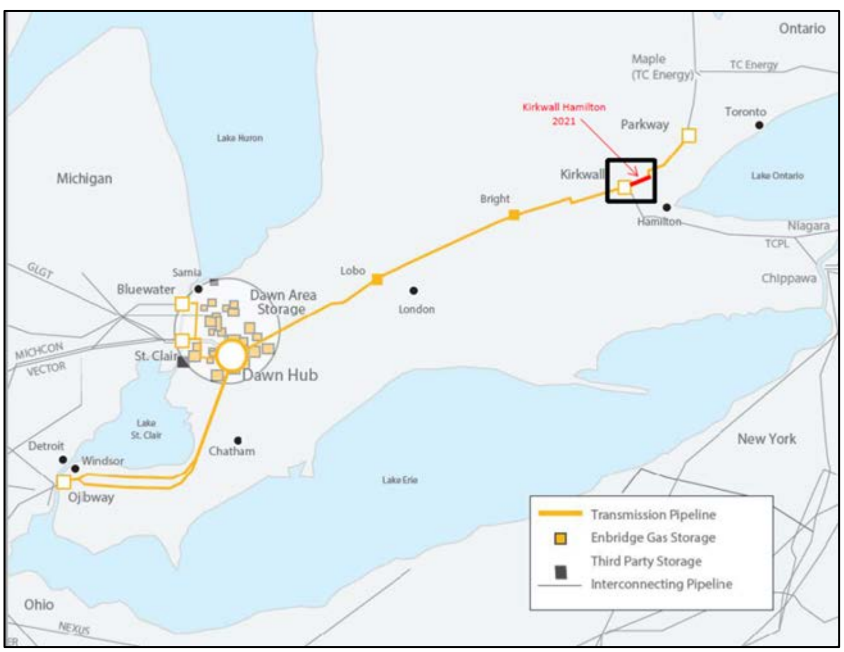
Project Scope: This new project, with a budget of $4.6 million in 2020, was not identified at the time of AMP because incremental demand was not identified until the closing of the 2021 and 2022 Dawn Parkway open season that closed November 16, 2018.

Expansion of the Dawn Parkway system provides customers with increased access to diversity, reliability and security of supply of the Dawn Hub.

Expenditures: The total cost of the project is $184,060,000.

Resources: Project Management will be completed by Enbridge Gas Inc. resources while all construction activities will be completed by a Prime Contractor.

Leave to Construct: A Leave to Construct application will be filed with the Ontario Energy Board by year end in 2019.



Project: Payne New Injection/Withdrawal Well

Project Description
This project is intended to recover lost design day deliverability at the Payne pool. The deliverability of the Payne pool has declined by 70 MMCFD due to the abandonment of one injection/withdrawal well (P8) and the relining (with a smaller casing) of four injection/withdrawal wells (P14, P15, P16, P18). This project will drill one new vertical injection/withdrawal well and connect it to the existing gathering system. The new injection/withdrawal well will recover all the lost deliverability (70MMCFD) with an anticipated design day deliverability impact of 12 MMSCFD.

Project Scope:
Some pre-work needs to be completed in 2019. Construction of the well pad, and a HAZOP study will be completed in August to October of 2019. This pre-work is estimated to cost $80,000. The well will be drilled in July to August 2020.

If this project is rejected or deferred, deliverability on the legacy Union system is limited to availiable capacity. Enbridge (legacy Union) will forego the benefits (potential sales). Potential deliverabilty sales are estimated to be $368,000 per year. There are no alternatives to regaining the lost deliverability from the Payne pool. The relining and abandonments were undertaken to meet CSA Z341 code.

Expenditures: The total cost of the project is $2,468,182.

Resources: This project will be internally managed by EGI staff and construction work, such as well drilling and new pool piping installation, will be performed by contractors.

Leave to Construct: A Leave-to-Construct and a filing to the MNR is required for this project. The OEB filing submission is targeted for Q4 2019.

Project: Fleet Light and Medium Duty Vehicles

Project Description
This Project provides the Union Rate Zone with the necessary fleet vehicles to safely and efficiently run its business operations. The goal of the Project is to maintain the integrity of all fleet assets for safe and reliable operation. This ongoing replacement strategy optimizes the UGL Fleet and align with Corporate Vehicle Replacement Guidelines that considers fleet safety, reliability and economical operation.

The direct impact is reduced O&M repair and maintenance costs, and improved driver safety.

Project Scope
Light and medium duty vehicles are required to replace existing vehicles that are in poor operating condition.
For 2020, $3.0 M capital advanced to 2019 and there was a reduction of $2.0 M to align the fleet management strategy across EGI.

Expenditures: The total cost of the project for 2020 is $7,000,000.

Resources: Fleet and Equipment staff.

Leave to Construct: Not applicable.

Project: Dawn Dehydration Plant Tank Replacement

Project Description
This project will deliver a replacement of the Dawn Dehydration Plant Condensate Process Tank with a double-walled tank and the ability to identify a breach of either the inner or outer wall.

The existing process tank is a 92,000-liter buried fibreglass single-walled tank with a blanket gas system. External pressure on the tank wall could lead to cracking and small tank leaks that would not be detectable. The tank was installed in 2005. Corrosion is present on the tank and growing in depth over time.

If this project is deferred, cracking of the fibreglass tank through external ground pressue could result in an environmental spill and the inability to operate the Dawn Dehydration Plant.

Project Scope
The scope includes removal of the existing tank, design, procurement, and installation of a new double walled tank in 2020. Due to proximity to surrounding civil infrastructure, additional support and shoring is required during the excavation.

Expenditures: The total cost of the project is $684,300.

Resources: Contractor resources will be used for this project.

Leave to Construct: Not applicable.

Project: Dawn Aux 3 Boiler Replacement

Project Description

The Dawn Aux 3 boiler system is comprised of a single boiler that heats the compressor building and also supplies heat to Dawn Plant D fuel gas. The boiler, installed in 1989, has had burner tube and refractory repairs. Polaire, the third-party firm that maintains the boiler, has indicated that the boiler is reaching end-of-life and repair parts are no longer available. In event of a major failure, the boiler and Plant D would be out of service until an equivalvent boiler could be secured and installed, which could take several weeks. The project involves replacing the existing boiler with a new high-efficiency boiler.

There are currently issues with supply air to the existing conventional boiler in Aux 3. There is a large compressor in the boiler room and both the air compressor and the boiler receive their inlet air from the room, resulting in poor boiler combustion when the air compressor and boiler are both operating. The new proposed boiler will have a high-efficiency design and will receive its inlet air from outside ducting to address the current combustion issue.

Project Scope: The Dawn Aux 3 Boiler Replacement project includes design, procurement, installation and commissioning in 2020.

Expenditures: The total cost of the project is $313,600.

Resources: Internal resources will be used for this project.

Leave to Construct: Not Applicable.

Project: Transmission Compression - Engine Overhaul Program

Project Description: Four critical compressor stations are strategically located along the Dawn to Parkway Transmission System: Dawn, Lobo, Bright and Parkway. Discrete blocks of centrifugal compression are located at each of the stations and used in various combinations to manage the seasonal and weather-dependent system flow demand. There are nine centrifugal compressors at Dawn, five at Lobo, four at Bright and four at Parkway ranging in horsepower outputs, vintages, and models. Transmission compressors can pose a very large consequence of failure as they are integral assets required to achieve the Dawn to Parkway Transmission system deliverability requirements throughout the year. The consequence of compressor failure is dominated by gas cost impacts to customers. Transmission system risk associated with failure of a single compressor is heavily influenced by the time of year, weather severity, and time to mitigate the failure.

The compressor package is comprised of a gas turbine engine driver, compressor, power turbine and ancillary equipment such as lube oil, fuel supply, and electronic control systems, which are required for the compressor to operate. The gas turbine engine is very complex and carries the greatest failure risk of all of the compressor package components. By continuing to comply with original equipment manufacturer (OEM) recommended Preventive Maintenance (PM) schedules and overhauls, compressor reliability risks are controlled to moderate levels. In the case of performing regular OEM-prescribed overhauls, the risk of unit failure is proposed as a saw tooth function, whereby risk increases gradually over the 25,000 hour recommended interval between overhauls and then drops suddenly after an overhaul. Based on average annual use, overhauls for each engine are between 12 to 18 years and are staggered, nominally one per year.

Critical internal wear components are on a path to failure and generally in sync with operating hours. If the operating hours are extended too far, the resulting additional operational stress on internal components, such as high temperature coatings and bearings, will increase the component scrap rate when performing the overhaul. This will add significant (10 to 20 % or more) cost to the base overhaul and increases the risk of a random failure leading to system unreliability and further cost increases.

Scope
With the recent additions and retirements of compressors along the Dawn-Parkway system and operational changes required to support the various system demands, the usage profile associated with individual compressor units has shifted. Based on the hours accumulated over the past operating season, the Dawn J and Parkway B units will not exceed the overhaul hour threshold recommended by the OEM. Therefore, the Dawn J Plant Engine overhaul and Parkway B Plant Power Turbine/Compressor overhauls previously identified will not be required in 2020. Therefore, there are no planned overhauls for the transmission compressor fleet in 2020.

Expenditures
Engine overhauls range in cost from $1.0 to $4.0 million depending on the engine model, condition, and overhaul interval. The expected expenditure for this program is $25.5 million over the next ten years.

Resources
On-site work involving engine removal, reinstallation and commissioning, is carried out by the respective station mechanics and technicians. Time to complete the on-site work varies depending on compressor model and vintage. The removal and preparation for the shipping phase typically takes a week and the reinstallation and commissioning typically takes a week. On-site direction by an OEM field service representative may be requested in some of the more complicated installations.
Engine overhaul work is completed offsite at an OEM-approved shop.

Leave to Construct
Not applicable.

Project: Waubuno Compressor Replacement Project (AMP ID 1152)

The Waubuno Compressor elevates available pipeline pressure to the Waubuno Pool MOP. Compression increases the working inventory value of the pool by approximately $2.2 million (at $0.75 per GJ) based on top of what the pipeline alone can achieve. The compressor is operated approximately 45 days per year in late summer to early fall to top off the pool.

The consequence of compressor failure is dominated by customer impact. Risk associated with failure of the Waubuno Compressor is heavily influenced by the level of the pool at which the failure occurs and time to mitigate the failure. The Joy Compressor (manufactured in 1985) was a used compressor package purchased by Union and installed at Waubuno in 1988. The Joy Compressor Company changed ownership approximately 20 years ago whereupon original equipment manufacturer (OEM) support for the compressor was discontinued. Although normal wear components are still available in the marketplace, replacement major compressor items such as cylinders, crankshafts, and rods, etc., required to support a critical failure are no longer available. In the event of a critical failure, sourcing used parts (which are rare) or aftermarket custom machining services would be the only options for repair. This was the case in 2007 when a discharge valve seat failed, resulting in catastrophic damage to the cylinder 611. An extensive search across the used parts dealers was required to secure a viable used cylinder head. Other internal damage was repaired through custom machining services. In the event of a future failure, if useable parts or custom machining are not available, two available options would be custom-designed aftermarket castings (if possible) or replacement of the entire compressor. However, both options would render the compression out of service for at least one operational season.

Scope

This project involves replacement of the Waubuno Compressor to mitigate the risk of a critical part failure that would render the compressor out of service for an extended period of time. The proposed timing to complete the removal of the existing unit, installation, and commissioning of the new asset is 2022. The design and ordering of long-lead items is required to occur a year in advance.

The one-year delay of the Waubuno project is to allow for alignment with the alternative selected for compressor replacement at the Corunna Compressor facility. The design and ordering of long-lead items is planned for 2021.

Expenditures

Total capital expenditure for the replacement of the Waubuno Compressor is estimated at $21.0 million.

Resources

Core Projects will work with a third party engineering firm to complete the design and a contractor to complete the field work. Operations will support Core Projects as required.

Leave to Construct

A Leave to Construct is required. Timing will need to coincide with the 2021 start of the project.

Project: Belleville Category 3 Facility Project (AMP ID 1493, 1985)

Project Description: The Belleville Operations Centre is a 13,750-square-foot facility located at Enterprise Drive in Belleville, Ontario in a location that adequately services the Belleville market. The age of the building is not known as it is a leased facility. The facility itself does not satisfy the current operational standards nor does it meet current Ontario Building Code (OBC) requirements.
In 2016, an operational performance assessment was conducted by Union personnel which identified several deficiencies in the existing facility including but not limited to the inappropriate amount of space, inadequate storage, meeting space and site security, and legacy environmental concerns regarding water quality. The review also found the building to be deficient in several building code and life safety requirements.

Physical Obsolescence: The acceptable Union standard for physical condition is a Facility Condition Index (FCI) score of 0 per cent to 5 per cent. An FCI score is not available for this facility. However, the physical condition of the facility does not meet Union standards and is not considered correctable at this location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Building: The acceptable Union standard for functional condition is 0 per cent. Anything between 0 per cent and 50 per cent is considered correctable at the current location. An AI score is not available for this facility. Based on the review, the building does not meet the functional requirements of the business and the conditions are not considered correctable at the current location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Functional Obsolescence - Site: The site size is unknown. However, the site does not provide adequate traffic control, storage or security. These conditions are not considered correctable at the current location as it is leased space.

Meets Standards		Correctable at Current Location	
Positive	NEGATIVE	Positive	NEGATIVE

Furniture: Legacy furniture (20+ years old) does not meet Union's current condition standards. At this facility, 53 per cent of the furnishings are considered legacy and therefore not compliant with current standards. The building and site deficiencies are numerous, and considered not correctable at this location due to the fact that this is a leased property.

Expenditures: The total cost of the project is $7.5M, with $0.3M in 2020 and $7.2M in 2021.

Leave to Construct: N/A

Project: Bristol 3330 Replacement Program

Project Description

The legacy Union Gas SCADA system consists of approximately 300 stations that monitor and control the flow of natural gas within our transmission and distribution networks. The backbone of the system is the Bristol series 3330 RTU (Remote Terminal Unit), custody transfer measurement, compressor control, pressure/flow control, odourization, and area measurement functions. We currently have approximately 400 3330 series RTUs installed at our stations. The 3330 generation of technology became obsolete in 2009 and available repairs have ended in 2011. We can no longer purchase new 3330 series RTUs and replacement parts. Since that time we have installed ControlWave Micro at new sites. In mid-2012, we started upgrading and using replaced RTUs as spare parts for repairing the 3330 RTUs still in operation. As time proceeds, this will cause a reduction in our current service levels and increase our repair times surrounding RTU equipment.

The current RTU infrastructure is well maintained and in good condition. However, critical stations within the network that cannot remain using obsolete technology. A lengthened outage at one these stations would severely impact pipeline safety and operation.

The RTUs do not operate independently within the SCADA system. The system depends on the RTUs as well as the SCADA host and communication system to operate the pipeline. We recently invested $5,000,000 upgrading the SCADA communication system and $15,000,000 replacing the SCADA host. If we do not continue the mitigation program that was started in 2012, the RTUs will become the weak link within the SCADA system.

Project Scope

Between mid 2012 to end of 2019, we have upgraded 240 sites and in 2020 we expect to upgrade another 35 sites. The previous sites are the smaller and less complex stations. The remaining years of the upgrade project will involve upgrades at larger, more complex, and expensive sites. In 2020 through to 2024, all obsolete RTUs within legacy Union Gas will be replaced. As the project progresses, priority will be given to upgrading the critical stations and reclaiming existing equipment into the spare parts inventory.

Expenditures: The cost of the project for 2020 is $4.3 million.

Resources: All material and equipment are procured externally. Both internal and external resources will be used to complete different tasks under this project.

Leave to Construct: Not Applicable.

Project: Pipeline Integrity Management Programs (AMP ID 902, 175)

Project Description:
The Pipeline Integrity Management Program includes a systematic approach to assessing the condition, and completing the associated mitigation to ensure that they are suitable for continued service. The program manages the following:

- Pipelines for which the stress level is at or above 30 per cent of the Specified Minimum Yield Strength (SMYS) of the pipe at its MOP
- All National Energy Board (NEB) regulated pipelines (regardless of the stress level)

The formal program was initiated in 2002, and the baseline condition monitoring of the pipelines within the scope of the program that were installed prior to 2002 was completed by 2013, primarily through inline inspection (ILI) or External Corrosion Direct Assessment (ECDA). Work has been continuing to inspect the newer lines and to reinspect the previously inspected lines.

The Pipeline Integrity Management Program includes approximately 2,980 km of pipe that meet the specified criteria, inlcuding the pipe up to and including the station inlet valve. The piping between the station inlet and outlet valve is included within the Station Integrity Management Program. The rest of the pipeline system is included within the Distribution Pipeline Integrity Management Program.

The activities associated with this work include the following three components:

- **Launchers/Receivers in stations**: Install permanent ILI launcher and receiver facilities at selected Station sites where ILI runs have been identified. These programs are intended to carry on a prescribed inspection cycle and will require facilities to be available for future ILI activity.
- **Retrofitting pipeline to accommodate smart tools**: Modify pipelines to accommodate ILI tools, such as replacing reduced port valves, or bottom-out connections that prohibit the travel of ILI tools.
- **Integrity digs/mitigation**: ILI-identified defects are categorized as Immediate, Scheduled or Monitored based on Union's policy, which follows code, regulations and industry best practices.

The Distribution Pipeline Integrity Management Program includes a systematic approach to assessing the condition, and completing the associated mitigation, on pipelines for which the stress level is below 30 per cent of the SMYS of the pipe at MOP, to ensure that they are suitable for continued service. Much of this work is completed and budgeted through Distribution Operations. To supplement this work, a few targeted areas were identified within the centralized Distribution Pipeline Integrity Management Program to advance knowledge and manage risk associated with these assets.

The Distribution Pipeline Integrity Management Program includes approximately 67,440 km of mains and services within Union's pipeline system up to and including the station inlet valve that is not covered by the Pipeline Integrity Management Program. The piping between the station inlet and outlet valve is included within the Station Integrity Management Program.

Scope:
The scope of the key activities for the greater than 30 per cent SMYS pipelines includes those activities noted earlier in this section. For the Distribution Pipelines, activities to date within scope have included advancing the assessment of legacy down plant, cased piping, and vintage plastic pipe. In 2015, Union started to complete ECDA inspections and digs on the more critical distribution lines. More focused water crossing inspections were started in 2016 and the program was further developed in 2018 and will

continue for a number of years to advance the completeness of the inspection of pipelines that cross water bodies either under ground or attached to bridges.

Expenditures: The total cost of the program in 2020 is $25,626,000.

The total capital expenditure of the Integrity Management Program is $129.6 million from 2019 to 2028. The costs of the program were estimated using a combination of individual project estimates and historical unit costs and trends.

Resources: This program is managed with internal Engineering resources at Union and is typically executed by external contractor resources.

Leave to Construct: Typically, the majority of the pipeline segments requiring capital replacement do not meet the thresholds requiring an application for a Leave to Construct. However, as projects are scoped for individual segment remediation, the requirement for a Leave to Construct is evaluated on a case-by-case basis.

Project: Bruce Lake MOP upgrade

Project Description
This project has been proposed to overcome the capacity constraints that exist in the Bruce Lake (NPS 8) lateral, which is restricting the ability to deliver the contractual load to a customer by 2020. The required capacity can be obtained by upgrading the MOP of the system (Bruce Lake and Red Lake lateral) to 540psig. The 2020 work will involve any carryover from 2019 and site cleanups.

Project Scope

This project is expected to be completed in 2020. If the project is rejected, we will not be able to serve the contracted load to the customer, subjecting UG to financial liability.The following alternatives were considered:

1) Reinforcing system with an NPS 12 pipeline. The alternative was rejected due to a high capital cost.

2) Installing a compressor on Bruce Lake lateral, 24 km south of Ear falls. The alternative was rejected due to high capital cost and continuous operational cost.

The following are assumptions for the project:

- As per contract, Goldcorp could have ramped up in November 2017, but the expected increase in load has not yet occured. Sales continues to monitor Goldcorp for a likely in service date for their new equipment which could be in service in 2020.
- TSSA will provide endorsement for MOP upgrade.
- Onsite LNG will be available to mitigate pigging risks and to allow the hydrostatic test to be completed without customer interruption.
- Inline inspection was successfully completed in 2018-2019.
- Anomalies have been identified through in-line inspection (ILI) and due to the scope of anomalies found, a portion of the remediation work will now likely need to be carried over into 2020.
- Due to the scope of the anomalies found through ILI, the hydrostatic test of the line and any following MOP upgrade work will likely be delayed until 2020.
- Material/labor/permits/land will be available as per construction schedule.

Expenditures: The total cost of the project is $8,618,800.

Resources: Alliance Partner to compete construction work.

Leave to Construct: Not applicable.

Project: Class Location Program (AMP ID 173, 897)

Project Description
Changes in pipeline class location are assessed annually: the segments are added to the program and their remediation prioritized as they are assessed.

Segments within 2020 plan may include the following projects. Some projects need to be flexible between 2020 and 2021.

- Trafalgar 26 - Branchton
- Owen Sound Line NPS 10 - Elmira Pressure Test
- Trafalgar NPS 26 - Concession Road 8
- Marten River NPS 12 - Cedar Lake Lodge
- Oxford NPS 6 - Swimming Pool Road
- Trafalgar NPS 34 - Unnamed Road
- Picton Lateral - Johnson Street
- Augusta NPS 8
- Texasgulf Lateral
- Sudbury Section One - Michaud Road
- Sudbury Section One - Sturgeon River
- Kelly Lake Inco Line
- Marten River NPS 12 - Valve Cut in
- Trafalgar NPS 34 - Hamilton-Milton

If the program is deferred or rejected, we will be out of compliance and growing a backlog of remediations.

Project Scope: Changes in class location on pipeline systems as defined in *CSA Z662 – Oil and Gas Pipeline Systems*, are required to be assessed and remediated as necessary as mandated *by O. Reg. 210/01: Oil and Gas Pipeline Systems* under the *Technical Standards and Safety Act, 2000, S.O. 2000, C.16*. At Union, class location surveys are completed, and resulting class changes are evaluated and assessed for remediation by engineering staff on an annual basis. Pipeline segments that are deemed to have undergone a legitimate class change are evaluated based on the prescribed requirements in *CSA Z662*; and where deficiencies are identified, one of three forms of remediation are typically undertaken to maintain compliance to regulation.

- **Pressure Test Records** – Where pressure test records are inadequate for the new class location and the execution of a new pressure test is practical, affected pipeline segments are sometimes taken out of service to undergo an updated pressure test to meet the new class location requirements.

- **Valve Spacing** – Where the existing valve spacing may be inadequate based on the new class location requirements, an Engineering Assessment is completed to determine valve spacing adequacy. The result of the Engineering Assessment can be either that the valve spacing is determined to be adequate and no further remediation is required, or that the spacing is in fact inadequate and the addition of valves or pipe replacement is required.

- **Design/Location Factor** – Where the existing pipeline segment design is deemed to be inadequate for the new class location, the segment is scheduled for capital replacement and a new pipeline design is completed based on the new class location designation.

Other less common forms of remediation not identified above can also be required based on the class change assessments such as depth of cover remediation and/or repairs of pipeline defects deemed no longer acceptable for the new class location. Given that development is occurring in close proximity to Union's pipelines annually triggering class location changes, an annual budget is required in order to meet regulatory requirements. This work ensures we are compliant with the applicable codes and standards and contributes to our efforts to maintain public safety and operational safety of Union's pipeline system.

Completing Engineering Assessments were considered as an alternative but it was determined this method would not find these segments in compliance with the higher class location designation. In some cases, an Engineering Assessment was completed by a third party consultant and required remediation was confirmed.

Expenditures: The cost of the project in 2020 is $20,788,400. The total capital expenditure of the Class Location Program is $165.4 million from 2019 to 2028.

Resources: This program is managed with internal Engineering resources at Union and is typically executed by external contractor resources.

Leave to Construct: Typically, the majority of the pipeline segments requiring capital replacement do not meet the thresholds requiring an application for a Leave to Construct. However, as projects are scoped for individual segment remediation, the requirement for a Leave to Construct is evaluated on a case-by-case basis.

Project: Byron Transmission Station Rebuild Project (AMP ID 1518)

Project Description
The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.*

NOTE: *Only regular rate growth is available until 2022, assuming all previously identified contract customers bring on their requested loads. If contracts fall through or are decreased, capacity is freed up on the system.

Project Scope
The Byron Transmission Station Rebuild Project is a full rebuild currently scheduled to be completed in 2021.

- Purchase of land is in the plans for 2020 as additional land will be required.
- As part of the rebuild, the existing station will provide gas to the customers fed off of Byron Transmission Station, acting as temporary regulation.
- The regulations runs will be split so that the 6,160 kPa MOP feeds the 3,450 kPa MOP system and the 1,380 kPa MOP system will feed the 420 kPa MOP system.
- A new heating system (boiler system) will replace the existing inefficient and large volume glycol boilers. As a result of splitting the regulation runs, heating load requirements are reduced and efficiency of the system is increased.
- Monitor/operator regulation runs will replace the current design and position the station for future growth as existing regulators are at maximum capacity. This will also result in lower emissions (token relief versus existing full relief) and reduce noise (station situated in densely populated and growing neighbourhood).
- Existing orifice meters will be replaced by turbine meters to ensure accurate area measurement as well as measurement used for odourization purposes.
- The majority of station piping installed in 1968 will be removed and replaced with new pipe sized for future growth eliminating current velocity concerns.

All of the modifications to be completed as a result of this rebuild enhance station safety, reliability, and maintainability, positioning the area for growth out to 2044, assuming reinforcement is completed upstream and downstream as needed. There is potential for additional capacity with relatively minor station changes in 2044 and beyond.

Expenditures: Total capital expenditure is $349 thousand (2020) and $15.2 million (2021).

Resources: These larger full station rebuild projects are traditionally planned and designed by the Major Projects department. Planning has a team of dedicated full-time employees that will continue to manage and execute major projects such as the Byron Transmission Rebuild. The construction work will be managed by Major Projects and a contractor will execute the work. Depending on the scope, the construction contractor resourcing will be managed through a combination of existing Environmental Assessment (EA) contractors and bid process to source out additional contractor resources where required.

Leave to Construct: Not applicable.

Project: Kingsville Transmission Reinforcement Project (KTRP) (AMP ID 1550, 1494, 1551, 1552, 857)

Project Description
This project will deliver the installation of approximately 19km of NPS 20 from the existing NPS 20 Panhandle Line in the Town of Lakeshore to the Kingsville area. A new valve site will be installed at the tie-in to the Panhandle Line and new gate station at the south end to tie-in to the existing distribution system in Kingsville.

This project will support residential, commercial and industrial growth in Windsor-Essex, Chatham-Kent and surrounding areas, including greenhouse market in the Leamington and Kingsville area.

Project Scope:
This project consists of the installation of an approximately 19 km NPS 20 pipeline from an interconnect at the existing NPS 20 Panhandle Line in the Town of Lakeshore to a new station in the Town of Kingsville. Full details of the project are available in Union's pre-filed evidence for Ontario Energy Board Application EB-2018-0013.

Expenditures: The total cost of the project is $105.7 million. The cost for 2020 is $15.978 million.

Resources: This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

Leave to Construct: Union filed a Leave to Construct application with the Ontario Energy Board for this project *(EB-2018-0013)*. Approved in Decision September 20, 2018.

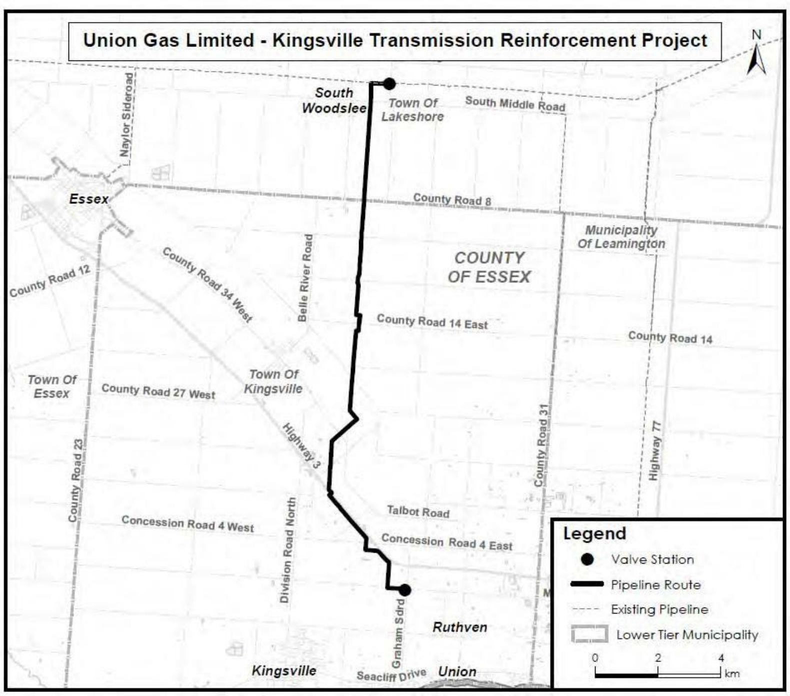


Figure 1: Proposed pipeline route

Project: Windsor Line Replacement Project (AMP ID 212, 913)

Project Description
The existing 65 km Windsor Line is a distribution line operating at 1,380 kPa that runs from Windsor to Port Alma. This line, the majority of which is NPS 10, primarily serves the residential, commercial and greenhouse markets of Tilbury, Essex, Lakeshore, Comber, Leamington and Windsor. The Windsor Line can also be operated as a back feed for the Sarnia South Line and the Ridgetown Line during emergencies. A significant portion of this line was installed in the 1930s, 1940s and 1950s and all joints prior to the 2000s were made with unrestrained mechanical couplings; portions of the older vintage pipe cannot be welded. In addition, some sections of the line cannot be isolated because of inoperable mainline valves. The Windsor Line also has sections that have poor depth of cover. Based on these integrity concerns and the significant effort and resources spent on repairing leaks on the line, the Windsor Line has been deemed a high risk and has therefore been identified as requiring replacement.

The Windsor Line will be replaced and the replacement pipeline will primarily be within road allowance with a shorter section possibly in easement. Both the services and stations will have to be upgraded for the new maximum operating pressure. This replacement will address the integrity and operational risks with the Windsor Line and will thereby mitigate future large customer outages in the event of emergencies and necessary leak repairs, ultimately improving the overall reliability of this pipeline. The replacement will also create incremental capacity for future growth in the area.

Project Scope: The project includes the replacement of the entire Windsor Line. The existing line is a combination of NPS 10 and NPS 8 and will be replaced by an NPS 6 pipeline. The existing line operates at a pressure of 1,380 kPa and the replacement will be designed to operate at a maximum operating pressure of 3,450 kPa. The intent is to replace the existing line using the road allowance as much as possible for the new NPS 6. Approximately 650 services and 20 stations are served by the existing line which will be upgraded to the new maximum operating pressure and served by the replacement NPS 6.

Project development has started with frontend engineering design beginning in the summer of 2018 with the environmental assessment planned for 2019 and construction in 2020.

Expenditure: The total cost of the project is $92,744,000.

Resources: Project management and construction management will be completed by Union's Major Projects Group. Engineering, environment, land, regulatory and procurement will be completed in-house at Union. Construction will be completed by a contractor selected using the approved Union procurement models.

Leave to Construct: The scope and approval of this project is regulated by the Ontario Energy Board. Union filed a Leave to Construct application *(EB-2019-0172)* with the Board in 2019 to seek approval to construct.

The existing 65 km Windsor Line is identified in red on the map shown below.

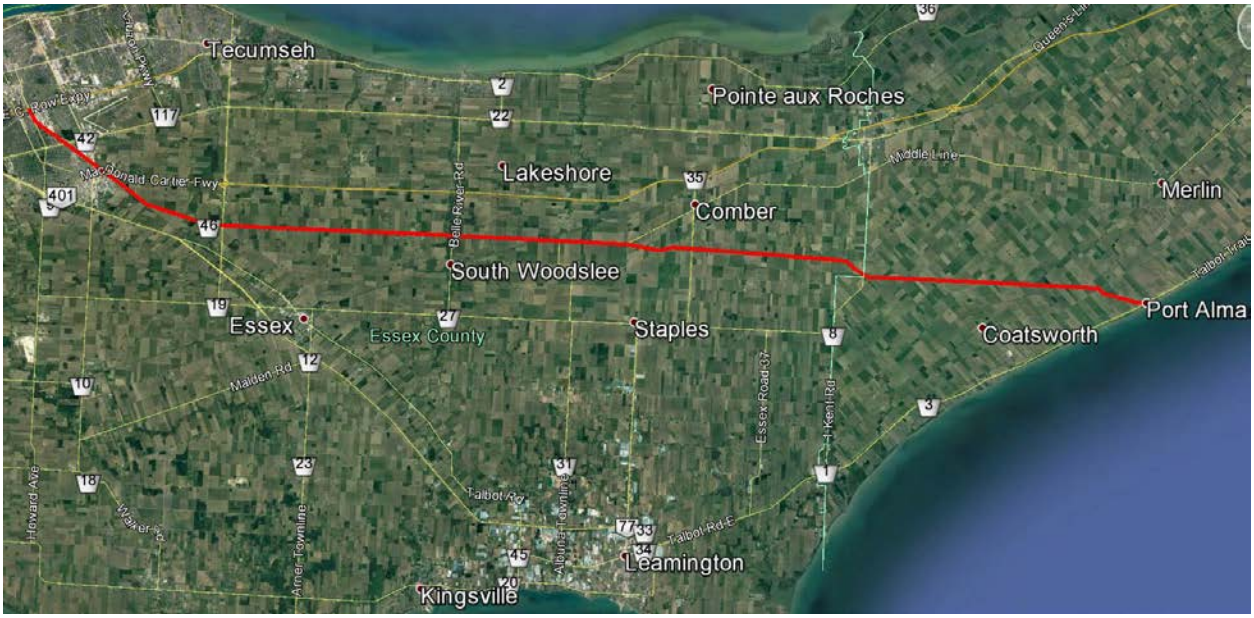


Figure 1: Existing Windsor Line

Project: 2021 Sarnia Industrial Line System Expansion Project

Project Description: The Sarnia Industrial Line system is comprised of a series of parallel pipelines: NPS 10, NPS 12, NPS 16, and NPS 20. The system starts at the Vector Courtright and Great Lakes Courtright stations in St. Clair Township and extends to the Churchill Road Station in Sarnia. The system is also connected to the Dawn Compressor Station.

NPS 12 pipe runs the entire distance between the Courtright stations and the Sarnia Industrial Station. NPS 20 pipe runs the majority of the way from the Courtright stations to the Dow Valve Site. NPS 16 pipe runs between the Novacor Corunna station and the Dow Valve Site. NPS 10 pipe runs between the Dow Valve Site and the Churchill Road Station.

The Sarnia Industrial Line system is also connected to Dawn from the NPS 20 Payne to Sarnia pipeline between Payne Pool station and the Novacor Corunna station, and through the NPS 8 Dawn Kimball and NPS 10 Payne Kimball pipelines. The Sarnia Industrial Line system was last expanded in 2015 under filing EB-2014-0333, the Sarnia Expansion Pipeline Project.

Scope: Union has identified the need for system reinforcement to serve forecasted industrial contract rate growth in the Sarnia market. This project consists of the system reinforcement from the Dow Valve Site to the Bluewater Valve Site (1.2 km of NPS 20) , plus a customer station. The project will consist of planning and engineering to commence in 2019, with construction to begin in 2021.

Expenditures: The total expenditure for this project is approximately $29 million from 2019 to 2022.

Year	Expenditure ($)
2019	508,000
2020	1,034,000
2021	26,450,000
2022	1,076,000
Total	29,068,000

Resources: This project will be planned and designed by resources in the Major Projects department. The construction work will be managed by the Major Projects department with a third party contractor executing the work. Construction contractor resourcing will be managed through a bid process.

Leave to Construct: This project will require a Leave to Construct application to be filed with the Ontario Energy Board, targeting Q4 2019.