Rakesh Torul
Technical Manager
Regulatory Applications
Regulatory Affairs

tel 416-495-5499
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

VIA RESS and EMAIL

October 15, 2021

Christine Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Christine Long:

Re: Enbridge Gas Inc. ("Enbridge Gas" or "EGI")
Ontario Energy Board ("OEB") File No. EB-2021-0148
2022 Rates (Phase 2) Application and Evidence (Incremental Capital Module)

Please find attached an Application by Enbridge Gas Inc. ("Enbridge Gas" or "EGI") for interim and final orders of the Ontario Energy Board ("OEB") under section 36 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of natural gas, commencing January 1, 2022. Specifically, as set out in this Application, Enbridge Gas applies for approval of unit rates related to its 2022 Incremental Capital Module ("ICM") requests.

Background

On August 30, 2018, in the MAADs Decision (EB-2017-0306/0307), the OEB approved a rate setting mechanism (Price Cap IR) for Enbridge Gas, which sets out a multi-year incentive rate-setting mechanism ("IRM") for the calendar year term of 2019 to 2023 (the "five year term" or the "deferred rebasing period"). The MAADs Decision confirmed that during the five-year term, distribution rates will be set separately for the Enbridge Gas Distribution ("EGD") and Union Gas ("Union") rate zones. The MAADs Decision also approved the specific treatment of various elements in the IRM including the availability of an Incremental Capital Module ("ICM") during the five-year term.

This 2022 Rate Application is the fourth annual rate adjustment application under the IRM approved in the MAADs Decision.

On June 30, 2021, Enbridge Gas filed supporting evidence in EB-2021-0147 in relation to the 2022 Rate Application, which includes the annual rate escalation, pass-through costs, capital pass-through adjustments and Parkway Delivery Obligation rate adjustments, referred to as Phase 1. A Settlement Proposal, including a resolution of all items in the Phase 1 Rate Application, was filed on September 29, 2021.

In the cover letter related to Phase 1, Enbridge Gas advised that evidence related to the request for ICM funding will be filed as Phase 2 of the 2022 Rate Application.

This Application (EB-2021-0148) is for Phase 2 of the 2022 Rate Application and addresses matters related to 2022 ICM funding request. With this Application, Enbridge Gas is seeking OEB approval for ICM funding for five projects in 2022 – the St. Laurent Ottawa North Replacement (Phase 3) Project and NPS 20 Replacement Cherry to Bathurst Project in the EGD rate zone, and the Dawn to Cuthbert Replacement and Retrofits Project, Byron Transmission Station Project and Kirkland Lake Lateral Replacement Project in Union rate zones. The ICM evidence including the appendices are filed as Exhibit B, Tab 2, Schedule 1.

Also, in accordance with the commitment made in the 2020 Rates Application (EB-2019-0194), Enbridge Gas is filing a Progress Report on Implementation of ScottMadden Recommendations on Unaccounted for Gas (UFG). This report is filed as Exhibit C, Tab 2, Schedule 1.

To support the ICM projects in this Application, Enbridge Gas is filing an addendum to the Asset Management Plan 2021-2025 (2020 AMP). The 2020 AMP was filed in the 2021 Rate application in EB-2020-0181. The addendum to the Asset Management Plan is filed as Exhibit B, Tab 2, Schedule 3.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Rakesh Torul
Technical Manager,
Regulatory Applications

cc: David Stevens, Aird and Berlis LLP
EB-2021-0148 Intervenors

EXHIBIT LIST

Exhibit	Tab	Schedule	Appendices	Attachments	Contents
A					ADMINISTRATION
	1	1			Exhibit List
	2	1			Application
B	1	1			RATE SETTING MECHANISM (Filed in Phase 1 under EB-2021-0147)
B	1	2			ASSESSMENT OF ALTERNATIVES TO ELIMINATE OR REDUCE PDO AND/OR PDCI (Filed in Phase 1 under EB-2021-0147)
B	2	1			INCREMENTAL CAPITAL MODULE
				Attachment 1	2022 Capital Budget and ICM Funding Calculation based on previously OEB-Approved Overheads Capitalization Policy
			Appendix A		Historical and Forecast Capital Expenditures
			Appendix B		Calculation of Revenue for ICM Threshold Calculation
			Appendix C		Means Test
			Appendix D		N/A - Intentionally Left Blank
			Appendix E		2022-2023 ICM Project Revenue Requirement
			Appendix F		Allocation of 2022 ICM Project Revenue Requirement
			Appendix G		Derivation of 2022 ICM Rates by Rate Class
			Appendix H		Calculation of 2022 ICM Bill Impacts - EGD Rate Zone
			Appendix I		Calculation of 2022 ICM Bill Impacts - Union Rate Zones
B	2	2			BUSINESS CASES
			Appendix A		Business Case: Dawn-Cuthbert Replacement and Retrofits
			Appendix B		Business Case: Byron Transmission Station
			Appendix C		Business Case: Kirkland Lake Lateral Replacement
B	2	3			ADDENDUM TO ASSET MANAGEMENT PLAN
C	2	1			PROGRESS REPORT ON IMPLEMENTATION OF THE RECOMMENDATIONS AS SET OUT IN THE UFG REPORT
D					DRAFT RATE ORDER
	1				Draft Rate Order - EGD Rate Zone (Filed in Phase 1 under EB-2021-0147)
	2				Draft Rate Order - Union Rate Zones (Filed in Phase 1 under EB-2021-0147)

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an Application by Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2022.

APPLICATION

1. The Applicant, Enbridge Gas Inc. ("Enbridge Gas", or "EGI") is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting, and storing natural gas within Ontario. Enbridge Gas was formed effective January 1, 2019, upon the amalgamation of Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union").

2. Enbridge Gas hereby applies to the Ontario Energy Board (the "OEB"), pursuant to section 36 of the *Ontario Energy Board Act, 1998*, as amended (the "Act") for interim and final Orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2022. Specifically, as set out herein, Enbridge Gas applies for approval of unit rates related to its 2022 Incremental Capital Module ("ICM") requests.

3. On August 30, 2018, in the MAADs Decision[1], the OEB approved a rate setting mechanism (Price Cap IR) for Enbridge Gas, which sets out a multi-year incentive rate-setting mechanism ("IRM") for the calendar year term of 2019 to 2023 (the "five

year term" or the "deferred rebasing period"). The MAADs Decision confirmed that during the five year term, distribution rates will be set separately for the EGD and Union rate zones. The MAADs Decision also approved the specific treatment of various elements in the IRM including the availability of an ICM during the five year term.

4. The 2022 Rate Application is the fourth annual rate adjustment application under the IRM approved in the MAADs Decision.

5. Similar to the approach directed by the OEB for the 2021 Rate application[2], Enbridge Gas is filing each Phase ("Phase 1" and "Phase 2") of the 2022 Rate application as a separate application.

6. On June 30, 2021, Enbridge Gas filed supporting evidence for "Phase 1" of its 2022 Rate Application (EB-2021-0147) to address the IRM related elements which included the annual rate escalation, pass-through costs, capital pass-through adjustment, Parkway Delivery Obligation rate adjustment and the assessment of alternatives to eliminate or reduce PDO and/or PDCI. On September 29, 2021, Enbridge Gas and all interested parties filed a Settlement Proposal that resolved all matters in "Phase 1" of the 2022 Rate Application, and includes draft Interim Rate Orders for updated 2022 rates to be effective January 1, 2022.

7. This Application (EB-2021-0148) is for Phase 2 of the 2022 Rate Application and addresses matters related to 2022 ICM funding request. With this application, Enbridge Gas is seeking OEB approval for ICM funding for five projects in 2022 – the St Laurent Ottawa North Replacement (Phase 3) and NPS 20 Replacement Cherry to Bathurst in the EGD rate zone, and the Dawn to Cuthbert Replacement and Retrofits, the Byron Transmission Station and the Kirkland Lake Lateral

---

[1] EB-2017-0306/0307.
[2] EB-2020-0095, OEB letter, dated July 14, 2020.

Replacement Projects in the Union rate zones. Collectively, these projects are referred to as the "2022 ICM Projects".

8. The ICM evidence including the appendices are filed as Exhibit B, Tab 2, Schedule 1.[3]

9. The St Laurent Ottawa North Replacement (Phase 3)[4] and the NPS 20 Replacement Cherry to Bathurst[5] projects in the EGD rate zone are subject to Leave to Construct applications where the need for the projects is being addressed.

10. The Dawn to Cuthbert Replacement and Retrofits, the Byron Transmission Station and the Kirkland Lake Lateral Replacement projects in the Union Rate Zones do not require Leave to Construct approval. To support the need for these projects, Enbridge Gas is providing the business case and Leave to Construct like evidence for each of the projects. The business cases are filed as appendices to Exhibit B, Tab 2, Schedule 2.

11. To support the 2022 ICM funding request[6], Enbridge Gas is also filing an addendum to the Asset Management Plan 2021-2025[7] for the ICM projects with this Application. The addendum to the Asset Management is filed as Exhibit C, Tab 1, Schedule 1.

12. Also, as per a commitment in the 2020 Phase 2 Rate Application[8], Enbridge Gas is filing a Progress Report on Implementation of ScottMadden Recommendations on

---

[3] In order to maintain consistency with prior applications related to ICM requests during the five year term, Enbridge Gas has labeled the ICM request evidence as Exhibit B-2-1 (meaning that there are no B-1-1 exhibits in this filing).
[4] EB-2020-0293
[5] EB-2020-0136
[6] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.32-34.
[7] In Phase 2 of the 2021 Rate application, Enbridge Gas filed an Asset Management Plan (AMP) for the period 2021-2025 at Exhibit C, Tab 2, Schedule 1.
[8] EB-2019-0194, Reply Argument of Enbridge Gas dated May 1, 2020, page 33; EB-2019-0194, Decision and Order dated May 14, 2020, page 20.

Unaccounted For Gas (UFG). This report is filed as Exhibit C, Tab 2, Schedule 1. Enbridge Gas is not seeking any OEB relief in relation to this report.

APPROVAL REQUESTS

13. The specific approvals sought in this Application are as follows:

    - The requests for ICM funding for the 2022 ICM Projects, including the ICM unit rates beginning in 2022 for the duration of the deferred rebasing period to recover the total revenue requirement of the 2022 ICM Projects from 2022 to 2023;
    - Final rates for the year commencing January 1, 2022, including the full-year impact of all items included in the "Phase 1" of the 2022 Rate Application in EB-2021-0147 and the ICM requests in this Application; and
    - The determination of all other issues that bear upon the OEB's approval or fixing of just and reasonable rates for the sale, distribution, transmission, and storage of gas by Enbridge Gas for the year commencing January 1, 2022.

14. Enbridge Gas further applies to the OEB pursuant to the provisions of the Act and the OEB's Rules of Practice and Procedure for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

15. This Application is supported by written evidence and may be amended from time to time as circumstances require.

16. The persons affected by this Application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores natural gas.

17. Approval of the 2022 ICM funding set out in this Application will result in the following bill impacts:

- The bill impact associated with the 2022 ICM funding request for a typical Rate 1 residential customer consuming 2,400 m^3 annually in the EGD rate zone is an increase of $1.11.
- The bill impact associated with the 2022 ICM funding request for a typical Rate M1 residential customer consuming 2,200 m^3 annually in the Union South rate zone is a decrease of $0.06.
- The bill impact associated with the 2022 ICM funding request for a typical Rate 01 residential customer in the Union North rate zone consuming 2,200 m^3 annually in the Union North rate zone is an increase of $0.55.

18. Enbridge Gas requests that all documents in relation to the Application and its supporting evidence, including the responsive comments of any interested party, be served on Enbridge Gas and its counsel as follows:

(a) The Applicant:	Regulatory Affairs Enbridge Gas Inc.
Address for personal service:	500 Consumers Road Toronto, ON M2J 1P8
Mailing Address:	P. O. Box 650 Scarborough, ON M1K 5E3
Telephone:	(416) 495-5499
Fax:	(416) 495-6072
E-Mail:	EGIRegulatoryProceedings@enbridge.com

(b) The Applicant's counsel: David Stevens
Aird & Berlis LLP

Address for personal service and mailing address: Suite 1800, Box 754
Brookfield Place, 181 Bay Street
Toronto, Ontario
M5J 2T9

Telephone: (416) 865-7783
Fax: (416) 865-1515
E-Mail: dstevens@airdberlis.com

DATED: October 15, 2021, at Toronto, Ontario

ENBRIDGE GAS INC.

(Original Signed)

____

Rakesh Torul
Technical Manager,
Regulatory Applications

ENBRIDGE GAS INC. 2022 RATE APPLICATION
INCREMENTAL CAPITAL MODULE

1. This evidence supports Enbridge Gas's request for incremental capital module ("ICM") funding for capital investments that are not funded through existing rates. The OEB approved the use of an ICM to fund incremental capital during Enbridge Gas's 2019-2023 deferred rebasing period as part of the MAADs Decision.[1] Enbridge Gas received approval for ICM funding from the OEB in 2019, 2020 and 2021. The OEB approved the Kingsville Reinforcement Project and Stratford Reinforcement Project as part of the 2019 Rates Decision[2], the Don River Replacement Project and the Windsor Line Project as part of the 2020 Rates Decision[3], and the London Lines Project as part of the 2021 Rates Decision[4]. In this application, Enbridge Gas is seeking ICM funding for five projects in 2022 – the St. Laurent Ottawa North Replacement Phase 3 Project and NPS 20 Replacement Cherry to Bathhurst Project in the EGD rate zone, the Dawn to Cuthbert Replacement and Retrofits Project and Byron Transmission Station Project in the Union South rate zone and the Kirkland Lake Lateral Replacement Project in the Union North rate zone.

2. The capital budget and the ICM request and funding calculations are based on the new harmonized overhead capitalization policy. As directed by the OEB in the 2021 Rates proceeding (EB-2020-0181)[5], Enbridge Gas is also including the capital budget and the ICM funding calculations based on the previously OEB-approved overhead capitalization policy as Attachment 1 to this Exhibit.

---

[1] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018. The Decision and Order was later amended by the OEB on September 17, 2018 with no material changes.
[2] EB-2018-0305, Decision and Order, September 12, 2019.
[3] EB-2019-0194, Decision and Order, May 14, 2020.
[4] EB-2020-0181, Decision and Order, May 6, 2021.
[5] EB-2020-0181, Decision and Order, May 6, 2021, p.20.

3. This evidence is organized as follows:

1. CAPITAL PLANNING

1.1 OVERVIEW

4. Enbridge Gas filed a consolidated Utility System Plan ("USP")[6] which included an Asset Management Plan 2021-2025 ("2020 AMP") for Enbridge Gas as part of its 2021 Rates Application (EB-2020-0181) in support of its ICM requests. In the 2021 Rates Decision, the OEB found the USP and AMP provided sufficient information for the OEB to assess the 2021 ICM funding requests.[7]

---

[6] EB-2020-0181, Exhibit C, Tab 1, Schedule 1 and Exhibit C, Tab 2, Schedule 1, Filed: 2020-10-15.
[7] EB-2020-0181, Decision and Order, May 6, 2021, p. 6.

5. In support of the 2022 ICM request, Enbridge Gas is filing an Asset Management Plan (“AMP”) Addendum[8]. The Addendum provides an update for budget year 2022 for the 2020 AMP filed as part of the 2021 Rates Application. The Addendum is not a stand alone document and should be reviewed in conjunction with the 2020 AMP. The principles outlined in the 2020 AMP have not changed and the identified asset life cycle strategies have no material changes. The asset needs do evolve over time and, where this has affected the 2022 budget, it has been noted in the variance explanations in the AMP Addendum. The AMP identifies how Enbridge Gas plans, manages and develops the distribution, transmission, and storage systems, and determines the capital investment requirement while balancing risk, performance and cost. 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. Through the budgeting process, the risks that each project is mitigating are re-evaluated and endorsed.

6. As there are finite resources to complete capital projects, projects are selected for the AMP on the basis of their relative priority. Using the 2020 AMP as a basis, emerging issues are evaluated and prioritized to ensure that capital resources are employed to address the highest priority items across all asset categories.

7. Enbridge Gas’s methodology for project prioritization considers risk, customer input and preferences, resource availability and asset portfolio strategies. More details on the project prioritization can be found in Enbridge Gas’s 2020 AMP.

---

[8] Exhibit B, Tab 2, Schedule 3.

1.2 HISTORICAL AND FORECAST CAPITAL INVESTMENTS

8. The historical and forecast capital investments by category for the 2017 to 2026 period are shown in Table 1 for the EGD rate zone and Table 2 for the Union rate zones. These capital investments will allow Enbridge Gas to continue to meet customer needs and ensure safe and reliable delivery of natural gas to customers.

Table 1
Capital Expenditures[9] by category (2017-2026)
EGD Rate Zone ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast
		(a)	(b)	(c)	(d)	(e)
1	General Plant	48.1	47.3	70.4	51.3	80.2
2	System Access[10]	109.3	108.9	151.1	70.5	192.8
3	System Renewal	102.2	92.3	110.4	233.6	223.0
4	System Service	20.2	22.9	23.9	20.8	34.5
5	Total Overhead[11]	148.1	140.2	151.6	149.1	-
6	**Total - EGD Rate Zone**	**427.8**	**411.6**	**507.4**	**525.2**	**530.5**

Line No.	Category	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
		(f)	(g)	(h)	(i)	(j)
1	General Plant	81.0	141.7	92.1	99.0	125.5
2	System Access[10]	151.9	169.5	201.0	168.1	173.6
3	System Renewal	465.3	460.5	313.6	288.3	342.0
4	System Service	36.1	42.0	68.5	107.4	45.4
5	Total Overhead[11]	-	-	-	-	-
6	**Total - EGD Rate Zone**	**734.3**	**813.7**	**675.2**	**662.8**	**686.6**

[9] Capital expenditure shown for 2017-2018, In-Service for 2019-2026.
[10] System access capital does not include Community Expansion and Compressed Natural Gas.
[11] Overheads included with projects costs for 2021-2026.

Table 2
Capital Expenditures[12] by category (2017-2026)
Union Rate Zones ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast
		(a)	(b)	(c)	(d)	(e)
1	General Plant	42.8	48.0	51.8	34.2	64.4
2	System Access[13]	96.2	83.5	104.4	85.5	119.5
3	System Renewal	94.1	99.4	106.4	141.6	306.3
4	System Service	405.8	201.2	162.1	117.0	145.4
5	Total Overhead[14]	78.6	81.0	83.1	73.8	-
6	**Total - Union Rate Zones**	**717.5**	**513.1**	**507.8**	**452.1**	**635.6**

Line No.	Category	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
		(f)	(g)	(h)	(i)	(j)
1	General Plant	70.1	84.0	49.8	56.9	56.1
2	System Access[13]	120.6	213.2	126.5	123.0	128.3
3	System Renewal	200.6	169.9	303.9	451.2	361.6
4	System Service	151.8	245.9	155.5	372.8	252.4
5	Total Overhead[14]	-	-	-	-	-
6	**Total - Union Rate Zones**	**543.1**	**713.0**	**635.7**	**1,003.8**	**798.3**

[12] Capital expenditure shown for 2017-2018, In-Service for 2019-2026.
[13] System access capital does not include Community Expansion and Compressed Natural Gas.
[14] Overheads included with projects costs for 2021-2026.

General Plant

9. General plant investments are modifications, replacements or additions to Enbridge Gas's assets that are not part of its commodity-carrying system including land and buildings, tools and equipment, fleet vehicles and electronic devices and software used to support day to day business and operations activities.

10. The historical and forecast general plant capital expenditures are presented in Appendix A in this exhibit, Table A for EGD rate zone and Table B for Union rate zones.

System Access

11. System access investments are additions and modifications (including asset relocation) to the Enbridge Gas distribution system that the utility is obligated to perform in order to provide a customer or group of customers with access to natural gas services via the distribution and transmission systems. System Access capital expenditures are driven mainly by Customer Growth, Natural Gas Vehicles (NGV) and third party driven rebillable relocation projects.

12. The historical and forecast system access capital expenditures are presented in Appendix A in this exhibit, Table C for EGD rate zone and Table D for Union rate zones.

System Renewal

13. System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of Enbridge Gas's system to provide customers with natural gas services. System Renewal capital expenditures are mainly driven by Main Replacements, Meter

Exchanges/Replacements, Compressor Equipment, Regulator Refits and Service Relays.

14. The historical and forecast system renewal capital expenditures are presented in Appendix A in this exhibit, Table E for EGD rate zone and Table F for Union rate zones.

System Service

15. System service investments are modifications to Enbridge Gas's distribution system to ensure the system continues to meet distributor operational objectives. System service capital expenditures are mainly driven by transmission and distribution system growth, reinforcement projects and integrity initiatives.

16. The historical and forecast system service capital expenditures are presented in Appendix A in this exhibit, Table G for EGD rate zone and Table H for Union rate zones.

1.3 2022 CAPITAL EXPENDITURE VARIANCE (PROPOSED 2022 BUDGET VS 2022 BUDGET AS PER 2020 AMP)

17. The 2022 Capital Expenditure variances between the proposed 2022 budget in this application versus the 2022 budget as per 2020 AMP by category are shown in Table 3 for the EGD rate zone and Table 4 for the Union rate zones. The tables and variances reflect in-service capital expenditures[15].

[15] Note that the capital expenditure set out in the AMP are presented on an as-spent basis, not an in-service basis, and adjustments to convert the AMP amounts to an in-service basis have been made for the purposes of this evidence.

Table 3
2022 Capital Expenditure Variance (Proposed Budget vs Budget as per 2020 AMP)
EGD Rate Zone ($ millions)

Line No.	Category	2022 Proposed Budget	2022 Budget as per 2020 AMP[16]	Variance
		(a)	(b)	(c) = (a-b)
1	General Plant	81.0	60.7	20.3
2	System Access	151.9	164.6	(12.7)
3	System Renewal	465.3	403.7	61.6
4	System Service	36.1	32.2	3.9
5	**Total - EGD Rate Zone**	**734.3**	**661.2**	**73.1**

Table 4
2022 Capital Expenditure Variance (Proposed Budget vs Budget as per 2020 AMP)
Union Rate Zones ($ millions)

Line No.	Category	2022 Proposed Budget	2022 Budget as per 2020 AMP[17]	Variance
		(a)	(b)	(c)
1	General Plant	70.1	56.8	13.3
2	System Access	120.6	328.5	(207.9)
3	System Renewal	200.6	197.6	3.0
4	System Service	151.8	123.0	28.8
5	**Total - Union Rate Zones**	**543.1**	**705.9**	**(162.8)**

[16] EB-2020-0181, Exhibit B, Tab 2, Schedule 1, Table 1, Filed: 2020-10-15.
[17] EB-2020-0181, Exhibit B, Tab 2, Schedule 1, Table 2, Filed: 2020-10-15.

Variance Explanations

18. Below are the 2022 Proposed Budget vs 2022 Budget as per 2020 AMP variance explanations by rate zone:

EGD Rate Zone

Line No.		Variance	Explanations
1	General Plant	20.3	**REWS** - Station B land purchase $10M, variances due to market availability and project scope variation to meet business facility requirements $8M **Fleet** – ProStopp T.D. Williamson isolation tool for double block and bleed isolation $6M **TIS** - Variance reflects evolving business needs including Green Button Initiative (Ministry of Energy), transition to cloud services and deferral of eGIS upgrade ($4M)
2	System Access	(12.7)	**DP - Relocations** - Decrease due to additional information available on relocations, adjustments to regional forecasts and NPS 20 Don River Waterfront Relocation Project rescoped and rescheduled ($18M) Growth - New mCHP (micro combined heat and power) carbon reduction initiative at TOC $5M
3	System Renewal	61.6	**DP Main Replacement** – St. Laurent construction deferral and re-phasing of segments $40M and variance to replacement program due to project pacing and updates to scope and costing $15M **Distribution Stations** – variances to the stations portfolio due to refined project costing and timing $17M **DP - Service Relay** - Decrease in Service Relay program (including AMP fittings) ($7M) Utilization – decrease in Meter purchases due to extended seal life on existing meters and reduced customer connections forecast ($4M)
4	System Service	3.9	**DP/TPS – Integrity** - increase to Integrity program due to updated scope and costing $9M **Utilization** – New AMI Pilot Project to support carbon reduction initiatives $3M **Growth** - Project deferrals as a result of lower growth forecast ($8M)
5	**Total - EGD Rate Zone**	**73.1**	

Union Rate Zones

Line No.		Variance	Explanations
1	General Plant	13.3	**REWS** - Change variances due to market availability and project scope variation to meet business facility requirements $13M **Fleet** – Increase in vehicle purchases due to vehicle assignment policy. Vehicle assignment is based on number of kilometers driven by employee in identified role and type of field work requiring a vehicle $3M **TPS Land** - Increase in strategic land purchases to manage land use adjacent to facilities based on market availability $4M **TIS** - Variance reflects evolving business needs including reductions to the Next Generation Contact Centre, Operating Technologies Lifecycle project, and Customer Data Analytics Solutions due to changing business requirements/timing ($6M)
2	System Access	(207.9)	**TPS Growth** - Dawn Parkway Expansion (Kirkwall to Hamilton NPS 48) in service date deferred ($216M) **Growth** - Increase in the greenhouse market growth and to overall connection costs $11M **Distribution Stations** – Advancement of CNG projects $2M Utilization – Change in assumption for Growth meter purchases ($5M)
3	System Renewal	3.0	**CS –** Increase to replacement program $4M **Distribution Stations** – Inside regulator and ERR program and various changes to project scope and timing $7M **Utilization** - Increase in regulator refit program due to increased labour costs for meter exchanges and exchanges deferred from 2021 to 2022 $9M **TPS Replacements** – reclass to System Service ($13M) **DP Corrsion -** NPS 20 shorted casing on Hwy 5 phase 2 deferred to 2023 ($3M)
4	System Service	28.8	**DP/TPS Replacements** - reclassed from System Renewal $13M and variance in replacement and class location programs due to pacing and scope $5M **Growth** – Byron Transmission Station project delayed to 2022 in-service $20M offset by change in reinforcement timing and scope due to changes in the growth forecast ($10M)
5	**Total - Union Rate Zones**	**(162.8)**	

1.4 2022 CAPITAL EXPENDITURE VARIANCE (PROPOSED 2022 BUDGET VS 2021 BUDGET)

19. The 2022 Capital Expenditure variance between the proposed 2022 budget in this application versus the 2021 budget as per 2020 AMP by category are shown in Table 5 for the EGD rate zone and Table 6 for the Union rate zones. The tables and variances reflect in-service capital expenditures.

Table 5
2022 Capital Expenditure Variance
(2022 Proposed Budget vs 2021 Budget as per 2020 AMP)
EGD Rate Zone ($ millions)

Line No.	Category	2022 Proposed Budget	2021 Budget as per 2020 AMP[18]	Variance
		(a)	(b)	(c) = (a-b)
1	General Plant	81.0	102.4	(21.4)
2	System Access	151.9	167.6	(15.7)
3	System Renewal	465.3	246.8	218.5
4	System Service	36.1	50.5	(14.4)
5	**Total - EGD Rate Zone**	**734.3**	**567.3**	**167.0**

[18] EB-2020-0181, Exhibit B, Tab 2, Schedule 1, Table 1, Filed: 2020-10-15.

Table 6
2022 Capital Expenditure Variance
(2022 Proposed Budget vs 2021 Budget as per 2020 AMP)
Union Rate Zones ($ millions)

Line No.	Category	2022 Proposed Budget	2021 Budget as per 2020 AMP[19]	Variance
		(a)	(b)	(c) = (a-b)
1	General Plant	70.1	55.6	14.5
2	System Access	120.6	150.7	(30.1)
3	System Renewal	200.6	327.6	(127.0)
4	System Service	151.8	93.1	58.7
5	**Total - Union Rate Zones**	**543.1**	**627.0**	**(83.9)**

Variance Explanations

20. Below are the 2022 Proposed Budget vs 2021 Budget as per 2020 AMP variance explanations by rate zone:

[19] EB-2020-0181, Exhibit B, Tab 2, Schedule 1, Table 2, Filed: 2020-10-15.

EGD Rate Zone

Line No.		Variance	Explanations
1	General Plant	(21.4)	**REWS** - Station B building deferral ($21M) and change variances due to market availability and project scope variation to meet business facility requirements ($13M) **Fleet** – ProStopp T.D. Williamson isolation tool for double block and bleed isolation $6M **TIS** - Variance due to changing business requirements year over year, project timing and transition to cloud services $6M
2	System Access	(15.7)	**DP - Relocations** - Variance in relocation projects based on adjustments to regional forecasts as scope was defined and the NPS 20 Don River Waterfront Relocation Project rescoped and rescheduled ($12M) **Growth** – Reduction in customer connections due to decreased customer growth forecast ($4M)
3	System Renewal	218.5	**DP Main Replacement** – St. Laurent Phase 3 $86M and NPS 20 Cherry to Bathurst $126M **Distribution Stations** – variances to the stations portfolio due to refined project costing and timing $14M **DP - Service Relay** - Service relay volumes decreased due to COVID-19 work restrictions ($6M) **Utilization** – decrease in Meter purchases due to extended seal life on existing meters and reduced customer connections forecast ($5M)
4	System Service	(14.4)	**Utilization** – New AMI Pilot Project to support carbon reduction initiatives $3M **Growth** - Project deferrals as a result of lower growth forecast ($16M)
5	**Total - EGD Rate Zone**	**167.0**	

Union Rate Zones

Line No.		**Variance**	**Explanations**
1	General Plant	14.5	**REWS** - Change variances due to market availability and project scope variation to meet business facility requirements $7M **Fleet** – Increase in vehicle purchases due to vehicle assignment policy. Vehicle assignment is based on number of kilometers driven by employee in identified role and type of field work requiring a vehicle $3M **TPS Land** - Increase in strategic land purchases to manage land use adjacent to facilities based on market availability $4M
2	System Access	(30.1)	**TPS Growth** – Sarnia Reinforcement project in-service 2021 (32M) **DP Relocations** – decrease in relocation projects based on adjustments to regional forecast as scope was defined ($5M) **Growth** - Increase in the greenhouse market growth and to overall connection costs $4M **Distribution Stations** – Advancement of CNG projects $3M
3	System Renewal	(127.0)	**CS –** Increase to replacement and overhaul program $10M **DP Main Replacement** – London Lines and Windsor Line Replacement projects in-service in 2021 ($133M) **DP Service Relays** – proactive service relay volumes decreased due to COVID-19 work restrictions ($3M) **Utilization** - Increase in regulator refit program due to increased labour costs for meter exchanges and exchanges deferred from 2021 to 2022 $10M **TPS Replacements** – reclass to System Service ($13M)
4	System Service	58.7	**TPS Replacements** - reclassed from System Renewal $13M and variance in replacement and class location programs due to pacing and scope ($3M) **Growth** – Byron Transmission delayed to 2022 in-service $20M and change in timing and scope due to changes in the growth forecast ($5M) **TPS Integrity** – Increase in large projects including Dawn-Cuthbert $34M
5	**Total - Union Rate Zones**	**(83.9)**	

2. ELIGIBILITY FOR ICM CAPITAL

21. In the MAADs Decision, the OEB confirmed the availability of ICM funding for Enbridge Gas.[20] As set out in section 4.1.5 of the "Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219", to be eligible for recovery, capital projects must meet the following criteria: materiality, need and prudence. Each of these criteria is described below in relation to Enbridge Gas's ICM funding request for 2022.

2.1 MATERIALITY

Materiality Threshold Test

22. As defined by the OEB, "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing."[21]

23. The OEB determined the formula to be used to calculate the materiality threshold as follows:

[20] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.30-34.
[21] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.

Threshold Value $= 1 + [(RB/d) * (g + PCI * (1 + g))] * ((1 + g) * (1 + PCI))^{n-1} + 10\%$

Where:

RB = Rate base included in base rates ($)

d = Depreciation expense included in base rates ($)

g = Growth factor (%)

PCI = Price cap index (%)

n = Number of years since rebasing

24. The OEB's ICM materiality threshold calculation results in a 2022 threshold value of $521.5 million for the EGD rate zone and $455.5 million for the combined Union rate zones. The materiality threshold establishes the minimum capital expenditures a utility must fund through base rates. The maximum eligible incremental capital investment for ICM funding is the amount of forecast capital expenditures in the year in excess of the threshold value. The calculation of the ICM materiality threshold value for EGD and Union rate zones is provided in Table 7 below.

Table 7
ICM Threshold Capital Expenditure Calculation by Rate Zone

Line No.	Particulars ($ millions)	EGD	Union
		(a)	(b)
1	Year	2022	2022
2	Base Year	2018	2013
3	Number of Years since rebasing (n)	4	9
4	Price Cap Index (PCI) (%)	1.40%	1.40%
5	Growth Factor (g) (%)	1.32%	1.46%
6	Dead Band (%)	10%	10%
7	Rate Base (RB)	6,246	5,331[22]
8	Depreciation (d)	305	239[23]
9	Threshold Value (%)	171%	191%
10	Threshold Value	521.5	455.5

25. A description of the Price Cap Index, growth factor, and rate base and depreciation amounts used in the threshold calculation are provided below.

[22] As per the MAADs Decision, the rate base and depreciation associated with projects that were found eligible for capital pass-through treatment during Union's 2014-2018 IRM term are added to the 2013 OEB approved rate base and depreciation.
[23] *Ibid.*

Price Cap Index

26. The OEB's threshold value calculation uses PCI to recognize the increase in revenue generated through annual rate increases in a price cap plan that could be used toward capital investment.

27. Per the 2019 Rates Decision[24], Enbridge Gas has used the current year PCI of 1.4%[25] in the ICM Threshold Capital calculation for both the EGD and Union rate zones.

Growth Factor

28. The 2022 growth factor for the EGD rate zone has been calculated by comparing the percentage difference in annual revenues between 2020 (the most recent complete year) and 2018 as the approved base year revenues. The revenue amounts are calculated at the 2018 base year rates.

29. The 2022 growth factor for the Union rate zones has been calculated by comparing the percentage difference in annual revenues between 2020 (the most recent complete year) and 2013 as the approved base year revenues. The revenue amounts are calculated at the 2013 base year rates.

30. To determine the revenue from general service rate classes, Enbridge Gas used the actual customer count and held the normalized average consumption/average use ("NAC/AU") per customer constant with the NAC/AU in base rates. This

[24] EB-2018-0305, Decision and Order, pp 15, September 12, 2019.
[25] PCI is rounded to 1 decimal place (EB-2019-0194 Decision and Interim Rate Order, December 5, 2019; Schedule A Enbridge Gas Inc. Settlement Proposal Dated November 28, 2019 Exhibit N1, Tab 1, Schedule 1, pp 8).

approach is consistent with the calculation of general service revenue in the 2019, 2020 and 2021 growth factor calculation.

31. Enbridge Gas calculated the 2020 revenue from contract rate class using weather-actual data, as contract-rate customers are generally less weather sensitive and have a higher proportion of fixed cost recovery as compared to general service customers. Table 8 below shows the calculation of the 2022 growth factor.

Table 8
2022 Growth Factor by Rate Zone

Line No.	Particulars	($ millions)
		(a)
	EGD	
1	2020 Distribution Revenues	1,257.5
2	2018 OEB-approved Distribution Revenues	1,225.1
3	2022 Growth Factor	1.32%
	Union	
4	2020 Distribution Revenues[26]	1,018.8
5	2013 OEB-approved Distribution Revenues[27]	924.0
6	2022 Growth Factor (Annualized)	1.46%

32. A detailed calculation of the revenues underpinning the growth factor for each rate zone is filed as Appendix B in this exhibit.

[26] Includes regulated distribution and transmission revenues.
[27] *Ibid.*

Rate Base and Depreciation

33. The threshold calculation uses the rate base and depreciation expense last approved by the OEB. Accordingly, the threshold value for the EGD rate zone is based on EGD's 2018 OEB-approved rate base and depreciation.

34. Pursuant to the MAADs Decision, the threshold value for the Union rate zones is based on Union's 2013 OEB-approved rate base and depreciation plus the 2019 forecast amount of rate base and depreciation associated with projects that were eligible for capital pass-through treatment and included in Union's base rates during Union's 2014-2018 IRM term.[28] The details of the rate base and depreciation amounts by rate zone are provided in Table 9 below.

[28] EB-2017-0306/EB-2017-0307, Decision and Order, September 17, 2018, p. 33.

Table 9
ICM Threshold Rate Base and Depreciation Expense by Rate Zone

Line No.	Particulars ($ millions)	Rate Base	Depreciation
		(a)	(b)
	EGD		
1	2013 OEB-Approved	6,246	305
	Union		
2	2013 OEB-Approved	3,734	196
3	2019 Capital Pass-Through Amounts[29]	1,597	43
4	Total	5,331	239

Eligible Capital Amount

35. Table 10 below compares the 2021 in-service capital forecast to the ICM materiality threshold by rate zone to calculate the maximum eligible incremental capital.

[29] EB-2018-0305, Exhibit F1, Tab 2, Rate Order, Working Papers, Schedule 16, pp. 4-5.

Table 10
Maximum Eligible Incremental Capital by Rate Zone

Line No.	Particulars ($ millions)	EGD	Union
		(a)	(b)
1	2021 In-Service Capital Forecast	734.3	543.1
2	Less: Materiality Threshold Value	521.5	455.5
3	Maximum Eligible Incremental Capital	212.8	87.6

36. The maximum eligible incremental capital for the EGD rate zone and Union rate zones is $212.8 million and $87.6 million, respectively. Enbridge Gas is seeking incremental ICM funding for specific discrete projects that fit within the maximum eligible incremental capital amount planned for each of the EGD and Union rate zones.

37. Table 11 below identifies the eligible capital projects and total in-service capital amounts for the ICM funding requests. Only projects that are discrete and material have been included.

Table 11
2022 Incremental Capital Funding Request by Rate Zone

Line No.	Particulars ($ millions)	Total Project In-service Amount	Total Project ICM Funding Request	Difference
		(a)	(b)	(c) = (b-a)
	2022 In-service Capital Forecast			
	EGD Rate Zone			
1	St. Laurent Ottawa North Replacement Phase 3	86.0	86.0	-
2	NPS 20 Replacement Cherry to Bathurst	126.7	126.7	-
	Union South Rate Zone			
3	Dawn to Cuthbert Replacement and Retrofits	23.5	23.5	-
4	Byron Transmission Station	20.4	20.4	-
	Union North Rate Zone			
5	Kirkland Lake Lateral Replacement	20.7	20.7	-
6	Total Incremental Capital Funding Request	277.3	277.3	-

2.2 NEED

Means Test

38. A distributor must also pass the Means Test in order to be eligible for ICM funding. As defined by the OEB, if a distributor's regulated return in its most recent calculation exceeds 300 basis points (bps) above the deemed return on equity

embedded in the distributor's rates, the funding for any incremental capital project will not be allowed.[30]

39. Enbridge Gas filed its 2020 Earnings Sharing and Deferral and Variance Account Clearance Application on June 4, 2021, which included its 2020 actual utility results.[31] Consistent with 2019 utility results, which was the first year the Enbridge Gas operated as an amalgamated entity, the Company has prepared its 2020 utility results on a combined/amalgamated basis. The calculated return did not exceed 300 bps above the respective OEB-approved ROE. The 2020 actual ROE was calculated to be 8.717%, which was 19.7 bps above the 2020 OEB-approved ROE of 8.52%.[32] The Enbridge Gas 2020 ROE calculation, as provided in the 2020 Earnings Sharing and Deferral and Variance Account Clearance Application, is reproduced at Appendix C of this exhibit.

Discrete and Material Projects

40. ICM funding requests must be based on discrete, material projects. As defined in the OEB ACM report, "amounts must be based on discrete projects, and should be directly related to the claimed driver. The amount must be clearly outside of the base upon which the rates were derived".[33] Also, as per the MAADs Decision, any individual project for which ICM funding is sought must have an in-service capital addition of at least $10 million.[34]

---

[30] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.15.
[31] EB-2021-0149, Exhibit B, Tab 1, Schedule 1, filed: 2021-06-04.
[32] As per the OEB's EB-2017-0306/EB-2017-0307 Decision and Order, dated August 30, 2018, during Enbridge Gas' deferred rebasing term, the determination of utility results and earnings sharing amounts will use the annual OEB-approved return on equity. In accordance with the OEB's 2020 Cost of Capital Parameters, the 2020 approved ROE was 8.52%.
[33] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, p.17.
[34] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, pp.32-33.

41. There are four Replacement projects and one Station project for which Enbridge Gas is seeking ICM funding, the St. Laurent Ottawa North Replacement Phase 3 and the NPS 20 Replacement Cherry to Bathurst in the EGD rate zone and the Dawn to Cuthbert Replacement and Retrofits and Byron Transmission Station in the Union South rate zone and the Kirkland Lake Lateral Replacement in the Union North rate zone.

42. Each eligible capital project as identified for the EGD rate zone and Union rate zones is a discrete project that exceeds the materiality level of $10 million. These projects have been evaluated as part of the capital planning process, described in the AMP as discussed at Section 1. Each project is distinct, with significant influence on Enbridge Gas's operations as described at Exhibit B, Tab 2, Schedule 2.

St. Laurent Ottawa North Replacement Phase 3

43. Enbridge Gas filed a Leave to Construct application with the OEB for the St. Laurent Ottawa North Replacement Phase 3 Project on March 2nd, 2021 under docket number EB-2020-0293. A revised Leave to Construct application was filed on September 10th, 2021. This project is needed to replace approximately 16 km of NPS 12 extra high pressure (XHP) steel gas main and approximately 400 m of NPS 16 XHP steel gas main in the city of Ottawa. The project will be completed in multiple phases over multiple years. The existing pipeline services over 165,000 customers in Ottawa, Ontario and Gatineau, Quebec and feeds 12 district regulating stations and one header station, including a large population of non-interruptible residential, industrial and commercial customers and a natural gas fired power plant. The project is required due to integrity issues with the existing pipeline and is necessary to maintain the safe and reliable delivery of natural gas to the

Ottawa and Gatineau regions. The St. Laurent project consists of four phases. Phase 2 of the project was approved as part of the Decision and Order in EB-2019-0006 and was placed into service in September, 2020. For ICM eligibility purposes, each phase of the project has been evaluated individually based on the total in-service capital of that phase. In this application, Enbridge Gas is seeking ICM funding for Phase 3 of the project with a projected in-service date of December 2022. Enbridge Gas has determined that the replacement of the St. Laurent Pipeline is needed to ensure the safe and reliable supply of natural gas to customers in Ottawa and Gatineau. The Business Case for this project is filed at Exhibit B, Tab 2, Schedule 2.

<u>NPS 20 Replacement Cherry to Bathurst</u>

44. Enbridge Gas filed a Leave to Construct application with the OEB for the NPS 20 Replacement Cherry to Bathurst on July 31st, 2020 under docket number EB-2020-0136. The OEB approved the Leave to Construct application on December 17, 2020. This project is needed to replace approximately 4.5 km of steel gas distribution main on Lake Shore Boulevard from Cherry Street to Bathurst Street and a 260 m section on Parliament Street from Mill Street to Lake Shore Boulevard East (C2B) in the City of Toronto. The segment to be replaced is part of the natural gas main known as the Kipling Oshawa Loop (KOL). The area served by the C2B segment of the KOL has the highest density of customers within the Enbridge Gas franchise area and is one of the largest economic centers in Canada. Types of customers served include residential, commercial, institutional (including hospitals), government buildings and large volume customers. The project is required to address integrity issues identified through the Enbridge Gas Distribution Integrity Management Program (DIMP). The replacement of the C2B segment as proposed will allow Enbridge Gas to continue to provide natural gas to customers in

the City of Toronto in a safe and reliable manner. The Business Case for this project is filed at Exhibit B, Tab 2, Schedule 2.

Dawn to Cuthbert Replacement and Retrofits

45. Enbridge Gas has identified the need to replace approximately 650 m of the existing NPS 42 Dawn to Cuthbert pipeline to mitigate pipeline integrity concerns in the Township of Dawn-Euphemia, in the County of Lambton, Ontario. The project is a like-for-like replacement of pipeline and does not require Leave to Construct approval. The NPS 42 Dawn to Cuthbert pipeline supplies the NPS 42 Dawn to Kirkwall pipeline, which is one of four parallel pipelines that forms the Dawn Parkway System. The Dawn Parkway System is the backbone gas transmission system that serves the demands of millions of customer located in Ontario, Quebec, Eastern Canada and the U.S. Northeast. The project is required to address integrity issues identified through the Enbridge Gas Transmission Integrity Management Program (TIMP). Replacement of the pipeline completely mitigates the threat of Stress Corrosion Cracking (SCC), has a more substantial reduction of risk and better enhances the safely and reliability of the pipeline. The Business Case for this project is filed at Exhibit B, Tab 2, Schedule 2. Additionally, Enbridge Gas has prepared evidence similar to what would be filed in an LTC application in relation to the items relevant to an ICM determination (purpose, need and timing, alternatives and project costs). This evidence is filed at Exhibit B, Tab 2, Schedule 2, Appendix A.

Byron Transmission Station

46. Enbridge Gas identified the need to rebuild the Byron Transmission Station located on Enbridge Gas-owned property in the community of Byron in London, Ontario. The project is not subject to a Leave to Construct approval requirement. The Station accepts gas from the Dawn Parkway System and supplies natural gas to

the majority of the London, St. Thomas and Port Stanley systems. Based on results from an indirect heater assessment conducted by Enbrige Gas, integrity concerns were identified. There have also been noise concerns, maintenance and operations concerns and the Station is unable to support the long term demands of the London market. Rebuilding the Byron Transmission Station will address the concerns identified and will provide adequate capacity to support future demand. The Business Case for this project is filed at Exhibit B, Tab 2, Schedule 2. Additionally, Enbridge Gas has prepared evidence similar to what would be filed in an LTC application in relation to the items relevant to an ICM determination (purpose, need and timing, alternatives and project costs). This evidence is filed at Exhibit B, Tab 2, Schedule 2, Appendix B.

<u>Kirkland Lake Lateral Replacement</u>

47. Enbridge Gas has identified the need to replace the existing NPS 4 Kirkand Lake Lateral running through the Municipality of Kirkland Lake in District of Timiskaming with 8 km of NPS 4 pipeline. The project is a like-for-like replacement of pipeline and does not require a Leave to Construct approval. The current system includes two lines, the existing Kirkland Lake Lateral in scope for replacement and the NPS 8 Kirkland Lake Loop. The pipelines primarily serve approximately 3,126 customers in the towns of Kirkland Lake, Chaput Hughes, Swastika and the Macassa Mines. Based on the results of the Integrity and Risk Assessment, Enbridge Gas has concluded that the existing lines are an operational risk and should be replaced in order to maintain the safety and reliability of natural gas distribution to the Municipality of Kirkland Lake. The Business Case for this project is filed at Exhibit B, Tab 2, Schedule 2. Additionally, Enbridge Gas has prepared evidence similar to what would be filed in an LTC application in relation to the items relevant to an ICM determination (purpose, need and timing, alternatives and project costs). This evidence is filed at Exhibit B, Tab 2, Schedule 2, Appendix C.

2.3 Prudence

48. The capital expenditures of the projects for which Enbridge Gas is seeking ICM funding approval for the EGD rate zone and Union rate zones are prudent and represent the most cost effective option for ratepayers.

49. The business case summaries filed at Exhibit B, Tab 2, Schedule 2 provide a description of each of the projects' need and prudence, with an overview of options considered.

3. CALCULATION OF REVENUE REQUIREMENT

50. Table 12 provides the incremental revenue requirement Enbridge Gas is seeking as ICM funding for 2022 ICM projects. The total capital cost of the 2022 ICM funding request is $277.3 million with an associated total revenue requirement of $10.8 million from 2022 to 2023 and an average annual revenue requirement of $5.4 million. The incremental revenue requirement includes costs associated with the capital investment (return on rate base, depreciation expense and associated income taxes) only.

Table 12
Total Incremental Revenue Requirement by Rate Zone

Line No.	Particulars ($000's)	2022	2023	Total	Average Annual
		(a)	(b)	(c)	(d) = (c)/2
	EGD Rate Zone				
1	St. Laurent Ottawa North Replacement Phase 3	(4,594)	7,440	2,846	1,423
2	NPS 20 Replacement Cherry to Bathurst	(4,953)	11,102	6,150	3,075
	Union South Rate Zone				
3	Dawn to Cuthbert Replacement and Retrofits	(1,034)	2,024	989	495
4	Byron Transmission Station	(1,896)	1,473	(422)	(211)
	Union North Rate Zone				
5	Kirkland Lake Lateral Replacement	(936)	2,199	1,264	632
6	Total Incremental Revenue Requirement	(13,412)	24,238	10,826	5,413

51. The detailed incremental revenue requirement for each of the 2022 ICM projects for the deferred rebasing period is filed as Appendix E in this exhibit.

52. The return on rate base is calculated using the cost of capital parameters approved by the OEB in EGD's 2018 Rate Adjustment Application (EB 2017-0086) for the EGD rate zone and in Union's 2013 Cost of Service application (EB 2011-0210) for the Union rate zones.

53. Depreciation expense is calculated using OEB-approved depreciation rates beginning the month following the in-service date of the project in accordance with the accounting policies of Enbridge Gas.

54. Incremental income taxes as a result of the projects are calculated using the current tax rates. Income taxes include taxes on the equity and preference share return on rate base as well as the utility timing differences associated with the difference between utility income and taxable income, and reflect 100% of the impacts of the accelerated Capital Cost Allowance.[35] Income taxes are grossed up to account for the impact the additional revenue will have on income tax expense.

55. The 2023 in-service capital forecast of the 2022 ICM Projects will be included in the in-service capital for purposes of determining the maximum eligible incremental capital in 2023.

4. COST ALLOCATION

56. Enbridge Gas is proposing to allocate the ICM Project revenue requirement to rate classes based on the most recently approved cost allocation methodology updated for the current year forecast.

57. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the St. Laurent Ottawa North Replacement Phase 3 project among different rate classes in EGD rate zone according to the most recent OEB approved cost allocation methodology (EB-2017-0086) for the low pressure mains. The

---

[35] On June 21, 2019, Bill C-97, the Budget Implementation Act, 2019, No.1, was given Royal Assent. Bill C-97 includes an “Accelerated Investment Incentive” program which provides for a first-year increase in Capital Cost Allowance (“CCA”) deductions on eligible capital assets acquired after November 20, 2018 (“Accelerated CCA”).

allocator can be found at EB-2017-0086, Exhibit G2, Tab 6, Schedule 3, page 2, Item 2.4 (Delivery Demand LP allocator).

58. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the NPS 20 Replacement Cherry to Bathurst project among different rate classes in the EGD rate zone according to the most recent OEB approved cost allocation methodology (EB-2017-0086) for the high pressure mains. The allocator can be found at EB-2017-0086, Exhibit G2, Tab 6, Schedule 3, page 2, Item 2.3 (Delivery Demand HP allocator).

59. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the Dawn to Cuthbert Replacement and Retrofits project to Union rate classes in proportion to the forecast distance weighted design day demands (commodity-kilometres) on the Dawn-Parkway transmission system. This proposed cost allocation methodology is consistent with the allocation of Dawn-Parkway transmission system demand costs most recently approved by the OEB in EB-2011-0210 (Union's 2013 approved cost allocation study). The allocation of Dawn-Parkway Easterly Demand costs recognizes how the Dawn-Parkway transmission system meets Union in-franchise and ex-franchise demands on design day.

60. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the Byron Transmission Station project to Union South rate classes in proportion to the forecast Union South in-franchise design day demands. This proposed cost allocation methodology is consistent with the allocation of Other Transmission Demand costs approved by the OEB in EB-2011-0210 (Union's 2013 approved cost allocation study). The allocation of Other Transmission costs

recognizes other transmission lines are designed to meet Union South in-franchise demands on design day.

61. Enbridge Gas proposes to allocate the annual average net revenue requirement with respect to the Kirkland Lake Lateral Replacement project to Union North rate classes in proportion to the forecast Union North Peak and Average Day Demands excluding customers who are entirely Sole Use. This proposed cost allocation methodology is consistent with the allocation of joint use mains costs approved by the OEB in EB-2011-0210 (Union's 2013 approved cost allocation study). The allocation of joint use mains costs recognizes that joint use mains are designed to meet Union North in-franchise demands, excluding the demands of customers served directly off of sole use mains.

62. The cost allocation factors and the allocation of project revenue requirement to the rate classes for each of the 2022 ICM projects are filed as Appendix F in this exhibit.

5. ICM UNIT RATES

63. Enbridge Gas is seeking approval of ICM unit rates beginning in 2022 for the duration of the deferred rebasing period to recover the total revenue requirement of the 2022 ICM projects from 2022 to 2023 as part of this proceeding. To calculate the ICM unit rates, Enbridge Gas used the allocated average annual revenue requirement and the forecast 2022 billing units for each respective rate class. Consistent with the treatment of 2019, 2020 and 2021 approved ICM project unit rates, Enbridge Gas proposes to embed the ICM unit rates in the delivery and transportation charges on the applicable rate schedule and customer bill. The

derivation of the ICM unit rates for 2022 ICM projects is filed as Appendix G in this exhibit.

64. The ICM unit rates presented in Appendix G were prepared assuming an implementation date in rates of January 1, 2022. Following the OEB's Decision in this proceeding, Enbridge Gas will file a draft rate order including updated ICM unit rates to reflect recovery of the total revenue requirement of the projects for the deferred rebasing period beginning with the implementation date if different than January 1, 2022.

6. ICM BILL IMPACTS

65. The bill impact associated with the 2022 ICM funding request for a typical Rate 1 residential customer consuming 2,400 m^3 annually in the EGD rate zone is an increase of $1.11.[36]

66. The bill impact associated with the 2022 ICM funding request for a typical Rate M1 residential customer consuming 2,200 m^3 annually in the Union South rate zone is a decrease of $0.06.

67. The bill impact associated with the 2022 ICM funding request for a typical Rate 01 residential customer consuming 2,200 m^3 annually in the Union North rate zone is an increase of $0.55.

68. The ICM bill impacts by rate class are filed as Appendix H for the EGD rate zone and Appendix I for the Union rate zones.

---

[36] The increase in Union South Rate M12 demand charges has a total bill impact of less than $0.05 on a typical Rate 1 residential customer in the EGD rate zone.

CAPITAL BUDGET AND ICM FUNDING CALCULATIONS BASED ON PREVIOUSLY OEB-APPROVED OVERHEAD CAPITALITIZATION POLICY

1. As directed by the OEB in the 2021 Rates proceeding (EB-2020-0181)[1], Enbridge Gas is required to include capital budget and ICM funding calculations based on both the previously OEB-approved and the new harmonized overhead capitalization policies in any future ICM application filed during the deferred rebasing period.

2. The tables below shows the 2022 capital budget and the ICM funding calculations based on the previously OEB-approved capitalization policy.

1. 2022 CAPITAL BUDGET

3. The 2022 capital investment budget[2] are shown in Table A for the EGD rate zone and Table B for the Union rate zones.

[1] EB-2020-0181, Decision and Order, May 6, 2021, p.20.
[2] In-service capital.

Table A
2022 Capital Investment by category
EGD Rate Zone ($ millions)

Line No.	Category	Previous Overhead Capitalization Policy	New Harmonized Overhead Capitalization Policy[3]	Difference
		(a)	(b)	(c) = (b)-(a)
1	General Plant	80.9	81.0	0.1
2	System Access	150.6	151.9	1.3
3	System Renewal	463.9	465.3	1.4
4	System Service	36.1	36.1	-
5	**Total - EGD Rate Zone**	**731.5**	**734.3**	**2.8**

Table B
2022 Capital Investment by category
Union Rate Zones ($ millions)

Line No.	Category	Previous Overhead Capitalization Policy	New Harmonized Overhead Capitalization Policy[4]	Difference
		(a)	(b)	(c) = (b)-(a)
1	General Plant	69.5	70.1	0.6
2	System Access	120.2	120.6	0.4
3	System Renewal	199.6	200.6	1.0
4	System Service	150.5	151.8	1.3
5	**Total - Union Rate Zones**	**539.8**	**543.1**	**3.4**

[3] Exhibit B, Tab 2, Schedule 1, Table 1.
[4] Exhibit B, Tab 2, Schedule 1, Table 2.

2. MAXIMUM ICM ELIGIBLE CAPITAL AMOUNT AND ICM PROJECTS

4. Table C below compares the 2022 in-service capital forecast based on the previously OEB-approved capitalization policy to the ICM materiality threshold by rate zone to calculate the maximum eligible incremental capital.

Table C
Maximum Eligible Incremental Capital by Rate Zone

Line No.	Particulars ($ millions)	**Previous Overhead Capitalization Policy** EGD	Union	**New Harmonized Overhead Capitalization Policy**[5] EGD	Union	**Difference** EGD	Union
		(a)	(b)	(c)	(d)	(e)=(c)-(a)	(f)=(d)-(d)
1	2021 In-Service Capital Forecast	731.5	539.8	734.3	543.1	2.8	3.4
2	Less: Materiality Threshold Value	521.5	455.5	521.5	455.5	-	-
3	Maximum Eligible Incremental Capital	210.0	84.3	212.8	87.6	2.8	3.4

5. Table D below identifies the eligible capital projects and total in-service capital amounts for the ICM funding requests based on the previously OEB-approved capitalization policy.

[5] Exhibit B, Tab 2, Schedule 1, Table 10.

Table D
2022 Incremental Capital Funding Request by Rate Zone

Line No.	Particulars ($ millions)	Previous Overhead Capitalization Policy		New Harmonized Overhead Capitalization Policy[6]		Difference	
		Total Project In-service Amount	Total Project ICM Funding Request	Total Project In-service Amount	Total Project ICM Funding Request	Total Project In-service Amount	Total Project ICM Funding Request
		(a)	(b)	(d)	(e)	(f)=(d)-(a)	(g)=(e)-(b)
	2022 In-service Capital Forecast						
	EGD Rate Zone						
1	St. Laurent Ottawa North Replacement Phase 3	85.3	82.5	86.0	86.0	0.7	3.5
2	NPS 20 Replacement Cherry to Bathurst	127.0	127.0	126.7	126.7	(0.3)	(0.3)
	Union South Rate Zone						
3	Dawn to Cuthbert Replacement and Retrofits	23.4	23.4	23.5	23.5	0.1	0.1
4	Byron Transmission Station	19.7	19.7	20.4	20.4	0.7	0.7
	Union North Rate Zone						
5	Kirkland Lake Lateral Replacement	20.6	20.6	20.7	20.7	0.1	0.1
6	Total Incremental Capital Funding Request	276.0	273.2	277.3	277.3	1.3	4.1

[6] Exhibit B, Tab 2, Schedule 1, Table 11.

3. CALCULATION OF REVENUE REQUIREMENT

6. Table E provides the incremental revenue requirement for the ICM projects based on the previously OEB-approved capitalization policy. The incremental revenue requirement includes costs associated with the capital investment (return on rate base, depreciation expense and associated income taxes) only.

Table E
Total Incremental Revenue Requirement by Rate Zone

Line No.	Particulars ($000's)	Previous Overhead Capitalization Policy 2022 (a)	2023 (b)	Total (c)	Annual Average (d)	New Harmonized Overhead Capitalization Policy[7] 2022 (e)	2023 (f)	Total (g)	Annual Average (h)	Difference Annual Average (i)=(h)-(d)
	EGD Rate Zone									
1	St. Laurent Ottawa North Replacement Phase 3	(3,665)	7,403	3,737	1,869	(4,594)	7,440	2,846	1,423	(446)
2	NPS 20 Replacement Cherry to Bathurst	(3,746)	11,143	7,397	3,699	(4,953)	11,102	6,150	3,075	(624)
	Union South Rate Zone									
3	Dawn to Cuthbert Replacement and Retrofits	(994)	2,009	1,015	508	(1,034)	2,024	989	495	(13)
4	Byron Transmission Station	(1,768)	1,413	(355)	(178)	(1,896)	1,473	(422)	(211)	(34)
	Union North Rate Zone									
5	Kirkland Lake Lateral Replacement	(901)	2,187	1,286	643	(936)	2,199	1,264	632	(11)
6	Total Incremental Revenue Requirement	(11,074)	24,155	13,080	6,540	(13,412)	24,238	10,826	5,413	(1,127)

[7] Exhibit B, Tab 2, Schedule 1, Table 12.

Table A
General Plant Capital Expenditures[1] by Category (2017-2026)
EGD Rate Zone ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	Equipment & Materials	2.4	2.1	0.1	2.3	1.5	3.9	4.1	4.2	4.1	4.4
2	Furniture/Structures & Improvements	9.4	8.7	33.6	15.1	53.4	28.2	102.1	6.2	28.6	44.9
3	IT Implementation	27.7	32.7	22.3	25.5	16.9	35.3	26.5	72.3	57.1	66.4
4	Land – Storage	-	-	-	-	0.2	0.2	1.5	1.6	1.5	1.6
5	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-
6	Structures and Improvement - Storage	-	0.2	-	-	-	-	-	-	-	-
7	Tools	-	1.3	7.3	2.3	1.9	7.3	1.2	1.2	1.2	1.3
8	Vehicles	6.6	2.3	7.1	6.2	6.2	6.1	6.3	6.6	6.4	6.8
9	WAMS	2.0	-	-	-	-	-	-	-	-	-
10	**General Plant - EGD Rate Zone**	**48.1**	**47.3**	**70.4**	**51.3**	**80.2**	**81.0**	**141.7**	**92.1**	**99.0**	**125.5**

[1] Overheads are included in project costs in years 2021-2026.

Table B

General Plant Capital Expenditures[2] by Category (2017-2026)

Union Rate Zones ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	Tools	2.7	2.0	1.5	1.7	2.0	2.2	2.1	2.1	2.1	2.2
2	Equipment & Materials	-	-	-	-	3.7	3.9	4.0	4.1	4.0	4.3
2	LNG Capital Maintenance	0.2	-	-	-	-	-	-	-	-	-
3	Measurement Electronics Upgrades	0.1	0.8	-	-	-	-	-	-	-	-
4	Compressor and Dehy Capital Maintenance	-	1.4	-	-	-	-	-	-	-	-
5	Fleet Vehicles	6.2	7.7	12.4	7.8	5.9	8.7	6.4	6.7	6.5	7.0
6	Land – Storage, Transmission & LNG	0.3	-	-	11.7	0.7	4.2	0.3	0.3	0.3	0.3
7	Leasehold Improvements	9.1	12.3	7.7	4.4	39.8	38.3	57.7	12.9	30.8	26.4
8	Other - Indirect Materials	0.3	-	0.2	-	-	-	-	-	-	-
9	Service Facilities - Dawn	1.5	-	-	-	-	-	-	-	-	-
10	IT Implementation	22.4	23.8	30.0	8.6	10.9	12.1	7.3	17.2	6.9	9.2
11	**General Plant - Union Rate Zones**	**42.8**	**48.0**	**51.8**	**34.2**	**64.4**	**70.1**	**84.0**	**49.8**	**56.9**	**56.1**

[2] Overheads are included in project costs in years 2021-2026.

Table C
System Access Capital Expenditures[3] by Category (2017-2026)
EGD Rate Zone ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	Commercial	19.5	19.8	25.5	24.2	29.2	25.6	-	-	-	-
2	Industrial	3.9	(1.9)	0.3	0.3	5.5	4.8	-	-	-	-
3	Meters - Capital Purchase Program (Growth)	6.7	5.1	12.1	7.5	8.9	7.0	9.5	9.6	9.2	9.5
4	NGV	2.1	7.2	1.3	1.6	1.1	1.3	0.9	0.9	0.9	1.0
5	Hydrogen Blending	-	-	-	-	-	4.9	-	-	-	-
6	Rebillable Relocations	3.5	(2.7)	46.1	(94.0)	11.1	(6.1)	8.4	37.7	11.9	12.5
7	Residential	70.8	81.4	65.6	130.6	131.3	114.4	143.2	145.2	138.5	143.0
8	Sales Stations - New	2.8	-	0.2	0.3	5.7	-	-	-	-	-
9	**System Access - EGD Rate Zone**	**109.3**	**108.9**	**151.1**	**70.5**	**192.8**	**151.9**	**169.5**	**201.0**	**168.1**	**173.6**

Table D
System Access Capital Expenditures[4] by Category (2017-2026)
Union Rate Zones ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	CNG	-	-	-	0.1	2.2	3.1	-	-	-	-
2	Transmission Growth	-	-	-	-	(0.9)	0.4	63.9	(0.9)	0.9	-
3	Meters – Capital Purchase Program (Growth)	-	-	-	3.6	8.6	4.5	9.7	10.2	10.1	11.0
4	General Customer Growth	70.0	66.7	85.2	63.6	80.2	84.5	82.1	83.5	80.0	83.6
5	Municipal Replacement	26.2	16.8	19.2	18.2	29.4	28.2	30.0	30.7	29.3	30.9
6	**System Access - Union Rate Zones**	**96.2**	**83.5**	**104.4**	**85.5**	**119.5**	**120.6**	**213.2**	**126.5**	**123.0**	**128.3**

[3] Overheads are included in project costs in years 2021-2026.
[4] Overheads are included in project costs in years 2021-2026.

Table E

System Renewal Capital Expenditures[5] by Category (2017-2026)

EGD Rate Zone ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	Compressor Equipment - Storage	9.7	6.9	0.2	23.2	40.1	44.1	226.8	14.4	18.4	43.5
2	Corrosion Prevention	1.3	1.9	3.2	2.6	3.9	3.2	3.3	3.3	3.2	3.3
3	Field Lines - Storage	0.5	0.3	-	-	-	-	-	-	-	-
4	Gate & Feeder Stations	5.2	6.2	1.4	49.3	22.8	49.1	33.0	45.2	27.5	27.8
5	Inside Regulator Program	3.1	0.8	0.1	1.9	0.1	-	-	-	-	-
6	Integrity Digs	1.9	(0.6)	1.2	2.3	-	-	-	-	-	-
7	Integrity Retrofit	0.9	1.1	0.4	-	-	-	-	-	-	-
8	Main Replacement	16.1	19.9	13.0	63.2	42.7	279.9	85.3	124.7	119.3	124.9
9	Transmission Pipe – Improvements & Replacements	-	-	-	20.7	29.9	6.3	9.3	8.7	5.3	8.9
10	Meters - Capital Purchase Program (Maintenance)	15.7	11.8	28.2	10.4	11.1	20.0	21.5	29.1	20.5	26.1
11	Non-Rebillable Relocations	-	1.3	2.5	1.6	-	-	-	-	-	-
12	Regulator Refit	12.3	14.0	29.2	15.0	18.4	19.2	23.3	24.4	23.5	25.0
13	Remediation - Customer Assets	1.0	1.0	2.0	-	0.9	0.8	0.6	0.6	0.6	0.6
14	Service Relay	21.6	19.7	22.4	25.6	39.2	31.6	43.9	47.7	54.9	65.7
15	Station Rebuilds	9.9	6.5	5.9	17.8	13.5	10.9	13.7	15.5	15.1	16.1
16	Wells and Well Equipment - Storage	3.0	1.5	0.7	-	-	-	-	-	-	-
17	**System Renewal - EGD Rate Zone**	**102.2**	**92.3**	**110.4**	**233.6**	**223.0**	**465.3**	**460.5**	**313.6**	**288.3**	**342.0**

[5] Overheads are included in project costs in years 2021-2026.

Table F
System Renewal Capital Expenditures[6] by Category (2017-2026)
Union Rate Zones ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	Bare and Unprotected steel	-	-	3.7	-	-	-	-	-	-	-
2	Corrosion Prevention	7.2	5.9	7.0	4.3	8.5	9.9	7.5	9.0	8.5	9.0
3	Compression Equipment - Storage	0.9	0.1	1.0	6.8	9.4	12.1	10.4	44.7	115.7	88.7
4	Compressor Overhauls	0.6	-	-	-	1.1	3.6	3.8	3.9	3.8	4.1
5	Excess Flow Valves	0.2	-	-	-	-	-	-	-	-	-
6	Transmission Equipment - Storage	-	-	-	10.3	1.3	2.3	3.6	35.9	8.2	4.4
7	Main Replacement	32.4	45.1	33.7	61.1	196.2	62.8	46.9	109.1	117.2	149.3
8	Service Relay	-	-	-	3.7	4.7	4.1	7.1	8.0	7.8	8.3
9	Leakage	-	-	2.9	-	-	-	-	-	-	-
10	LNG Capital Maintenance	1.9	0.1	-	0.1	0.2	-	0.8	0.8	99.7	0.8
11	Measurement Electronics Upgrades	2.0	0.3	0.9	-	-	-	-	-	-	-
12	Meter Exchange Program	29.4	32.7	43.4	17.9	27.7	19.7	31.0	32.7	32.2	35.2
13	Regulator Refit	-	-	-	11.0	19.4	36.1	18.9	19.2	18.9	19.8
14	Station Rebuilds	-	-	-	5.6	16.5	34.5	38.8	40.3	39.1	41.9
15	Gate & Feeder Stations	-	-	-	20.8	21.2	15.5	1.2	-	-	-
16	Service Replacement	4.6	5.0	3.2	-	-	-	-	-	-	-
17	Station Painting	0.2	1.8	2.1	-	-	-	-	-	-	-
18	Stations Capital Maintenance	10.9	8.4	6.3	-	-	-	-	-	-	-
19	General Pipeline Maintenance	3.8	-	2.2	-	-	-	-	-	-	-
20	**System Renewal - Union Rate Zones**	**94.1**	**99.4**	**106.4**	**141.6**	**306.3**	**200.6**	**169.9**	**303.9**	**451.2**	**361.6**

[6] Overheads are included in project costs in years 2021-2026.

Table G
System Service Capital Expenditures[7] by Category (2017-2026)
EGD Rate Zone ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	Carbon Capture	-	-	-	-	-	-	-	-	-	-
2	Integrity Initiatives	4.7	6.7	7.1	10.1	20.5	30.1	29.5	32.0	30.9	32.5
3	MOP	1.4	1.4	0.2	3.0	-	-	-	-	-	-
4	Records Integrity	4.6	4.9	9.5	0.5	-	-	-	-	-	-
5	System Reinforcement	4.7	9.9	7.1	7.2	14.1	2.9	10.6	36.5	76.6	12.9
6	GTA	4.8	-	-	-	-	-	-	-	-	-
7	**System Service - EGD Rate Zone**	**20.2**	**22.9**	**23.9**	**20.8**	**34.5**	**36.1**	**42.0**	**68.5**	**107.4**	**45.4**

[7] Overheads are included in project costs in years 2021-2026.

Table H
System Service Capital Expenditures[8] by Category (2017-2026)
Union Rate Zones ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Fcast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
1	Excess Flow Valves	0.7	-	-	-	-	-	-	-	-	-
2	General Mains	-	-	-	-	-	-	-	-	-	-
3	Integrity Initiatives	23.3	22.7	37.7	46.4	72.8	95.5	74.9	77.8	74.5	78.9
4	LNG Capital Maintenance	0.1	-	-	-	0.4	0.2	-	-	-	-
5	Measurement Electronics Upgrades	-	-	0.1	-	-	-	-	-	-	-
6	Measurement Upgrade	-	-	-	-	-	-	-	-	-	-
7	Distribution Reinforcement	9.3	16.5	18.2	-	-	-	-	-	-	-
8	Emissions Action Plan	4.1	-	0.1	-	-	-	-	-	-	-
9	Monitoring Systems	-	-	-	-	0.2	0.2	0.0	0.0	0.0	0.0
10	Odourant Upgrades	0.7	0.6	1.0	-	-	-	-	-	-	-
11	Station Reinforcement	-	0.1	0.7	-	-	-	-	-	-	-
12	Storage Improvements	1.1	2.0	0.6	-	-	-	-	-	-	-
13	System Growth	366.4	159.3	81.5	-	-	-	-	-	-	-
14	System Reinforcement	-	-	-	70.6	32.1	55.9	47.2	66.0	78.3	163.1
15	Transmission Reinforcement	-	-	22.2	-	39.9	-	120.2	1.5	210.3	-
16	Integrated Resource Planning	0.1	-	-	-	-	-	-	-	-	-
17	**System Service - Union Rate Zones**	**405.8**	**201.2**	**162.1**	**117.0**	**145.4**	**151.8**	**245.9**	**155.5**	**372.8**	**252.4**

[8] Overheads are included in project costs in years 2021-2025.

EGD RATE ZONE
Calculation of 2020 and 2018 Revenue at 2018 Approved Rates

Line No.	Particulars	Billing Units (a)	Rates (cents / m^3) (b)	2018 Approved Usage (c)	2018 Revenue ($000's) (d)	2020 Actual Usage (e)	2020 Revenue ($000's) (f)
	Rate 1 General Service						
1	Customer Charge	bills	$ 20.00	24,180,918	483,618	24,774,376	495,488
2	Delivery Charge		6.7333	4,751,509	319,931	4,868,122	327,783
3	Load Balancing	10^3 m^3	0.3411	4,750,232	16,203	4,866,814	16,601
4	Transportation	10^3 m^3	0.0235	4,634,556	1,089	4,748,299	1,116
5	Transportation Dawn	10^3 m^3	0.0078	82,881	6	84,915	7
6	Gas Supply Commodity - System	10^3 m^3	0.0780	4,583,611	3,575	4,696,104	3,663
7	Total Rate 1				824,423		844,657
	Rate 6 General Service						
8	Monthly Charge	bills	$ 70.00	2,010,770	140,754	2,029,003	142,030
9	Delivery Charge		3.7157	4,801,738	178,416	4,845,279	180,034
10	Load Balancing	10^3 m^3	0.3202	4,829,758	15,465	4,873,552.32	15,605
11	Transportation	10^3 m^3	0.0235	3,620,680	851	3,653,511.27	859
12	Transportation Dawn	10^3 m^3	0.0078	895,132	70	903,248.35	70
13	Gas Supply Commodity - System	10^3 m^3	0.0993	3,121,315	3,099	3,149,617.69	3,128
14	Total Rate 6				338,655		341,726
	Rate 9 Contract Service						
15	Monthly Charge	bills	$ 235.95	-	-	-	-
	Delivery Charge						
16	First 20,000 m^3	10^3 m^3	11.2489	-	-	-	-
17	Over 20,000 m^3	10^3 m^3	10.5292	-	-	-	-
18	Load Balancing	10^3 m^3	0.0196	-	-	-	-
19	Transportation	10^3 m^3	0.0235	-	-	-	-
20	Transportation Dawn	10^3 m^3	0.0078				
21	Gas Supply Commodity - System	10^3 m^3	0.0431	-	-	-	-
22	Total Rate 9				-		-

EGD RATE ZONE
Calculation of 2020 and 2018 Revenue at 2018 Approved Rates

Line No.	Particulars		Billing Units	Rates (cents / m^3)	2018 Approved Usage	2018 Revenue ($000's)	2020 Actual Usage	2020 Revenue ($000's)
			(a)	(b)	(c)	(d)	(e)	(f)
	Rate 100 Contract Service							
1	Monthly Charge		bills	$ 122.01	-	-	111	14
2	Contract Demand		10^3 m^3	36.00	-	-	4,804	1,729
3	Load Balancing		10^3 m^3	0.3202	-	-	19,356	62
4	Transportation		10^3 m^3	0.0236	-	-	9,482	2
5	Transportation Dawn		10^3 m^3	0.0078	-	-	9,874	1
6	Gas Supply Commodity - System		10^3 m^3	0.0993	-	-	9,482	9
7	Total Rate 100					-		1,817
	Rate 110 Contract Service							
8	Monthly Charge		bills	$ 587.37	3,180	1,868	4,023	2,363
9	Contract Demand		10^3 m^3	22.91	48,218	11,047	82,640	18,933
	Delivery Charge			-				
10	First	1,000,000 m^3	10^3 m^3	0.5671	639,885	3,629	773,009	4,384
11	Over	1,000,000 m^3	10^3 m^3	0.4171	149,151	622	205,597	858
12	Load Balancing		10^3 m^3	0.0713	789,036	563	978,606	698
13	Transportation		10^3 m^3	0.0235	216,486	51	84,417	20
14	Transportation Dawn		10^3 m^3	0.0078	474,890	37	828,935	65
15	Gas Supply Commodity - System		10^3 m^3	0.0433	56,322	24	71,898	31
16	Total Rate 110					17,840		27,350
	Rate 115 Contract Service							
17	Monthly Charge		bills	$ 622.62	324	202	240	149
18	Contract Demand		10^3 m^3	24.36	20,166	4,912	14,579	3,552
	Delivery Charge							
19	First	1,000,000 m^3	10^3 m^3	0.2227	170,833	380	140,134	312
20	Over	1,000,000 m^3	10^3 m^3	0.1228	371,998	457	238,322	293
21	Load Balancing		10^3 m^3	0.0253	542,831	137	378,456	96
22	Transportation		10^3 m^3	0.0236	11,292	3	728	0
23	Transportation Dawn		10^3 m^3	0.0078	362,012	28	251,523	20
24	Gas Supply Commodity - System		10^3 m^3	0.0433	-	-	728	0
25	Total Rate 115					6,120		4,422
	Rate 125 Contract Service							
26	Monthly Charge		bills	$ 500.00	48	24	48	24
27	Contract Demand		10^3 m^3	10.0427	111,124	11,160	111,124	11,160
28	Total Rate 125					11,184		11,184

EGD RATE ZONE
Calculation of 2020 and 2018 Revenue at 2018 Approved Rates

Line No.	Particulars	Billing Units (a)	Rates (cents / m^3) (b)	2018 Approved Usage (c)	2018 Revenue ($000's) (d)	2020 Actual Usage (e)	2020 Revenue ($000's) (f)
	Rate 135 Contract Service						
	Winter (December to March)						
1	Monthly Charge	bills	$ 115.08	172	19.79	134	15
	Delivery Charge						
2	First 14,000 m³	10³ m³	7.0437	664	46.79	540	38
3	Next 28,000 m³	10³ m³	5.8445	1,026	59.98	896	52
4	Over 42,000 m³	10³ m³	5.4446	2,010	109.44	2,989	163
	Rate 135 Contract Service						
	Summer (April to November)						
	Monthly Charge	bills	$ 115.08	344	40	349	40
	Delivery Charge						
5	First 14,000 m³	10³ m³	2.3073	4,514	104.15	4,349	100
6	Next 28,000 m³	10³ m³	1.6073	8,724	140.23	8,182	132
7	Over 42,000 m³	10³ m³	1.4074	47,562	669.39	47,481	668
8	Load Balancing	10³ m³	-	64,501	-	60,104	-
9	Transportation	10³ m³	0.0235	18,862	4.43	7,215	2
10	Transportation Dawn	10³ m³	0.0078	39,641	3.09	52,889	4
11	Gas Supply Commodity - System	10³ m³	0.0503	4,473	2.25	1,704	1
12	Total Rate 135				1,199		1,215
	Rate 145 Contract Service						
13	Monthly Charge	bills	$ 123.34	432	53	248	31
14	Contract Demand	10³ m³	8.23	9,242	761	9,000	741
	Delivery Charge						
15	First 14,000 m³	10³ m³	2.6095	5,143	134	2,418	63
16	Next 28,000 m³	10³ m³	1.2507	9,200	115	4,175	52
17	Over 42,000 m³	10³ m³	0.6916	35,793	248	16,868	117
18	Load Balancing	10³ m³	0.1599	50,136	80	23,645	38
19	Transportation	10³ m³	0.0236	10,692	3	776	0
20	Transportation Dawn	10³ m³	0.0078	25,167	2	22,869	2
21	Gas Supply Commodity - System	10³ m³	0.0469	8,575	4	776	0
22	Total Rate 145				1,399		1,043

EGD RATE ZONE
Calculation of 2020 and 2018 Revenue at 2018 Approved Rates

Line No.	Particulars	Billing Units (a)	Rates (cents / m^3) (b)	2018 Approved Usage (c)	2018 Revenue ($000's) (d)	2020 Actual Usage (e)	2020 Revenue ($000's) (f)
	Rate 170 Contract Service						
1	Monthly Charge	bills	$ 279.31	300	84	251	70
2	Contract Demand	10^3 m^3	4.0900	32,846	1,343	30,899	1,264
	Delivery Charge						
3	First 1,000,000 m^3	10^3 m^3	0.2793	193,825	541	170,044	475
4	Over 1,000,000 m^3	10^3 m^3	0.0793	97,328	77	77,843	62
5	Load Balancing	10^3 m^3	0.0699	291,152	204	247,886	173
6	Transportation	10^3 m^3	0.0235	42,446	10	4,843	1
7	Transportation Dawn	10^3 m^3	0.0078	171,438	13	103,703	8
8	Gas Supply Commodity - System	10^3 m^3	0.0432	34,475	15	4,843	2
9	Total Rate 170				2,287		2,055
	Rate 200 Contract Service						
10	Monthly Charge	bills		12	-	12	-
11	Contract Demand	10^3 m^3	14.7000	14,801	2,176	15,029	2,209
	Delivery Charge						
12	Per cubic metre of gas delivered	10^3 m^3	- 0.0208	169,764	(35)	189,473	(39)
13	Load Balancing	10^3 m^3	0.3097	169,764	526	189,473	587
14	Transportation	10^3 m^3	0.0235	129,627	30		-
15	Transportation Dawn	10^3 m^3	0.0078	40,137	3	50,357	4
16	Gas Supply Commodity - System	10^3 m^3	0.0432	129,627	56	139,116	60
17	Gas Supply Commodity - Buy/Sell	10^3 m^3	0.0237	-	-	-	-
18	Total Rate 200				2,756		2,821
	Rate 300 Contract Service						
19	Monthly Charge	bills	$ 500.00	12	6	22	11
20	Contract Demand	10^3 m^3	27.4365	187	51	187	51
21	Total Rate 300				57		62
	Rate 332 Transportation Service						
22	Monthly Contract Demand	$/GJ	1.2075	1,200,000	17,388	1,200,000	17,388
23	Total Rate 332				17,388		17,388
	Rate 325 Storage and Transmission						
24	Monthly Charge	bills	$ 1.00	1	1,800	1	1,800
25	Total Rate 325				1,800		1,800
26	Grand Total				1,225,109		1,257,541

UNION RATE ZONES
Calculation of 2020 and 2013 Revenue at 2013 Approved Rates

				2013		2020	
Line No.	Particulars	Billing Units	Rates (cents / m^3)	Approved Usage	Revenue ($000's)	Actual Usage	Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate 01						
1	Monthly Charge	bills	$ 21.00	3,839,732	80,634	4,291,233	90,116
2	Delivery Charge	10^3m^3	8.9074	884,421	78,779	988,417	88,043
3	Transportation	10^3m^3	0.01169	884,421	103	988,417	116
4	Storage	10^3m^3	1.7032	884,421	15,063	988,417	16,834
5	Total Rate 01				174,580		195,109
	Rate 10						
6	Monthly Charge	bills	$ 70.00	24,629	1,724	26,411	1,849
7	Delivery Charge	10^3m^3	5.5035	322,887	17,770	346,249	19,056
8	Transportation	10^3m^3	0.0048	322,887	15	346,249	17
9	Storage	10^3m^3	1.2478	322,887	4,029	346,249	4,321
10	Total Rate 10				23,539		25,242
	Rate 20						
11	Monthly Charge	bills	$ 1,000.00	748	748	667	667
	Monthly Demand Charge						
12	First 70,000 m^3	$10^3m^3/d$	27.8179	23,260	6,470	23,118	6,431
13	All over 70,000 m^3	$10^3m^3/d$	16.3583	19,701	3,223	62,589	10,239
	Commodity Charge						
14	First 852,000 m^3	10^3m^3	0.5135	331,197	1,701	298,705	1,534
15	All over 852,000 m^3	10^3m^3	0.3757	298,605	1,122	479,771	1,803
16	Transportation Account Charge	10^3m^3	$ 219.43	460	101	402	88
		10^3m^3					
17	Gas Supply Demand Charge	10^3m^3	1.6293	6,873	112	8,107	151
	Fort Frances		0.2175	-	-	-	-
	Western		0.0075	2,650	20	1,332	10
	Northern		0.0182	702	13	2,746	50
	Eastern		0.0226	3,521	79	4,029	91
	Storage (GJ's)						
18	Demand	GJ/d	9.6425	99,288	957	141,504	1,364
19	Commodity	GJ	0.1558	639,477	100	761,472	119
20	Total Rate 20				14,534		22,394.97
	Rate 25						
21	Monthly Charge	bills	$ 375.00	842	316	806	302
22	Delivery Charge	10^3m^3	2.6004	159,555	4,149	92,838	2,414
23	Transportation Account Charge	bills	$ 219.43	36	8	180	39
24	Gas Supply Transportation	10^3m^3	0.0516	42,913	22	28,260	15
25	Total Rate 25				4,495		2,770
	Rate 100						
26	Monthly Charge	bills	$ 1,500.00	226	339	144	216
27	Demand	$10^3m^3/d$	15.3415	71,975	11,042	43,760	6,713
28	Commodity	10^3m^3	0.2132	1,895,488	4,042	996,605	2,125
29	Transportation Account Charge	bills	$ 219.43	226	50	144	32
	Storage (GJ's)						
30	Demand	GJ/d	5.5595	15,600	87	-	-
31	Commodity	GJ	0.1558	100,000	16	-	-
32	Total Rate 100				15,575		9,086
33	Total Union North In-franchise				232,722		254,602

UNION RATE ZONES
Calculation of 2020 and 2013 Revenue at 2013 Approved Rates

Line No.	Particulars	Billing Units	Rates (cents / m^3)	2013 Approved Usage	2013 Revenue ($000's)	2020 Actual Usage	2020 Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate M1						
1	Monthly Charge	bills	$ 21.00	12,706,802	266,843	13,859,843	291,057
2	Delivery Commodity Charge (avg rate)	10^3m^3	3.4245	2,939,543	100,664	3,206,283	109,798
3	Storage	10^3m^3	0.7368	2,939,543	21,660	3,206,283	23,625
4	Total Rate M1				389,166		424,480
	Rate M2						
5	Monthly Charge	bills	$ 70.00	81,451	5,702	94,352	6,605
6	Delivery Commodity Charge (avg rate)	10^3m^3	3.8103	975,571	37,173	1,130,091	43,060
7	Storage		0.7550	975,571	7,366	1,130,091	8,533
8	Total Rate M2				50,240		58,198
	Rate M4						
	Monthly Demand Charge						
9	First 8 450 m^3	$10^3m^3/d$	46.6239	12,905	6,017	22,149	10,327
10	Next 19 700 m^3	$10^3m^3/d$	20.9050	7,864	1,644	21,584	4,512
11	All over 28 150 m^3	$10^3m^3/d$	17.5631	4,507	792	4,257	748
	Delivery Commodity Charge						
12	First Block	10^3m^3	0.9621	396,153	3,811	621,093	5,976
13	All remaining use	10^3m^3	0.4243	8,525	36	-	-
	Interruptible						
14	Monthly Charge	bills	$ 690.00	-	-	32	22
15	Delivery Commodity Charge (Avg Price)	10^3m^3	2.2413	-	-	132	3
16	Interruptible Delivery Charge - Days Use Discount						-1.61
17	Total Rate M4				12,300		21,586
	Rate M5A						
	Firm Contracts						
18	Monthly Demand Charge	$10^3m^3/d$	28.6252	626	179	538	154
19	Delivery Commodity Charge	10^3m^3	1.9377	17,385	337	6,098	118
	Interruptible Contracts						
20	Monthly Charge	bills	$ 690.00	1,692	1,167	454	313
21	Delivery Commodity Charge (Avg Price)	10^3m^3	2.2413	517,747	11,604	55,719	1,249
22	Total Rate M5A				13,288		1,834
	Rate M7						
	Firm Contracts						
23	Monthly Demand Charge	$10^3m^3/d$	25.3924	14,220	3,611	46,014	11,684
24	Delivery Commodity Charge	10^3m^3	0.3206	142,488	457	523,031	1,677
	Interruptible / Seasonal Contracts						
25	Delivery Commodity Charge	10^3m^3	1.2747	4,655	59	95,341	1,215
26	Total Rate M7				4,127		14,576
	Rate M9						
27	Monthly Demand Charge	$10^3m^3/d$	15.1688	3,993	606	6,040	916
28	Delivery Commodity Charge	10^3m^3	0.1990	60,750	121	88,765	177
29	Total Rate M9				727		1,093
	Rate M10						
30	Delivery Commodity Charge	10^3m^3	5.1734	189	10	360	19
31	Total Rate M10				10		19

UNION RATE ZONES
Calculation of 2020 and 2013 Revenue at 2013 Approved Rates

Line No.	Particulars	Billing Units	Rates (cents / m^3)	2013 Approved Usage	2013 Revenue ($000's)	2020 Actual Usage	2020 Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate T1						
	Storage ($/GJ's)						
	Demand						
	Firm injection / withdrawal						
1	Union provides deliverability inventory	GJ/d	1.624	492,360	800	633,912	1,029
2	Customer provides deliverability inventory	GJ/d	1.197	166,800	200	10,596	13
3	Incremental firm injection right	GJ/d	1.197	-	-	-	-
4	Interruptible	GJ/d	1.197	62,244	75	-	-
5	Space	GJ/d	0.011	22,396,680	253	16,986,769	192
6	Commodity (Customer Provides)	GJ	0.008	2,750,300	21	5,114,951	39
7	Commodity (Union Provides)	GJ	0.030	-	-	-	-
		GJ					
	Transportation (cents/m^3)						
	Demand						
8	First 28 150 m^3	$10^3m^3/d$	31.9554	12,448	3,978	14,718	4,703
9	Next 112 720 m^3	$10^3m^3/d$	22.0775	13,002	2,871	12,177	2,688
	Commodity						
10	Firm	10^3m^3	0.0712	485,700	346	395,861	282
11	Interruptible	10^3m^3	1.2341	63,286	781	34,450	425
12	Monthly Charges		$ 1,936.13	528	1,022	556	1,076
13	Total Rate T1				10,345		10,448
	Rate T2						
	Storage ($/GJ's)						
	Demand						
	Firm injection / withdrawal						
14	Union provides deliverability inventory	GJ/d	1.624	1,516,920	2,463	2,280,262	3,703
15	Customer provides deliverability inventory	GJ/d	1.197	1,336,556	1,600	870,500	1,042
16	Incremental firm injection right	GJ/d	1.197	-	-	22,800	27
17	Interruptible	GJ/d	1.197	415,704	498	180,000	215
18	Space	GJ/d	0.011	106,645,056	1,204	108,814,049	1,229
19	Commodity (Customer Provides)	GJ	0.008	7,869,782	60	30,611,595	233
20	Commodity (Union Provides)	GJ	0.030	-	-	-	-
	Transportation (cents/m^3)						
	Demand						
21	First 140 870 m^3	$10^3m^3/d$	20.191	49,971	10,090	59,066	11,926
22	All Over 140 870 m^3	$10^3m^3/d$	10.680	167,088	17,845	221,674	23,675
	Commodity						
23	Firm	10^3m^3	0.008	4,521,813	353	3,854,610	301
24	Interruptible	10^3m^3	0.945	358,485	3,387	163,365	1,543
25	Monthly Charges	Meter/mo.	$ 6,000.00	444	2,664	480	2,880
26	Total Rate T2				40,164		46,775
	Rate T3						
	Storage ($/GJ's)						
	Demand						
	Firm injection / withdrawal						
27	Union provides deliverability inventory	GJ/d	1.624	-	-	-	-
28	Customer provides deliverability inventory	GJ/d	1.197	679,320	813	649,668	778
29	Incremental firm injection right	GJ/d	1.197	-	-	-	-
30	Interruptible	GJ/d	1.197	-	-	-	-
31	Space	GJ/d	0.011	36,614,256	414	38,472,252	435
32	Commodity (Customer Provides)	GJ	0.008	4,459,672	34	4,804,181	37
33	Commodity (Union Provides)	GJ	0.030	-	-	-	-
	Transportation (cents/ m^3)						
34	Demand	$10^3m^3/d$	9.358	28,200	2,639	28,200	2,639
35	Commodity	10^3m^3	0.011	272,712	29	264,209	28
36	Monthly Charges	Meter/mo.	$ 20,371.35	12	244	12	244
37	Total Rate T3				4,173		4,160
38	Total Union South In-franchise				524,540		583,169

UNION RATE ZONES
Calculation of 2020 and 2013 Revenue at 2013 Approved Rates

				2013		2020	
Line No.	Particulars	Billing Units	Rates ($/GJ)	Approved Usage	Revenue ($000's)	Actual Usage	Revenue ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)
	Rate M12						
	Demand						
1	Dawn to Kirkwall	GJ/d	2.011	8,708,176	17,509	1,409,148	2,833
2	Dawn to Kirkwall F24-T	GJ/d	0.068	594,000	40	594,000	40
3	Dawn to Parkway	GJ/d	2.382	43,052,600	102,570	55,730,459	132,774
4	Dawn to Parkway F24-T	GJ/d	0.068	4,711,848	319	6,437,148	436
5	Kirkwall to Parkway	GJ/d	0.372	1,411,468	525	5,053,860	1,879
6	M12-X Easterly & Westerly	GJ/d	2.961	4,692,132	13,896	4,752,132	14,073
7	Total Rate M12				134,859		152,035
	Rate M13						
8	Monthly Fixed Charge	monthly	$ 926.60	15	167	4	47
9	Transmission Commodity Charge	GJ	0.034	5,934,507	200	1,805,159	61
10	Total Rate M13				367		108
	Rate M16						
11	Monthly Fixed Charge	monthly	$ 1,474.12	4	71	3	53
12	Transmission Commodity Charge	GJ	0.034	6,236,394	211	6,656,862	225
13	Monthly Demand Charge - West of Dawn	GJ/d	1.059	214,154	227	225,914	239
14	Monthly Demand Charge - East of Dawn	GJ/d	0.741	108,800	81	-	-
15	Total Rate M16				589		517
	Rate C1						
	Storage Services						
16	Peak Storage (Short-term)	GJ			7,883		2,715
17	Balancing	GJ			2,000		1,016
18	Loans	GJ					1
19	Off Peak Storage	GJ			500		1,002
	Short-term Storage and Other Balancing Services						
20	Deferral Account Balance						2,900
	Transportation Services						
	Demand						
21	Ojibway to Dawn	GJ/d	1.059	1,025,520	1,197	653,284	692
22	St. Clair to Dawn	GJ/d	1.059		2,000	-	-
23	Parkway to Dawn	GJ/d	0.579	4,331,523	2,508	6,815,588	3,946
24	Kirkwall to Dawn	GJ/d	1.021	-	-	5,860,092	5,984
25	Bluewater to Dawn	GJ/d	1.059	-	-	615,000	651
26	Dawn to Parkway	GJ/d	2.382	84,780	413	536,305	1,278
27	Dawn to Dawn-Vector	GJ/d	0.029	1,114,140	32	1,114,140	32
28	Dawn to Dawn (TCPL)	GJ/d	0.134	6,000,000	805	6,000,000	805
29	Short-term Transportation	GJ			11,067		5,698
30	Exchanges				14,918		4,244
31	Ratepayer portion Exchange Revenue				(13,426)		(3,820)
32	Other Transactional				1,067		1,195
33	Total Rate C1				30,963		28,341
34	Total Ex-Franchise				166,778		181,002
35	Grand Total				924,039		1,018,772

SUMMARY
RETURN ON RATE BASE & EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS INC.

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2020

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
			($Millions) & (%'s)
2.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	841.1
3.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	39.2
4.	**Utility Income**		**801.9**
5.	**Utility Rate Base**	(Ex. B, Tab 1, Sch. 4)	**13,562.0**
6.	Indicated Return on Rate Base %	(line 4 / line 5)	5.913%
7.	Less: Required Rate of Return %	(Ex. B, Tab 1, Sch. 5)	6.382%
8.	**(Deficiency) / Sufficiency %**		**-0.469%**
9.	Net Earnings (Deficiency) / Sufficiency	(line 5 x line 8)	(63.6)
10.	Provision for Income Taxes		(22.9)
11.	**Gross Earnings (Deficiency) / Sufficiency**	(line 9 / 73.5%)	**(86.5)**
12.	**50% Earnings sharing to ratepayers**	(if line 11 > 1, line 11 x 50%)	-
13.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
14.	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 2)	841.1
15.	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	375.3
16.	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 5)	1.0
17.	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 5)	0.0
18.	Net Income before Income Taxes		464.8
19.	Less: Income Taxes	(Ex. B, Tab 1, Sch. 3)	39.2
20.	**Net Income Applicable to Common Equity**	(line 18 - line 19)	**425.6**
21.	Common Equity	(Ex. B, Tab 1, Sch. 5)	4,882.3
22.	Approved ROE (including deadband before earning sharing) %	(Board-approved + 150bp)	10.020%
23.	Achieved Rate of Return on Equity %	(line 20 / line 21)	8.717%
24.	**Resulting (Deficiency) / Sufficiency in Return on Equity %**		**-1.303%**
25.	Net Earnings (Deficiency) / Sufficiency	(line 21 x line 24)	(63.6)
26.	Provision for Income Taxes		(22.9)
27.	**Gross Earnings (Deficiency) / Sufficiency**	**(line 25 / 73.5%)**	**(86.5)**
28.	**50% Earnings sharing to ratepayers**	(if line 27 > 1, line 27 x 50%)	-

N/A – INTENTIONALLY LEFT BLANK

EGD RATE ZONE
ICM Project Revenue Requirement
St. Laurent Ottawa North Replacement Phase 3 Project

Line No.	Particulars ($000's)	2022	2023	Average Annual (5)
		(a)	(b)	(c)
	Incremental Rate Base Investment			
1	Capital Expenditures	86,037	-	
2	Average Rate Base	6,400	84,980	
	Incremental Revenue Requirement Calculation:			
	Return on Incremental Rate Base: (1)			
3	Long-term Debt Interest	186	2,470	1,328
4	Short-term Debt Interest	1	8	4
5	Preference Shares	3	37	20
6	Equity	207	2,753	1,480
7	Total Return on Incremental Rate Base	397	5,268	2,832
	Incremental Operating Expenses:			
8	Depreciation Expense (2)	58	1,998	1,028
9	Total Incremental Operating Expenses	58	1,998	1,028
	Incremental Income Taxes:			
10	Return on Equity and Preference Shares (line 5 + line 6)	210	2,790	1,500
	Utility Timing Differences			
11	Add: Depreciation Expense (line 8)	58	1,998	1,028
12	Less: Current Year Tax Deductions	(14,271)	(4,306)	(9,289)
13	Taxable Income (line 10 + line 11 + line 12)	(14,003)	482	(6,760)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(3,711)	128	(1,792)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(5,049)	174	(2,437)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(4,594)	7,440	1,423

Notes:

(1) The return on rate base is calculated based on EGD's 2018 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.84%	4.70%	2.91%
Short-term Debt	0.56%	1.60%	0.01%
Preference Shares	1.60%	2.72%	0.04%
Equity	36.00%	9.00%	3.24%
Total	100.00%		6.20%

(2) Depreciation expense at Board-approved depreciation rates.

(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.

(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(5) Average annual revenue requirement calculated as the total revenue requirement from 2022 to 2023 recovered over the 24-month period from January 1, 2022 to December 31, 2023 expressed as an annual amount (12 months).

EGD RATE ZONE
ICM Project Revenue Requirement
NPS 20 Replacement Cherry to Bathurst Project

Line No.	Particulars ($000's)	2022	2023	Average Annual (5)
		(a)	(b)	(c)
	Incremental Rate Base Investment			
1	Capital Expenditures	126,730	-	
2	Average Rate Base	26,359	124,682	
	Incremental Revenue Requirement Calculation:			
	Return on Incremental Rate Base: (1)			
3	Long-term Debt Interest	766	3,624	2,195
4	Short-term Debt Interest	2	11	7
5	Preference Shares	11	54	33
6	Equity	854	4,040	2,447
7	Total Return on Incremental Rate Base	1,634	7,729	4,682
	Incremental Operating Expenses:			
8	Depreciation Expense (2)	512	3,072	1,792
9	Total Incremental Operating Expenses	512	3,072	1,792
	Incremental Income Taxes:			
10	Return on Equity and Preference Shares (line 5 + line 6)	866	4,094	2,480
	Utility Timing Differences			
11	Add: Depreciation Expense (line 8)	512	3,072	1,792
12	Less: Current Year Tax Deductions	(21,066)	(6,329)	(13,697)
13	Taxable Income (line 10 + line 11 + line 12)	(19,688)	837	(9,426)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(5,217)	222	(2,498)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(7,098)	302	(3,398)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(4,953)	11,102	3,075

Notes:

(1) The return on rate base is calculated based on EGD's 2018 Board-approved capital structure:

Capital Structure	Component %	Cost Rate	Return Component
Long-term Debt	61.84%	4.70%	2.91%
Short-term Debt	0.56%	1.60%	0.01%
Preference Shares	1.60%	2.72%	0.04%
Equity	36.00%	9.00%	3.24%
Total	100.00%		6.20%

(2) Depreciation expense at Board-approved depreciation rates.
(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.
(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(5) Average annual revenue requirement calculated as the total revenue requirement from 2022 to 2023 recovered over the 24-month period from January 1, 2022 to December 31, 2023 expressed as an annual amount (12 months).

UNION RATE ZONES
ICM Project Revenue Requirement
Dawn to Cuthbert Replacement and Retrofits Project

Line No.	Particulars ($000's)	2022 (a)	2023 (b)	Average Annual (5) (c)
	Incremental Rate Base Investment			
1	Capital Expenditures	23,508	-	
2	Average Rate Base	6,841	23,135	
	Incremental Revenue Requirement Calculation:			
	Return on Incremental Rate Base: (1)			
3	Long-term Debt Interest	274	926	600
4	Short-term Debt Interest	(0)	(0)	(0)
5	Preference Shares	6	19	13
6	Equity	220	744	482
7	Total Return on Incremental Rate Base	499	1,689	1,094
	Incremental Operating Expenses:			
8	Depreciation Expense (2)	124	497	311
9	Total Incremental Operating Expenses	124	497	311
	Incremental Income Taxes:			
10	Return on Equity and Preference Shares (line 5 + line 6)	226	763	494
	Utility Timing Differences			
11	Add: Depreciation Expense (line 8)	124	497	311
12	Less: Current Year Tax Deductions	(4,949)	(1,711)	(3,330)
13	Taxable Income (line 10 + line 11 + line 12)	(4,599)	(450)	(2,525)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(1,219)	(119)	(669)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(1,658)	(162)	(910)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(1,034)	2,024	495

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate
Long-term Debt	61.30%	6.53%
Short-term Debt	-0.03%	1.31%
Preference Shares	2.74%	3.05%
Equity	36.00%	8.93%
Total	100.00%	

(2) Depreciation expense at Board-approved depreciation rates.

(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.

(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(5) Average annual revenue requirement calculated as the total revenue requirement from 2022 to 2023 recovered over the 24-month period from January 1, 2022 to December 31, 2023 expressed as an annual amount (12 months).

UNION RATE ZONES
ICM Project Revenue Requirement
Byron Transmission Station Project

Line No.	Particulars ($000's)	2022 (a)	2023 (b)	Average Annual (5) (c)
	Incremental Rate Base Investment			
1	Capital Expenditures	20,381	-	
2	Average Rate Base	5,928	19,989	
	Incremental Revenue Requirement Calculation:			
	Return on Incremental Rate Base: (1)			
3	Long-term Debt Interest	237	800	519
4	Short-term Debt Interest	(0)	(0)	(0)
5	Preference Shares	5	17	11
6	Equity	191	643	417
7	Total Return on Incremental Rate Base	433	1,459	946
	Incremental Operating Expenses:			
8	Depreciation Expense (2)	130	522	326
9	Total Incremental Operating Expenses	130	522	326
	Incremental Income Taxes:			
10	Return on Equity and Preference Shares (line 5 + line 6)	196	659	427
	Utility Timing Differences			
11	Add: Depreciation Expense (line 8)	130	522	326
12	Less: Current Year Tax Deductions	(7,146)	(2,591)	(4,868)
13	Taxable Income (line 10 + line 11 + line 12)	(6,820)	(1,409)	(4,115)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(1,807)	(373)	(1,090)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(2,459)	(508)	(1,484)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(1,896)	1,473	(211)

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate
Long-term Debt	61.30%	6.53%
Short-term Debt	-0.03%	1.31%
Preference Shares	2.74%	3.05%
Equity	36.00%	8.93%
Total	100.00%	

(2) Depreciation expense at Board-approved depreciation rates.

(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.

(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(5) Average annual revenue requirement calculated as the total revenue requirement from 2022 to 2023 recovered over the 24-month period from January 1, 2022 to December 31, 2023 expressed as an annual amount (12 months).

UNION RATE ZONES
ICM Project Revenue Requirement
Kirkland Lake Lateral Replacement Project

Line No.	Particulars ($000's)	2022	2023	Average Annual (5)
		(a)	(b)	(c)
	Incremental Rate Base Investment			
1	Capital Expenditures	20,666	-	
2	Average Rate Base	2,581	20,302	
	Incremental Revenue Requirement Calculation:			
	Return on Incremental Rate Base: (1)			
3	Long-term Debt Interest	103	813	458
4	Short-term Debt Interest	(0)	(0)	(0)
5	Preference Shares	2	17	10
6	Equity	83	653	368
7	Total Return on Incremental Rate Base	188	1,482	835
	Incremental Operating Expenses:			
8	Depreciation Expense (2)	52	624	338
9	Total Incremental Operating Expenses	52	624	338
	Incremental Income Taxes:			
10	Return on Equity and Preference Shares (line 5 + line 6)	85	670	377
	Utility Timing Differences			
11	Add: Depreciation Expense (line 8)	52	624	338
12	Less: Current Year Tax Deductions	(3,399)	(1,036)	(2,218)
13	Taxable Income (line 10 + line 11 + line 12)	(3,262)	258	(1,502)
14	Income Taxes Before Gross Up (line 13 x 26.5%) (3)	(864)	68	(398)
15	Total Incremental Income Taxes After Gross Up (line 14 / (1-26.5%) (3) (4)	(1,176)	93	(542)
16	Total Incremental Revenue Requirement (line 7 + line 9 + line 15)	(936)	2,199	632

Notes:

(1) The return on rate base is calculated based on Union's 2013 Board-approved capital structure:

Capital Structure	Component %	Cost Rate
Long-term Debt	61.30%	6.53%
Short-term Debt	-0.03%	1.31%
Preference Shares	2.74%	3.05%
Equity	36.00%	8.93%
Total	100.00%	

(2) Depreciation expense at Board-approved depreciation rates.
(3) Enbridge Gas's current provincial and federal tax rate is equal to 26.5%.
(4) Incremental taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(5) Average annual revenue requirement calculated as the total revenue requirement from 2022 to 2023 recovered over the 24-month period from January 1, 2022 to December 31, 2023 expressed as an annual amount (12 months).

EGD RATE ZONE
Allocation of 2022 ICM Project Revenue Requirement

		St. Laurent Ottawa North Replacement Phase 3 Project		NPS 20 Replacement Cherry to Bathurst Project		
Line No.	Particulars	Delivery Demand LP Allocator (1) (%)	Project 2022 ICM Allocation (2) (000's)	Delivery Demand HP Allocator (3) (%)	Project 2022 ICM Allocation (4) (000's)	Total 2022 ICM Allocation (000's)
		(a)	(b)	(c)	(d)	(e)
1	Rate 1	53%	749	52%	1,612	2,361
2	Rate 6	43%	610	43%	1,312	1,921
3	Rate 9	0%	-	0%	-	-
4	Rate 100	0%	2	0%	4	6
5	Rate 110	4%	52	4%	112	165
6	Rate 115	1%	8	1%	31	40
7	Rate 125	0%	-	0%	-	-
8	Rate 135	0%	0	0%	0	0
9	Rate 145	0%	1	0%	1	2
10	Rate 170	0%	1	0%	2	4
11	Rate 200	0%	-	0%	-	-
12	Rate 300	0%	0	0%	0	0
13	Total	100%	1,423	100%	3,075	4,498

Notes:
(1) St. Laurent Ottawa North Replacement Phase 3 project replaces the current extra high pressure steel mains with three segments of low pressure plastic mains. Low pressure mains are allocated according to the Board approved cost allocation methodology (EB-2017-0086), Delivery Demand LP allocator, reflecting 2022 forecast peak demand by rate class.
(2) Exhibit B, Tab 2, Schedule 1, Appendix E, Page 1.
(3) NPS 20 Replacement Cherry to Bathrust project replaces approximately 4.5km of NPS 20 inch high pressure steel main on Lake Shore Boulevard from Cherry Street to Bathrust Street. High pressure mains are allocated according to the Board approved cost allocation methodology (EB-2017-0086), Delivery Demand HP allocator, reflecting 2022 forecast peak demand by rate class.
(4) Exhibit B, Tab 2, Schedule 1, Appendix E, Page 2.

UNION RATE ZONES
Allocation of 2022 ICM Project Revenue Requirement

Line No.	Particulars	Dawn to Cuthbert Replacement and Retrofits Project: Dawn-Parkway Easterly Demand Allocator (1) ($10^6 m^3/d$ x km)	Dawn to Cuthbert Replacement and Retrofits Project: Project 2022 ICM Allocation (2) ($000's)	Byron Transmission Station Project: Other Transmission Demand Allocator (3) ($10^3 m^3/d$)	Byron Transmission Station Project: Project 2022 ICM Allocation (4) ($000's)	Kirkland Lake Lateral Replacement Project: Union North Joint Use Mains Allocator (5) (%)	Kirkland Lake Lateral Replacement Project: Project 2022 ICM Allocation (6) ($000's)	Total 2022 ICM Allocation ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (b+d+f)
1	Rate 01	1,702	21	-	-	37	231	252
2	Rate 10	516	6	-	-	12	78	84
3	Rate 20	163	2	-	-	27	168	170
4	Rate 25	-	-	-	-	3	20	20
5	Rate 100	-	-	-	-	21	135	135
6	Total Union North	2,381	30	-	-	100	632	662
7	Rate M1	3,358	42	31,237	(79)	-	-	(37)
8	Rate M2	1,250	16	11,628	(29)	-	-	(14)
9	Rate M4 (F)	268	3	4,190	(11)	-	-	(7)
10	Rate M4 (I)	-	-	-	-	-	-	-
11	Rate M5 (F)	1	0	37	(0)	-	-	(0)
12	Rate M5 (I)	-	-	-	-	-	-	-
13	Rate M7 (F)	212	3	5,225	(13)	-	-	(11)
14	Rate M7 (I)	-	-	-	-	-	-	-
15	Rate M9	69	1	502	(1)	-	-	(0)
16	Rate M10	1	0	5	(0)	-	-	(0)
17	Rate T1 (F)	172	2	1,922	(5)	-	-	(3)
18	Rate T1 (I)	-	-	-	-	-	-	-
19	Rate T2 (F)	1,085	14	26,233	(66)	-	-	(53)
20	Rate T2 (I)	-	-	-	-	-	-	-
21	Rate T3	345	4	2,512	(6)	-	-	(2)
22	Total Union South	6,762	84	83,489	(211)	-	-	(127)
23	Excess Utility Storage	-	-	-	-	-	-	-
24	Rate C1 (F)	194	2	-	-	-	-	2
25	Rate C1 (I)	-	-	-	-	-	-	-
26	Rate M12	30,230	378	-	-	-	-	378
27	Rate M13	-	-	-	-	-	-	-
28	Rate M16	-	-	-	-	-	-	-
29	Rate M17	36	0	-	-	-	-	0
30	Total Ex-Franchise	30,460	381	-	-	-	-	381
31	Total Union Rate Zones	39,603	495	83,489	(211)	100	632	915

Notes:
(1) Dawn-Parkway easterly demand allocation in proportion to forecast 2022 distance-weighted Dawn-Parkway transmission design day demands (commodity kilometres).
(2) Allocated in proportion to column (a).
(3) Other transmission demand allocation in proportion to forecast 2022 Union South in-franchise firm design day demands.
(4) Allocated in proportion to column (c).
(5) Union North joint use mains allocation in proportion to system peak and average day demand excluding customers who are entirely sole use.
(6) Allocated in proportion to column (e).

EGD RATE ZONE

Deriviation of 2022 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement (1) (000's)	2022 Forecast Volumes	Billing Units	ICM Unit Rates (cents / m³)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Bundled Services				
1	Rate 1	2,361	5,104,272	10^3m^3	0.0462
2	Rate 6	1,921	4,724,179	10^3m^3	0.0407
3	Rate 9	-	-	10^3m^3	-
4	Rate 100	6	4,051	$10^3m^3/d$	0.1438
5	Rate 110	165	74,003	$10^3m^3/d$	0.2225
6	Rate 115	40	13,773	$10^3m^3/d$	0.2880
7	Rate 135	0	55,553	10^3m^3	0.0002
8	Rate 145	2	6,541	$10^3m^3/d$	0.0243
9	Rate 170	4	27,557	$10^3m^3/d$	0.0133
10	Rate 200	-	14,324	$10^3m^3/d$	-
	Unbundled Services				
11	Rate 125	-	111,124	$10^3m^3/d$	-
12	Rate 300	0.2	47	$10^3m^3/d$	0.3584
13	Total EGD Rate Zone	4,498			

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix F, Page 1.

UNION RATE ZONES
Derivation of 2022 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement (1) ($000s)	2022 Forecast Usage	Billing Units	2022 ICM Rate (2) (cents / m^3)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Union North				
	Rate 01 General Service				
1	Monthly Delivery Charge	252	1,025,730	10^3m^3	0.0246
	Rate 10 General Service				
2	Monthly Delivery Charge	84	367,857	10^3m^3	0.0229
	Rate 20 Medium Volume Firm Service				
3	Delivery Demand Charge	170	83,824	$10^3m^3/d$	0.2033
	Rate 25 Large Volume Interruptible Service				
4	Monthly Delivery Charge	20	95,235	10^3m^3	0.0206
	Rate 100 Large Volume Firm Service				
5	Delivery Demand Charge	135	45,469	$10^3m^3/d$	0.2968
6	Total Union North In-Franchise	662			

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix F, p. 2, column (g).
(2) To be included in delivery and transportation rates.

UNION RATE ZONES

Derivation of 2022 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement (1) ($000s)	2022 Forecast Usage	Billing Units	2022 ICM Rate (2) (cents / m³)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Union South				
	Rate M1 Small Volume General Service				
1	Monthly Delivery Commodity Charge	(37)	3,134,770	10³m³	(0.0012)
	Rate M2 Large Volume General Service				
2	Monthly Delivery Commodity Charge	(14)	1,290,856	10³m³	(0.0011)
	Rate M4 Firm Commercial/Industrial Contract Rate				
	Firm Contracts				
3	Monthly Demand Charge	(7)	46,823	10³m³/d	(0.0155)
	Interruptible Contracts				
	Monthly Delivery Commodity Charge	-	2,275	10³m³	-
	Rate M5A Interruptible Commercial/Industrial Contract Rate				
	Firm Contracts				
4	Monthly Demand Charge	(0)	444	10³m³/d	(0.0174)
	Interruptible Contracts				
	Delivery Commodity Charge (Avg Price)	-	59,781	10³m³	-
	Rate M7 Special Large Volume Contract Rate				
	Firm Contracts				
5	Monthly Demand Charge	(11)	59,760	10³m³/d	(0.0177)
	Interruptible / Seasonal Contracts				
	Monthly Delivery Commodity Charge	-	93,732	10³m³	-
	Rate M9 Large Wholesale Service				
6	Monthly Demand Charge	(0)	6,040	10³m³/d	(0.0068)
	Rate M10 Small Wholesale Service				
7	Monthly Delivery Commodity Charge	(0)	360	10³m³	(0.0011)
	Rate T1 Contract Carriage Service				
	Firm Contracts				
8	Monthly Demand Charge	(3)	26,075	10³m³/d	(0.0104)
	Interruptible Contracts				
	Interruptible Transportation Commodity Charge	-	34,865	10³m³	-
	Rate T2 Contract Carriage Service				
	Firm Contracts				
9	Monthly Demand Charge	(53)	296,408	10³m³/d	(0.0178)
	Interruptible Contracts				
	Interruptible Transportation Commodity Charge	-	178,978	10³m³	-
	Rate T3 Contract Carriage Service				
10	Monthly Demand Charge	(2)	28,200	10³m³/d	(0.0072)
11	Total Union South In-franchise	(127)			
12	Total Union In-franchise	535			

Notes:

(1) Exhibit B, Tab 2, Schedule 1, Appendix F, p. 2, column (g).

(2) To be included in delivery and transportation rates.

UNION RATE ZONES
Derivation of 2022 Incremental Capital Module ("ICM") Rates by Rate Class

Line No.	Particulars	ICM Revenue Requirement (1) ($000s)	2022 Forecast Usage	Billing Units	2022 ICM Rate (2) (cents / m³)
		(a)	(b)	(c)	(d)
	Ex-franchise				
	Rate M12/C1 Transportation Service				
1	Dawn to Parkway Demand Charge	312	57,238,670	GJ/d	0.005
2	Dawn to Kirkwall Demand Charge	6	1,409,148	GJ/d	0.005
3	Kirkwall to Parkway Demand Charge	5	5,053,860	GJ/d	0.001
4	M12-X Demand Charge	29	4,238,868	GJ/d	0.007
5	Parkway to Kirkwall/Dawn Demand Charge	10	6,707,088	GJ/d	0.001
6	Kirkwall to Dawn Demand Charge	18	5,544,072	GJ/d	0.003
	Rate M17 Transportation Service				
7	Dawn to Delivery Area Demand Charge	0	106,356	GJ/d	0.004
8	Total Ex-franchise	381			
9	Total Union Rate Zones	915			

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix F, p. 2, column (g).
(2) To be included in delivery and transportation rates.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				**Heating, Water Htg. & Other Uses**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	249.96	249.96	0.00	0.0%	249.96	249.96	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	268.73	267.31	1.42	0.5%	405.23	403.06	2.17	0.5%
1.4	LOAD BALANCING	§ $	165.65	165.65	0.00	0.0%	253.61	253.61	0.00	0.0%
1.5	SALES COMMDTY	$	457.22	457.22	0.00	0.0%	700.00	700.00	0.00	0.0%
1.6	TOTAL SALES	$	1,141.55	1,140.13	1.42	0.1%	1,608.80	1,606.63	2.17	0.1%
1.7	TOTAL T-SERVICE	$	684.33	682.92	1.42	0.2%	908.80	906.63	2.17	0.2%
1.8	SALES UNIT RATE	$/m³	0.3726	0.3721	0.0005	0.1%	0.3430	0.3425	0.0005	0.1%
1.9	T-SERVICE UNIT RATE	$/m³	0.2233	0.2229	0.0005	0.2%	0.1937	0.1933	0.0005	0.2%
1.10	SALES UNIT RATE	$/GJ	9.6696	9.6576	0.0120	0.1%	8.9010	8.8890	0.0120	0.1%
1.11	T-SERVICE UNIT RATE	$/GJ	5.7967	5.7847	0.0120	0.2%	5.0281	5.0161	0.0120	0.2%
			Heating Only				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	249.96	249.96	0.00	0.0%	249.96	249.96	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	172.34	171.44	0.90	0.5%	179.30	178.37	0.93	0.5%
2.4	LOAD BALANCING	§ $	105.69	105.69	0.00	0.0%	108.39	108.39	0.00	0.0%
2.5	SALES COMMDTY	$	291.73	291.73	0.00	0.0%	299.19	299.19	0.00	0.0%
2.6	TOTAL SALES	$	819.72	818.82	0.90	0.1%	836.84	835.91	0.93	0.1%
2.7	TOTAL T-SERVICE	$	527.99	527.09	0.90	0.2%	537.65	536.72	0.93	0.2%
2.8	SALES UNIT RATE	$/m³	0.4193	0.4188	0.0005	0.1%	0.4174	0.4169	0.0005	0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.2701	0.2696	0.0005	0.2%	0.2682	0.2677	0.0005	0.2%
2.10	SALES UNIT RATE	$/GJ	10.8823	10.8703	0.0120	0.1%	10.8325	10.8205	0.0120	0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	7.0094	6.9974	0.0120	0.2%	6.9596	6.9476	0.0120	0.2%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	249.96	249.96	0.00	0.0%	249.96	249.96	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	435.81	433.48	2.33	0.5%	101.13	100.63	0.50	0.5%
3.4	LOAD BALANCING	§ $	272.91	272.91	0.00	0.0%	58.44	58.44	0.00	0.0%
3.5	SALES COMMDTY	$	753.27	753.27	0.00	0.0%	161.31	161.31	0.00	0.0%
3.6	TOTAL SALES	$	1,711.95	1,709.62	2.33	0.1%	570.84	570.34	0.50	0.1%
3.7	TOTAL T-SERVICE	$	958.68	956.34	2.33	0.2%	409.53	409.03	0.50	0.1%
3.8	SALES UNIT RATE	$/m³	0.3391	0.3387	0.0005	0.1%	0.5281	0.5276	0.0005	0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1899	0.1894	0.0005	0.2%	0.3788	0.3784	0.0005	0.1%
3.10	SALES UNIT RATE	$/GJ	8.8018	8.7898	0.0120	0.1%	13.7054	13.6934	0.0120	0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	4.9289	4.9169	0.0120	0.2%	9.8325	9.8205	0.0120	0.1%
			Heating & Water Htg.				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
2.2	CUSTOMER CHG.	$	249.96	249.96	0.00	0.0%	249.96	249.96	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	219.39	218.24	1.15	0.5%	212.36	211.25	1.11	0.5%
2.4	LOAD BALANCING	§ $	134.07	134.07	0.00	0.0%	129.75	129.75	0.00	0.0%
2.5	SALES COMMDTY	$	370.07	370.07	0.00	0.0%	358.13	358.13	0.00	0.0%
2.6	TOTAL SALES	$	973.49	972.35	1.15	0.1%	950.21	949.10	1.11	0.1%
2.7	TOTAL T-SERVICE	$	603.42	602.27	1.15	0.2%	592.07	590.96	1.11	0.2%
2.8	SALES UNIT RATE	$/m³	0.3925	0.3921	0.0005	0.1%	0.3959	0.3955	0.0005	0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.2433	0.2429	0.0005	0.2%	0.2467	0.2462	0.0005	0.2%
2.10	SALES UNIT RATE	$/GJ	10.1878	10.1758	0.0120	0.1%	10.2756	10.2636	0.0120	0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	6.3149	6.3029	0.0120	0.2%	6.4027	6.3907	0.0120	0.2%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	874.68	874.68	0.00	0.0%	874.68	874.68	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,609.73	1,600.53	9.19	0.6%	2,065.56	2,053.65	11.91	0.6%
1.4	LOAD BALANCING	§ $	1,202.93	1,202.93	0.00	0.0%	1,557.96	1,557.96	0.00	0.0%
1.5	SALES COMMDTY	$	3,378.33	3,378.33	0.00	0.0%	4,375.42	4,375.42	0.00	0.0%
1.6	TOTAL SALES	$	7,065.67	7,056.47	9.19	0.1%	8,873.62	8,861.72	11.91	0.1%
1.7	TOTAL T-SERVICE	$	3,687.34	3,678.14	9.19	0.2%	4,498.20	4,486.29	11.91	0.3%
1.8	SALES UNIT RATE	$/m³	0.3126	0.3122	0.0004	0.1%	0.3031	0.3027	0.0004	0.1%
1.9	T-SERVICE UNIT RATE	$/m³	0.1631	0.1627	0.0004	0.2%	0.1536	0.1532	0.0004	0.3%
1.10	SALES UNIT RATE	$/GJ	8.1120	8.1015	0.0106	0.1%	7.8661	7.8556	0.0106	0.1%
1.11	T-SERVICE UNIT RATE	$/GJ	4.2334	4.2229	0.0106	0.2%	3.9875	3.9769	0.0106	0.3%
			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	**(B)**			**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	874.68	874.68	0.00	0.0%	874.68	874.68	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	8,701.47	8,632.50	68.96	0.8%	15,951.37	15,813.45	137.93	0.9%
2.4	LOAD BALANCING	§ $	9,022.92	9,022.92	0.00	0.0%	18,045.78	18,045.78	0.00	0.0%
2.5	SALES COMMDTY	$	25,340.19	25,340.19	0.00	0.0%	50,680.23	50,680.23	0.00	0.0%
2.6	TOTAL SALES	$	43,939.25	43,870.29	68.96	0.2%	85,552.06	85,414.14	137.93	0.2%
2.7	TOTAL T-SERVICE	$	18,599.06	18,530.10	68.96	0.4%	34,871.83	34,733.91	137.93	0.4%
2.8	SALES UNIT RATE	$/m³	0.2591	0.2587	0.0004	0.2%	0.2523	0.2519	0.0004	0.2%
2.9	T-SERVICE UNIT RATE	$/m³	0.1097	0.1093	0.0004	0.4%	0.1028	0.1024	0.0004	0.4%
2.10	SALES UNIT RATE	$/GJ	6.7255	6.7149	0.0106	0.2%	6.5474	6.5369	0.0106	0.2%
2.11	T-SERVICE UNIT RATE	$/GJ	2.8468	2.8363	0.0106	0.4%	2.6688	2.6582	0.0106	0.4%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	874.68	874.68	0.00	0.0%	874.68	874.68	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,856.00	2,838.40	17.60	0.6%	3,834.47	3,808.48	25.99	0.7%
3.4	LOAD BALANCING	§ $	2,303.31	2,303.31	0.00	0.0%	3,400.46	3,400.46	0.00	0.0%
3.5	SALES COMMDTY	$	6,468.69	6,468.69	0.00	0.0%	9,549.93	9,549.93	0.00	0.0%
3.6	TOTAL SALES	$	12,502.69	12,485.08	17.60	0.1%	17,659.53	17,633.54	25.99	0.1%
3.7	TOTAL T-SERVICE	$	6,034.00	6,016.39	17.60	0.3%	8,109.61	8,083.62	25.99	0.3%
3.8	SALES UNIT RATE	$/m³	0.2888	0.2884	0.0004	0.1%	0.2763	0.2759	0.0004	0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1394	0.1390	0.0004	0.3%	0.1269	0.1265	0.0004	0.3%
3.10	SALES UNIT RATE	$/GJ	7.4966	7.4861	0.0106	0.1%	7.1723	7.1618	0.0106	0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	3.6180	3.6074	0.0106	0.3%	3.2937	3.2831	0.0106	0.3%
			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	874.68	874.68	0.00	0.0%	874.68	874.68	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	8,907.94	8,838.97	68.96	0.8%	16,105.00	15,967.07	137.93	0.9%
4.4	LOAD BALANCING	§ $	9,022.92	9,022.92	0.00	0.0%	18,045.73	18,045.73	0.00	0.0%
4.5	SALES COMMDTY	$	25,340.19	25,340.19	0.00	0.0%	50,680.08	50,680.08	0.00	0.0%
4.6	TOTAL SALES	$	44,145.72	44,076.76	68.96	0.2%	85,705.48	85,567.56	137.93	0.2%
4.7	TOTAL T-SERVICE	$	18,805.54	18,736.57	68.96	0.4%	35,025.41	34,887.48	137.93	0.4%
4.8	SALES UNIT RATE	$/m³	0.2603	0.2599	0.0004	0.2%	0.2527	0.2523	0.0004	0.2%
4.9	T-SERVICE UNIT RATE	$/m³	0.1109	0.1105	0.0004	0.4%	0.1033	0.1029	0.0004	0.4%
4.10	SALES UNIT RATE	$/GJ	6.7571	6.7465	0.0106	0.2%	6.5592	6.5486	0.0106	0.2%
4.11	T-SERVICE UNIT RATE	$/GJ	2.8784	2.8679	0.0106	0.4%	2.6806	2.6700	0.0106	0.4%

§ The Load Balancing Charge is included in the Delivery Charge in the applicable rate Schedule.

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,524.60	1,524.60	0.00	0.0%	1,524.60	1,524.60	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	14,172.33	14,120.69	51.64	0.4%	69,013.15	68,754.36	258.79	0.4%
1.4	LOAD BALANCING	$	18,049.13	18,049.13	0.00	0.0%	31,851.41	31,851.41	0.00	0.0%
1.5	SALES COMMDTY	$	50,689.64	50,689.64	0.00	0.0%	89,452.30	89,452.30	0.00	0.0%
1.6	TOTAL SALES	$	84,435.71	84,384.07	51.64	0.1%	191,841.47	191,582.68	258.79	0.1%
1.7	TOTAL T-SERVICE	$	33,746.06	33,694.43	51.64	0.2%	102,389.17	102,130.37	258.79	0.3%
1.8	SALES UNIT RATE	$/m³	0.2489	0.2488	0.0002	0.1%	0.3205	0.3201	0.0004	0.1%
1.9	T-SERVICE UNIT RATE	$/m³	0.0995	0.0993	0.0002	0.2%	0.1711	0.1706	0.0004	0.3%
1.10	SALES UNIT RATE	$/GJ	6.4608	6.4569	0.0040	0.1%	8.3182	8.3070	0.0112	0.1%
1.11	T-SERVICE UNIT RATE	$/GJ	2.5822	2.5782	0.0040	0.2%	4.4396	4.4284	0.0112	0.3%

Rate 100 - Large Industrial Firm

			(A)	**(B)**	**CHANGE**	
					(A) - (B)	%
2.1	VOLUME	m³	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,524.60	1,524.60	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	138,580.21	138,062.63	517.58	0.4%
2.4	LOAD BALANCING	$	79,819.16	79,819.16	0.00	0.0%
2.5	SALES COMMDTY	$	224,166.14	224,166.14	0.00	0.0%
2.6	TOTAL SALES	$	444,090.11	443,572.53	517.58	0.1%
2.7	TOTAL T-SERVICE	$	219,923.98	219,406.39	517.58	0.2%
2.8	SALES UNIT RATE	$/m³	0.2961	0.2957	0.0003	0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.1466	0.1463	0.0003	0.2%
2.10	SALES UNIT RATE	$/GJ	7.6839	7.6749	0.0090	0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	3.8052	3.7963	0.0090	0.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				Rate 145 - Average Commercial Interr.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,541.28	1,541.28	0.00	0.0%	1,541.28	1,541.28	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	18,806.35	18,797.61	8.74	0.0%	30,063.64	30,050.53	13.10	0.0%
3.4	LOAD BALANCING	$	14,082.04	14,082.04	0.00	0.0%	24,851.22	24,851.22	0.00	0.0%
3.5	SALES COMMDTY	$	50,504.21	50,504.21	0.00	0.0%	89,125.22	89,125.22	0.00	0.0%
3.6	TOTAL SALES	$	84,933.89	84,925.15	8.74	0.0%	145,581.36	145,568.26	13.10	0.0%
3.7	TOTAL T-SERVICE	$	34,429.67	34,420.94	8.74	0.0%	56,456.14	56,443.04	13.10	0.0%
3.8	SALES UNIT RATE	$/m³	0.2504	0.2504	0.0000	0.0%	0.2432	0.2432	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1015	0.1015	0.0000	0.0%	0.0943	0.0943	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	6.4989	6.4983	0.0007	0.0%	6.3124	6.3118	0.0006	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	2.6345	2.6338	0.0007	0.0%	2.4479	2.4474	0.0006	0.0%
			Rate 145 - Small Industrial Interr.				Rate 145 - Average Industrial Interr.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,541.28	1,541.28	0.00	0.0%	1,541.28	1,541.28	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	19,082.23	19,073.49	8.74	0.0%	30,307.85	30,294.74	13.10	0.0%
4.4	LOAD BALANCING	$	14,082.04	14,082.04	0.00	0.0%	24,851.18	24,851.18	0.00	0.0%
4.5	SALES COMMDTY	$	50,504.21	50,504.21	0.00	0.0%	89,125.07	89,125.07	0.00	0.0%
4.6	TOTAL SALES	$	85,209.77	85,201.03	8.74	0.0%	145,825.38	145,812.27	13.10	0.0%
4.7	TOTAL T-SERVICE	$	34,705.55	34,696.82	8.74	0.0%	56,700.30	56,687.20	13.10	0.0%
4.8	SALES UNIT RATE	$/m³	0.2512	0.2512	0.0000	0.0%	0.2436	0.2436	0.0000	0.0%
4.9	T-SERVICE UNIT RATE	$/m³	0.1023	0.1023	0.0000	0.0%	0.0947	0.0947	0.0000	0.0%
4.10	SALES UNIT RATE	$/GJ	6.5200	6.5194	0.0007	0.0%	6.3230	6.3224	0.0006	0.0%
4.11	T-SERVICE UNIT RATE	$/GJ	2.6556	2.6549	0.0007	0.0%	2.4585	2.4580	0.0006	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,339.92	7,339.92	0.00	0.0%	7,339.92	7,339.92	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	14,982.37	14,894.49	87.88	0.6%	245,716.53	244,278.37	1,438.16	0.6%
5.4	LOAD BALANCING	$	26,317.98	26,317.98	0.00	0.0%	438,632.42	438,632.42	0.00	0.0%
5.5	SALES COMMDTY	$	89,102.78	89,102.78	0.00	0.0%	1,485,044.45	1,485,044.45	0.00	0.0%
5.6	TOTAL SALES	$	137,743.04	137,655.16	87.88	0.1%	2,176,733.31	2,175,295.16	1,438.16	0.1%
5.7	TOTAL T-SERVICE	$	48,640.27	48,552.38	87.88	0.2%	691,688.87	690,250.71	1,438.16	0.2%
5.8	SALES UNIT RATE	$/m³	0.2301	0.2300	0.0001	0.1%	0.2182	0.2181	0.0001	0.1%
5.9	T-SERVICE UNIT RATE	$/m³	0.0813	0.0811	0.0001	0.2%	0.0693	0.0692	0.0001	0.2%
5.10	SALES UNIT RATE	$/GJ	5.9725	5.9687	0.0038	0.1%	5.6630	5.6592	0.0037	0.1%
5.11	T-SERVICE UNIT RATE	$/GJ	2.1090	2.1052	0.0038	0.2%	1.7995	1.7958	0.0037	0.2%
			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,339.92	7,339.92	0.00	0.0%	7,780.32	7,780.32	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	196,096.6	195,124.50	972.09	0.5%	1,045,081.5	1,036,823.99	8,257.51	0.8%
6.4	LOAD BALANCING	$	438,632.37	438,632.37	0.00	0.0%	2,965,216.40	2,965,216.40	0.00	0.0%
6.5	SALES COMMDTY	$	1,485,044.30	1,485,044.30	0.00	0.0%	10,395,311.57	10,395,311.57	0.00	0.0%
6.6	TOTAL SALES	$	2,127,113.18	2,126,141.09	972.09	0.0%	14,413,389.79	14,405,132.28	8,257.51	0.1%
6.7	TOTAL T-SERVICE	$	642,068.88	641,096.79	972.09	0.2%	4,018,078.22	4,009,820.71	8,257.51	0.2%
6.8	SALES UNIT RATE	$/m³	0.2132	0.2131	0.0001	0.0%	0.2064	0.2063	0.0001	0.1%
6.9	T-SERVICE UNIT RATE	$/m³	0.0644	0.0643	0.0001	0.2%	0.0575	0.0574	0.0001	0.2%
6.10	SALES UNIT RATE	$/GJ	5.5339	5.5314	0.0025	0.0%	5.3568	5.3538	0.0031	0.1%
6.11	T-SERVICE UNIT RATE	$/GJ	1.6704	1.6679	0.0025	0.2%	1.4933	1.4903	0.0031	0.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				Rate 170 - Average Ind. Interr. - 50% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,438.08	1,438.08	0.00	0.0%	3,490.32	3,490.32	0.00	0.0%
7.3	DISTRIBUTION CHG.	$	11,577.84	11,576.47	1.37	0.0%	87,398.40	87,312.59	85.81	0.1%
7.4	LOAD BALANCING	$	19,823.73	19,823.73	0.00	0.0%	317,821.47	317,821.47	0.00	0.0%
7.5	SALES COMMDTY	$	89,146.27	89,146.27	0.00	0.0%	1,485,044.44	1,485,044.44	0.00	0.0%
7.6	TOTAL SALES	$	121,985.93	121,984.55	1.37	0.0%	1,893,754.62	1,893,668.82	85.81	0.0%
7.7	TOTAL T-SERVICE	$	32,839.66	32,838.28	1.37	0.0%	408,710.19	408,624.38	85.81	0.0%
7.8	SALES UNIT RATE	$/m³	0.2038	0.2038	0.0000	0.0%	0.1898	0.1898	0.0000	0.0%
7.9	T-SERVICE UNIT RATE	$/m³	0.0549	0.0549	0.0000	0.0%	0.0410	0.0410	0.0000	0.0%
7.10	SALES UNIT RATE	$/GJ	5.2893	5.2892	0.0001	0.0%	4.9268	4.9266	0.0002	0.0%
7.11	T-SERVICE UNIT RATE	$/GJ	1.4239	1.4239	0.0001	0.0%	1.0633	1.0631	0.0002	0.0%

			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,490.32	3,490.32	0.00	0.0%	3,490.32	3,490.32	0.00	0.0%
8.3	DISTRIBUTION CHG.	$	79,837.90	79,779.90	58.00	0.1%	441,327.04	440,920.74	406.30	0.1%
8.4	LOAD BALANCING	$	317,821.44	317,821.44	0.00	0.0%	2,224,750.37	2,224,750.37	0.00	0.0%
8.5	SALES COMMDTY	$	1,485,044.29	1,485,044.29	0.00	0.0%	10,395,311.49	10,395,311.49	0.00	0.0%
8.6	TOTAL SALES	$	1,886,193.94	1,886,135.94	58.00	0.0%	13,064,879.22	13,064,472.92	406.30	0.0%
8.7	TOTAL T-SERVICE	$	401,149.65	401,091.65	58.00	0.0%	2,669,567.73	2,669,161.43	406.30	0.0%
8.8	SALES UNIT RATE	$/m³	0.1891	0.1891	0.0000	0.0%	0.1871	0.1871	0.0000	0.0%
8.9	T-SERVICE UNIT RATE	$/m³	0.0402	0.0402	0.0000	0.0%	0.0382	0.0382	0.0000	0.0%
8.10	SALES UNIT RATE	$/GJ	4.9071	4.9070	0.0002	0.0%	4.8556	4.8555	0.0002	0.0%
8.11	T-SERVICE UNIT RATE	$/GJ	1.0436	1.0435	0.0002	0.0%	0.9922	0.9920	0.0002	0.0%

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				**Heating, Water Htg. & Other Uses**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	268.93	267.51	1.42	0.5%	405.54	403.37	2.17	0.5%
1.4	LOAD BALANCING	§ $	165.65	165.65	0.00	0.0%	253.61	253.61	0.00	0.0%
1.5	SALES COMMDTY	$	457.22	457.22	0.00	0.0%	700.00	700.00	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	239.91	239.91	0.00	0.0%	367.31	367.31	0.00	0.0%
1.7	TOTAL SALES	$	1,393.66	1,392.25	1.42	0.1%	1,988.42	1,986.25	2.17	0.1%
1.8	TOTAL T-SERVICE	$	936.45	935.03	1.42	0.2%	1,288.41	1,286.25	2.17	0.2%
1.9	SALES UNIT RATE	$/m³	0.4549	0.4544	0.0005	0.1%	0.4239	0.4234	0.0005	0.1%
1.10	T-SERVICE UNIT RATE	$/m³	0.3056	0.3052	0.0005	0.2%	0.2747	0.2742	0.0005	0.2%
1.11	SALES UNIT RATE	$/GJ	11.8389	11.8269	0.0120	0.1%	11.0328	11.0207	0.0120	0.1%
1.12	T-SERVICE UNIT RATE	$/GJ	7.9549	7.9429	0.0120	0.2%	7.1488	7.1368	0.0120	0.2%

			Heating Only				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	172.47	171.57	0.90	0.5%	179.43	178.50	0.93	0.5%
2.4	LOAD BALANCING	§ $	105.69	105.69	0.00	0.0%	108.39	108.39	0.00	0.0%
2.5	SALES COMMDTY	$	291.73	291.73	0.00	0.0%	299.19	299.19	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	153.08	153.08	0.00	0.0%	156.99	156.99	0.00	0.0%
2.7	TOTAL SALES	$	984.93	984.02	0.90	0.1%	1,005.96	1,005.04	0.93	0.1%
2.8	TOTAL T-SERVICE	$	693.20	692.29	0.90	0.1%	706.77	705.85	0.93	0.1%
2.9	SALES UNIT RATE	$/m³	0.5038	0.5033	0.0005	0.1%	0.5017	0.5013	0.0005	0.1%
2.10	T-SERVICE UNIT RATE	$/m³	0.3546	0.3541	0.0005	0.1%	0.3525	0.3520	0.0005	0.1%
2.11	SALES UNIT RATE	$/GJ	13.1130	13.1009	0.0120	0.1%	13.0590	13.0470	0.0120	0.1%
2.12	T-SERVICE UNIT RATE	$/GJ	9.2290	9.2169	0.0120	0.1%	9.1751	9.1630	0.0120	0.1%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	436.14	433.81	2.33	0.5%	101.20	100.70	0.50	0.5%
3.4	LOAD BALANCING	§ $	272.91	272.91	0.00	0.0%	58.44	58.44	0.00	0.0%
3.5	SALES COMMDTY	$	753.27	753.27	0.00	0.0%	161.31	161.31	0.00	0.0%
	FEDERAL CARBON CHARGE	$	395.26	395.26	0.00	0.0%	84.64	84.64	0.00	0.0%
3.6	TOTAL SALES	$	2,119.54	2,117.21	2.33	0.1%	667.56	667.06	0.50	0.1%
3.7	TOTAL T-SERVICE	$	1,366.27	1,363.93	2.33	0.2%	506.25	505.75	0.50	0.1%
3.8	SALES UNIT RATE	$/m³	0.4199	0.4194	0.0005	0.1%	0.6175	0.6171	0.0005	0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.2707	0.2702	0.0005	0.2%	0.4683	0.4679	0.0005	0.1%
3.10	SALES UNIT RATE	$/GJ	10.9286	10.9166	0.0120	0.1%	16.0733	16.0613	0.0120	0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	7.0446	7.0326	0.0120	0.2%	12.1893	12.1773	0.0120	0.1%

			Heating & Water Htg.				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
4.1	VOLUME	m³	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
4.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	219.55	218.40	1.15	0.5%	212.52	211.41	1.11	0.5%
4.4	LOAD BALANCING	§ $	134.07	134.07	0.00	0.0%	129.75	129.75	0.00	0.0%
4.5	SALES COMMDTY	$	370.07	370.07	0.00	0.0%	358.13	358.13	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	194.18	194.18	0.00	0.0%	187.92	187.92	0.00	0.0%
4.7	TOTAL SALES	$	1,179.84	1,178.69	1.15	0.1%	1,150.28	1,149.17	1.11	0.1%
4.8	TOTAL T-SERVICE	$	809.77	808.62	1.15	0.1%	792.15	791.04	1.11	0.1%
4.9	SALES UNIT RATE	$/m³	0.4757	0.4753	0.0005	0.1%	0.4793	0.4788	0.0005	0.1%
4.10	T-SERVICE UNIT RATE	$/m³	0.3265	0.3261	0.0005	0.1%	0.3301	0.3296	0.0005	0.1%
4.11	SALES UNIT RATE	$/GJ	12.3827	12.3706	0.0120	0.1%	12.4749	12.4628	0.0120	0.1%
4.12	T-SERVICE UNIT RATE	$/GJ	8.4987	8.4866	0.0120	0.1%	8.5909	8.5789	0.0120	0.1%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,611.22	1,602.03	9.19	0.6%	2,067.49	2,055.58	11.91	0.6%
1.4	LOAD BALANCING	§ $	1,202.93	1,202.93	0.00	0.0%	1,557.96	1,557.96	0.00	0.0%
1.5	SALES COMMDTY	$	3,378.33	3,378.33	0.00	0.0%	4,375.42	4,375.42	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	1,770.05	1,770.05	0.00	0.0%	2,292.47	2,292.47	0.00	0.0%
1.7	TOTAL SALES	$	8,849.21	8,840.02	9.19	0.1%	11,180.02	11,168.12	11.91	0.1%
1.8	TOTAL T-SERVICE	$	5,470.88	5,461.68	9.19	0.2%	6,804.60	6,792.69	11.91	0.2%
1.9	SALES UNIT RATE	$/m³	0.3915	0.3910	0.0004	0.1%	0.3819	0.3815	0.0004	0.1%
1.10	T-SERVICE UNIT RATE	$/m³	0.2420	0.2416	0.0004	0.2%	0.2324	0.2320	0.0004	0.2%
1.11	SALES UNIT RATE	$/GJ	10.1888	10.1782	0.0106	0.1%	9.9390	9.9284	0.0106	0.1%
1.12	T-SERVICE UNIT RATE	$/GJ	6.2991	6.2885	0.0106	0.2%	6.0493	6.0387	0.0106	0.2%

			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	8,712.66	8,643.69	68.96	0.8%	15,973.76	15,835.83	137.93	0.9%
2.4	LOAD BALANCING	§ $	9,022.92	9,022.92	0.00	0.0%	18,045.78	18,045.78	0.00	0.0%
2.5	SALES COMMDTY	$	25,340.19	25,340.19	0.00	0.0%	50,680.23	50,680.23	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	13,276.78	13,276.78	0.00	0.0%	26,553.49	26,553.49	0.00	0.0%
2.7	TOTAL SALES	$	57,239.23	57,170.26	68.96	0.1%	112,139.93	112,002.01	137.93	0.1%
2.8	TOTAL T-SERVICE	$	31,899.04	31,830.07	68.96	0.2%	61,459.70	61,321.78	137.93	0.2%
2.9	SALES UNIT RATE	$/m³	0.3376	0.3372	0.0004	0.1%	0.3307	0.3303	0.0004	0.1%
2.10	T-SERVICE UNIT RATE	$/m³	0.1881	0.1877	0.0004	0.2%	0.1812	0.1808	0.0004	0.2%
2.11	SALES UNIT RATE	$/GJ	8.7863	8.7757	0.0106	0.1%	8.6068	8.5962	0.0106	0.1%
2.12	T-SERVICE UNIT RATE	$/GJ	4.8965	4.8860	0.0106	0.2%	4.7171	4.7065	0.0106	0.2%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,858.86	2,841.26	17.60	0.6%	3,838.69	3,812.70	25.99	0.7%
3.4	LOAD BALANCING	§ $	2,303.31	2,303.31	0.00	0.0%	3,400.46	3,400.46	0.00	0.0%
3.5	SALES COMMDTY	$	6,468.69	6,468.69	0.00	0.0%	9,549.93	9,549.93	0.00	0.0%
	FEDERAL CARBON CHARGE	$	3,389.22	3,389.22	0.00	0.0%	5,003.60	5,003.60	0.00	0.0%
3.6	TOTAL SALES	$	15,906.76	15,889.15	17.60	0.1%	22,679.36	22,653.37	25.99	0.1%
3.7	TOTAL T-SERVICE	$	9,438.07	9,420.47	17.60	0.2%	13,129.43	13,103.44	25.99	0.2%
3.8	SALES UNIT RATE	$/m³	0.3675	0.3671	0.0004	0.1%	0.3549	0.3545	0.0004	0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.2180	0.2176	0.0004	0.2%	0.2055	0.2051	0.0004	0.2%
3.10	SALES UNIT RATE	$/GJ	9.5650	9.5545	0.0106	0.1%	9.2375	9.2269	0.0106	0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	5.6753	5.6647	0.0106	0.2%	5.3477	5.3371	0.0106	0.2%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	8,919.13	8,850.17	68.96	0.8%	16,127.38	15,989.45	137.93	0.9%
4.4	LOAD BALANCING	§ $	9,022.92	9,022.92	0.00	0.0%	18,045.73	18,045.73	0.00	0.0%
4.5	SALES COMMDTY	$	25,340.19	25,340.19	0.00	0.0%	50,680.08	50,680.08	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	13,276.78	13,276.78	0.00	0.0%	26,553.41	26,553.41	0.00	0.0%
4.7	TOTAL SALES	$	57,445.70	57,376.73	68.96	0.1%	112,293.27	112,155.35	137.93	0.1%
4.8	TOTAL T-SERVICE	$	32,105.51	32,036.55	68.96	0.2%	61,613.20	61,475.27	137.93	0.2%
4.9	SALES UNIT RATE	$/m³	0.3388	0.3384	0.0004	0.1%	0.3311	0.3307	0.0004	0.1%
4.10	T-SERVICE UNIT RATE	$/m³	0.1893	0.1889	0.0004	0.2%	0.1817	0.1813	0.0004	0.2%
4.11	SALES UNIT RATE	$/GJ	8.8180	8.8074	0.0106	0.1%	8.6186	8.6080	0.0106	0.1%
4.12	T-SERVICE UNIT RATE	$/GJ	4.9282	4.9176	0.0106	0.2%	4.7289	4.7183	0.0106	0.2%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m^3	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,536.60	1,536.60	0.00	0.0%	1,536.60	1,536.60	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	14,194.71	14,143.08	51.64	0.4%	69,052.66	68,793.87	258.79	0.4%
1.4	LOAD BALANCING	$	18,049.13	18,049.13	0.00	0.0%	31,851.41	31,851.41	0.00	0.0%
1.5	SALES COMMDTY	$	50,689.64	50,689.64	0.00	0.0%	89,452.30	89,452.30	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	26,558.42	26,558.42	0.00	0.0%	46,867.80	46,867.80	0.00	0.0%
1.7	TOTAL SALES	$	111,028.51	110,976.87	51.64	0.0%	238,760.77	238,501.98	258.79	0.1%
1.8	TOTAL T-SERVICE	$	60,338.87	60,287.23	51.64	0.1%	149,308.47	149,049.68	258.79	0.2%
1.9	SALES UNIT RATE	$/m³	0.3273	0.3272	0.0002	0.0%	0.3989	0.3985	0.0004	0.1%
1.10	T-SERVICE UNIT RATE	$/m³	0.1779	0.1777	0.0002	0.1%	0.2494	0.2490	0.0004	0.2%
1.11	SALES UNIT RATE	$/GJ	8.5199	8.5160	0.0040	0.0%	10.3823	10.3710	0.0113	0.1%
1.12	T-SERVICE UNIT RATE	$/GJ	4.6302	4.6262	0.0040	0.1%	6.4925	6.4813	0.0113	0.2%

Rate 100 - Large Industrial Firm

			(A)	**(B)**	**CHANGE**	
					(A) - (B)	%
2.1	VOLUME	m^3	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,536.60	1,536.60	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	138,679.21	138,161.63	517.58	0.4%
2.4	LOAD BALANCING	$	79,819.16	79,819.16	0.00	0.0%
2.5	SALES COMMDTY	$	224,166.14	224,166.14	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	117,450.00	117,450.00	0.00	0.0%
2.7	TOTAL SALES	$	561,651.11	561,133.53	517.58	0.1%
2.8	TOTAL T-SERVICE	$	337,484.98	336,967.39	517.58	0.2%
2.9	SALES UNIT RATE	$/m³	0.3744	0.3741	0.0003	0.1%
2.10	T-SERVICE UNIT RATE	$/m³	0.2250	0.2246	0.0003	0.2%
2.11	SALES UNIT RATE	$/GJ	9.7458	9.7368	0.0090	0.1%
2.12	T-SERVICE UNIT RATE	$/GJ	5.8561	5.8471	0.0090	0.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				**Rate 145 - Average Commercial Interr.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,553.28	1,553.28	0.00	0.0%	1,553.28	1,553.28	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	18,828.74	18,820.00	8.74	0.0%	30,103.14	30,090.04	13.10	0.0%
3.4	LOAD BALANCING	$	14,082.04	14,082.04	0.00	0.0%	24,851.22	24,851.22	0.00	0.0%
3.5	SALES COMMDTY	$	50,504.21	50,504.21	0.00	0.0%	89,125.22	89,125.22	0.00	0.0%
	FEDERAL CARBON CHARGE	$	26,558.42	26,558.42	0.00	0.0%	46,867.87	46,867.87	0.00	0.0%
3.6	TOTAL SALES	$	111,526.69	111,517.96	8.74	0.0%	192,500.74	192,487.64	13.10	0.0%
3.7	TOTAL T-SERVICE	$	61,022.48	61,013.74	8.74	0.0%	103,375.52	103,362.42	13.10	0.0%
3.8	SALES UNIT RATE	$/m³	0.3288	0.3288	0.0000	0.0%	0.3216	0.3216	0.0000	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1799	0.1799	0.0000	0.0%	0.1727	0.1727	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	8.5582	8.5575	0.0007	0.0%	8.3707	8.3701	0.0006	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	4.6827	4.6820	0.0007	0.0%	4.4952	4.4946	0.0006	0.0%

			Rate 145 - Small Industrial Interr.				**Rate 145 - Average Industrial Interr.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,553.28	1,553.28	0.00	0.0%	1,553.28	1,553.28	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	19,104.62	19,095.88	8.74	0.0%	30,347.35	30,334.25	13.10	0.0%
4.4	LOAD BALANCING	$	14,082.04	14,082.04	0.00	0.0%	24,851.18	24,851.18	0.00	0.0%
4.5	SALES COMMDTY	$	50,504.21	50,504.21	0.00	0.0%	89,125.07	89,125.07	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	26,558.42	26,558.42	0.00	0.0%	46,867.80	46,867.80	0.00	0.0%
4.7	TOTAL SALES	$	111,802.57	111,793.84	8.74	0.0%	192,744.68	192,731.57	13.10	0.0%
4.8	TOTAL T-SERVICE	$	61,298.36	61,289.62	8.74	0.0%	103,619.60	103,606.50	13.10	0.0%
4.9	SALES UNIT RATE	$/m³	0.3296	0.3296	0.0000	0.0%	0.3220	0.3220	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.1807	0.1807	0.0000	0.0%	0.1731	0.1731	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	8.5793	8.5787	0.0007	0.0%	8.3813	8.3807	0.0006	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	4.7038	4.7032	0.0007	0.0%	4.5058	4.5052	0.0006	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,351.92	7,351.92	0.00	0.0%	7,351.92	7,351.92	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	15,021.88	14,933.99	87.88	0.6%	246,374.95	244,936.80	1,438.16	0.6%
5.4	LOAD BALANCING	$	26,317.98	26,317.98	0.00	0.0%	438,632.42	438,632.42	0.00	0.0%
5.5	SALES COMMDTY	$	89,102.78	89,102.78	0.00	0.0%	1,485,044.45	1,485,044.45	0.00	0.0%
5.6	FEDERAL CARBON CHARGE	$	46,867.87	46,867.87	0.00	0.0%	781,130.27	781,130.27	0.00	0.0%
5.7	TOTAL SALES	$	184,662.42	184,574.54	87.88	0.0%	2,958,534.01	2,957,095.85	1,438.16	0.0%
5.8	TOTAL T-SERVICE	$	95,559.65	95,471.76	87.88	0.1%	1,473,489.57	1,472,051.41	1,438.16	0.1%
5.9	SALES UNIT RATE	$/m³	0.3085	0.3084	0.0001	0.0%	0.2966	0.2964	0.0001	0.0%
5.10	T-SERVICE UNIT RATE	$/m³	0.1596	0.1595	0.0001	0.1%	0.1477	0.1476	0.0001	0.1%
5.11	SALES UNIT RATE	$/GJ	8.0299	8.0260	0.0038	0.0%	7.7189	7.7152	0.0038	0.0%
5.12	T-SERVICE UNIT RATE	$/GJ	4.1553	4.1515	0.0038	0.1%	3.8444	3.8406	0.0038	0.1%

			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,351.92	7,351.92	0.00	0.0%	7,792.32	7,792.32	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	196,755.02	195,782.92	972.09	0.5%	1,049,690.47	1,041,432.96	8,257.51	0.8%
6.4	LOAD BALANCING	$	438,632.37	438,632.37	0.00	0.0%	2,965,216.40	2,965,216.40	0.00	0.0%
6.5	SALES COMMDTY	$	1,485,044.30	1,485,044.30	0.00	0.0%	10,395,311.57	10,395,311.57	0.00	0.0%
6.6	FEDERAL CARBON CHARGE	$	781,130.20	781,130.20	0.00	0.0%	5,467,912.16	5,467,912.16	0.00	0.0%
6.7	TOTAL SALES	$	2,908,913.80	2,907,941.71	972.09	0.0%	19,885,922.92	19,877,665.40	8,257.51	0.0%
6.8	TOTAL T-SERVICE	$	1,423,869.50	1,422,897.41	972.09	0.1%	9,490,611.35	9,482,353.83	8,257.51	0.1%
6.9	SALES UNIT RATE	$/m³	0.2916	0.2915	0.0001	0.0%	0.2848	0.2846	0.0001	0.0%
6.10	T-SERVICE UNIT RATE	$/m³	0.1427	0.1426	0.0001	0.1%	0.1359	0.1358	0.0001	0.1%
6.11	SALES UNIT RATE	$/GJ	7.5895	7.5869	0.0025	0.0%	7.4119	7.4088	0.0031	0.0%
6.12	T-SERVICE UNIT RATE	$/GJ	3.7149	3.7124	0.0025	0.1%	3.5373	3.5343	0.0031	0.1%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR NON-OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				**Rate 170 - Average Ind. Interr. - 50% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,450.08	1,450.08	0.00	0.0%	3,502.32	3,502.32	0.00	0.0%
7.3	DISTRIBUTION CHG.	$	11,617.35	11,615.97	1.37	0.0%	88,056.82	87,971.02	85.81	0.1%
7.4	LOAD BALANCING	$	19,823.73	19,823.73	0.00	0.0%	317,821.47	317,821.47	0.00	0.0%
7.5	SALES COMMDTY	$	89,146.27	89,146.27	0.00	0.0%	1,485,044.44	1,485,044.44	0.00	0.0%
7.6	FEDERAL CARBON CHARGE	$	46,867.80	46,867.80	0.00	0.0%	781,130.27	781,130.27	0.00	0.0%
7.7	TOTAL SALES	$	168,905.23	168,903.85	1.37	0.0%	2,675,555.32	2,675,469.51	85.81	0.0%
7.8	TOTAL T-SERVICE	$	79,758.96	79,757.58	1.37	0.0%	1,190,510.88	1,190,425.08	85.81	0.0%
7.9	SALES UNIT RATE	$/m³	0.2822	0.2822	0.0000	0.0%	0.2682	0.2682	0.0000	0.0%
7.10	T-SERVICE UNIT RATE	$/m³	0.1332	0.1332	0.0000	0.0%	0.1193	0.1193	0.0000	0.0%
7.11	SALES UNIT RATE	$/GJ	7.3447	7.3446	0.0001	0.0%	6.9806	6.9804	0.0002	0.0%
7.12	T-SERVICE UNIT RATE	$/GJ	3.4682	3.4682	0.0001	0.0%	3.1061	3.1059	0.0002	0.0%

			Rate 170 - Average Ind. Interr. - 75% LF				**Rate 170 - Large Ind. Interr. - 75% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,502.32	3,502.32	0.00	0.0%	3,502.32	3,502.32	0.00	0.0%
8.3	DISTRIBUTION CHG.	$	80,496.32	80,438.32	58.00	0.1%	445,936.01	445,529.71	406.30	0.1%
8.4	LOAD BALANCING	$	317,821.44	317,821.44	0.00	0.0%	2,224,750.37	2,224,750.37	0.00	0.0%
8.5	SALES COMMDTY	$	1,485,044.29	1,485,044.29	0.00	0.0%	10,395,311.49	10,395,311.49	0.00	0.0%
8.6	FEDERAL CARBON CHARGE	$	781,130.20	781,130.20	0.00	0.0%	5,467,912.16	5,467,912.16	0.00	0.0%
8.7	TOTAL SALES	$	2,667,994.56	2,667,936.56	58.00	0.0%	18,537,412.35	18,537,006.04	406.30	0.0%
8.8	TOTAL T-SERVICE	$	1,182,950.27	1,182,892.27	58.00	0.0%	8,142,100.86	8,141,694.55	406.30	0.0%
8.9	SALES UNIT RATE	$/m³	0.2674	0.2674	0.0000	0.0%	0.2655	0.2654	0.0000	0.0%
8.1	T-SERVICE UNIT RATE	$/m³	0.1186	0.1186	0.0000	0.0%	0.1166	0.1166	0.0000	0.0%
8.11	SALES UNIT RATE	$/GJ	6.9609	6.9608	0.0002	0.0%	6.9093	6.9091	0.0002	0.0%
8.12	T-SERVICE UNIT RATE	$/GJ	3.0864	3.0862	0.0002	0.0%	3.0347	3.0346	0.0002	0.0%

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				**Heating, Water Htg. & Other Uses**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	268.93	267.51	1.42	0.5%	405.54	403.37	2.17	0.5%
1.4	LOAD BALANCING	§ $	165.65	165.65	0.00	0.0%	253.61	253.61	0.00	0.0%
1.5	SALES COMMDTY	$	457.22	457.22	0.00	0.0%	700.00	700.00	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
1.7	TOTAL SALES	$	1,153.75	1,152.33	1.42	0.1%	1,621.11	1,618.94	2.17	0.1%
1.8	TOTAL T-SERVICE	$	696.53	695.12	1.42	0.2%	921.11	918.94	2.17	0.2%
1.9	SALES UNIT RATE	$/m³	0.3766	0.3761	0.0005	0.1%	0.3456	0.3451	0.0005	0.1%
1.10	T-SERVICE UNIT RATE	$/m³	0.2273	0.2269	0.0005	0.2%	0.1964	0.1959	0.0005	0.2%
1.11	SALES UNIT RATE	$/GJ	9.8009	9.7889	0.0120	0.1%	8.9948	8.9827	0.0120	0.1%
1.12	T-SERVICE UNIT RATE	$/GJ	5.9169	5.9049	0.0120	0.2%	5.1108	5.0988	0.0120	0.2%

			Heating Only				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	172.47	171.57	0.90	0.5%	179.43	178.50	0.93	0.5%
2.4	LOAD BALANCING	§ $	105.69	105.69	0.00	0.0%	108.39	108.39	0.00	0.0%
2.5	SALES COMMDTY	$	291.73	291.73	0.00	0.0%	299.19	299.19	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
2.7	TOTAL SALES	$	831.85	830.95	0.90	0.1%	848.97	848.05	0.93	0.1%
2.8	TOTAL T-SERVICE	$	540.12	539.22	0.90	0.2%	549.78	548.86	0.93	0.2%
2.9	SALES UNIT RATE	$/m³	0.4255	0.4250	0.0005	0.1%	0.4234	0.4230	0.0005	0.1%
2.10	T-SERVICE UNIT RATE	$/m³	0.2763	0.2758	0.0005	0.2%	0.2742	0.2737	0.0005	0.2%
2.11	SALES UNIT RATE	$/GJ	11.0749	11.0629	0.0120	0.1%	11.0210	11.0090	0.0120	0.1%
2.12	T-SERVICE UNIT RATE	$/GJ	7.1910	7.1789	0.0120	0.2%	7.1371	7.1250	0.0120	0.2%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	436.14	433.81	2.33	0.5%	101.20	100.70	0.50	0.5%
3.4	LOAD BALANCING	§ $	272.91	272.91	0.00	0.0%	58.44	58.44	0.00	0.0%
3.5	SALES COMMDTY	$	753.27	753.27	0.00	0.0%	161.31	161.31	0.00	0.0%
	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
3.6	TOTAL SALES	$	1,724.28	1,721.95	2.33	0.1%	582.91	582.41	0.50	0.1%
3.7	TOTAL T-SERVICE	$	971.01	968.68	2.33	0.2%	421.61	421.11	0.50	0.1%
3.8	SALES UNIT RATE	$/m³	0.3416	0.3411	0.0005	0.1%	0.5392	0.5388	0.0005	0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1924	0.1919	0.0005	0.2%	0.3900	0.3896	0.0005	0.1%
3.10	SALES UNIT RATE	$/GJ	8.8906	8.8786	0.0120	0.1%	14.0353	14.0233	0.0120	0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	5.0066	4.9946	0.0120	0.2%	10.1513	10.1393	0.0120	0.1%

			Heating & Water Htg.				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
4.1	VOLUME	m³	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
4.2	CUSTOMER CHG.	$	261.96	261.96	0.00	0.0%	261.96	261.96	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	219.55	218.40	1.15	0.5%	212.52	211.41	1.11	0.5%
4.4	LOAD BALANCING	§ $	134.07	134.07	0.00	0.0%	129.75	129.75	0.00	0.0%
4.5	SALES COMMDTY	$	370.07	370.07	0.00	0.0%	358.13	358.13	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
4.7	TOTAL SALES	$	985.66	984.51	1.15	0.1%	962.36	961.25	1.11	0.1%
4.8	TOTAL T-SERVICE	$	615.58	614.44	1.15	0.2%	604.23	603.12	1.11	0.2%
4.9	SALES UNIT RATE	$/m³	0.3974	0.3970	0.0005	0.1%	0.4010	0.4005	0.0005	0.1%
4.10	T-SERVICE UNIT RATE	$/m³	0.2482	0.2478	0.0005	0.2%	0.2518	0.2513	0.0005	0.2%
4.11	SALES UNIT RATE	$/GJ	10.3447	10.3326	0.0120	0.1%	10.4369	10.4248	0.0120	0.1%
4.12	T-SERVICE UNIT RATE	$/GJ	6.4607	6.4486	0.0120	0.2%	6.5529	6.5409	0.0120	0.2%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,611.22	1,602.03	9.19	0.6%	2,067.49	2,055.58	11.91	0.6%
1.4	LOAD BALANCING	§ $	1,202.93	1,202.93	0.00	0.0%	1,557.96	1,557.96	0.00	0.0%
1.5	SALES COMMDTY	$	3,378.33	3,378.33	0.00	0.0%	4,375.42	4,375.42	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
1.7	TOTAL SALES	$	7,079.16	7,069.97	9.19	0.1%	8,887.56	8,875.65	11.91	0.1%
1.8	TOTAL T-SERVICE	$	3,700.83	3,691.63	9.19	0.2%	4,512.13	4,500.22	11.91	0.3%
1.9	SALES UNIT RATE	$/m³	0.3132	0.3127	0.0004	0.1%	0.3036	0.3032	0.0004	0.1%
1.10	T-SERVICE UNIT RATE	$/m³	0.1637	0.1633	0.0004	0.2%	0.1541	0.1537	0.0004	0.3%
1.11	SALES UNIT RATE	$/GJ	8.1508	8.1402	0.0106	0.1%	7.9010	7.8904	0.0106	0.1%
1.12	T-SERVICE UNIT RATE	$/GJ	4.2611	4.2505	0.0106	0.2%	4.0113	4.0007	0.0106	0.3%

			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	8,712.66	8,643.69	68.96	0.8%	15,973.76	15,835.83	137.93	0.9%
2.4	LOAD BALANCING	§ $	9,022.92	9,022.92	0.00	0.0%	18,045.78	18,045.78	0.00	0.0%
2.5	SALES COMMDTY	$	25,340.19	25,340.19	0.00	0.0%	50,680.23	50,680.23	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
2.7	TOTAL SALES	$	43,962.44	43,893.48	68.96	0.2%	85,586.44	85,448.52	137.93	0.2%
2.8	TOTAL T-SERVICE	$	18,622.25	18,553.29	68.96	0.4%	34,906.22	34,768.29	137.93	0.4%
2.9	SALES UNIT RATE	$/m³	0.2593	0.2589	0.0004	0.2%	0.2524	0.2520	0.0004	0.2%
2.10	T-SERVICE UNIT RATE	$/m³	0.1098	0.1094	0.0004	0.4%	0.1029	0.1025	0.0004	0.4%
2.11	SALES UNIT RATE	$/GJ	6.7483	6.7377	0.0106	0.2%	6.5688	6.5582	0.0106	0.2%
2.12	T-SERVICE UNIT RATE	$/GJ	2.8585	2.8480	0.0106	0.4%	2.6791	2.6685	0.0106	0.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,858.86	2,841.26	17.60	0.6%	3,838.69	3,812.70	25.99	0.7%
3.4	LOAD BALANCING	§ $	2,303.31	2,303.31	0.00	0.0%	3,400.46	3,400.46	0.00	0.0%
3.5	SALES COMMDTY	$	6,468.69	6,468.69	0.00	0.0%	9,549.93	9,549.93	0.00	0.0%
	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
3.6	TOTAL SALES	$	12,517.54	12,499.94	17.60	0.1%	17,675.75	17,649.76	25.99	0.1%
3.7	TOTAL T-SERVICE	$	6,048.86	6,031.25	17.60	0.3%	8,125.83	8,099.84	25.99	0.3%
3.8	SALES UNIT RATE	$/m³	0.2892	0.2888	0.0004	0.1%	0.2766	0.2762	0.0004	0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1397	0.1393	0.0004	0.3%	0.1272	0.1268	0.0004	0.3%
3.10	SALES UNIT RATE	$/GJ	7.5270	7.5165	0.0106	0.1%	7.1994	7.1889	0.0106	0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	3.6373	3.6267	0.0106	0.3%	3.3097	3.2991	0.0106	0.3%

			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	886.68	886.68	0.00	0.0%	886.68	886.68	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	8,919.13	8,850.17	68.96	0.8%	16,127.38	15,989.45	137.93	0.9%
4.4	LOAD BALANCING	§ $	9,022.92	9,022.92	0.00	0.0%	18,045.73	18,045.73	0.00	0.0%
4.5	SALES COMMDTY	$	25,340.19	25,340.19	0.00	0.0%	50,680.08	50,680.08	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
4.7	TOTAL SALES	$	44,168.92	44,099.95	68.96	0.2%	85,739.87	85,601.94	137.93	0.2%
4.8	TOTAL T-SERVICE	$	18,828.73	18,759.76	68.96	0.4%	35,059.79	34,921.86	137.93	0.4%
4.9	SALES UNIT RATE	$/m³	0.2605	0.2601	0.0004	0.2%	0.2528	0.2524	0.0004	0.2%
4.10	T-SERVICE UNIT RATE	$/m³	0.1110	0.1106	0.0004	0.4%	0.1034	0.1030	0.0004	0.4%
4.11	SALES UNIT RATE	$/GJ	6.7800	6.7694	0.0106	0.2%	6.5806	6.5700	0.0106	0.2%
4.12	T-SERVICE UNIT RATE	$/GJ	2.8902	2.8796	0.0106	0.4%	2.6909	2.6803	0.0106	0.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,536.60	1,536.60	0.00	0.0%	1,536.60	1,536.60	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	14,194.71	14,143.08	51.64	0.4%	69,052.66	68,793.87	258.79	0.4%
1.4	LOAD BALANCING	$	18,049.13	18,049.13	0.00	0.0%	31,851.41	31,851.41	0.00	0.0%
1.5	SALES COMMDTY	$	50,689.64	50,689.64	0.00	0.0%	89,452.30	89,452.30	0.00	0.0%
1.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
1.7	TOTAL SALES	$	84,470.09	84,418.45	51.64	0.1%	191,892.97	191,634.18	258.79	0.1%
1.8	TOTAL T-SERVICE	$	33,780.45	33,728.81	51.64	0.2%	102,440.67	102,181.88	258.79	0.3%
1.9	SALES UNIT RATE	$/m³	0.2490	0.2489	0.0002	0.1%	0.3206	0.3202	0.0004	0.1%
1.10	T-SERVICE UNIT RATE	$/m³	0.0996	0.0994	0.0002	0.2%	0.1711	0.1707	0.0004	0.3%
1.11	SALES UNIT RATE	$/GJ	6.4819	6.4780	0.0040	0.1%	8.3443	8.3330	0.0113	0.1%
1.12	T-SERVICE UNIT RATE	$/GJ	2.5922	2.5882	0.0040	0.2%	4.4545	4.4433	0.0113	0.3%

Rate 100 - Large Industrial Firm

			(A)	**(B)**	**CHANGE**	
					(A) - (B)	%
2.1	VOLUME	m³	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,536.60	1,536.60	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	138,679.21	138,161.63	517.58	0.4%
2.4	LOAD BALANCING	$	79,819.16	79,819.16	0.00	0.0%
2.5	SALES COMMDTY	$	224,166.14	224,166.14	0.00	0.0%
2.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%
2.7	TOTAL SALES	$	444,201.11	443,683.53	517.58	0.1%
2.8	TOTAL T-SERVICE	$	220,034.98	219,517.39	517.58	0.2%
2.9	SALES UNIT RATE	$/m³	0.2961	0.2958	0.0003	0.1%
2.10	T-SERVICE UNIT RATE	$/m³	0.1467	0.1463	0.0003	0.2%
2.11	SALES UNIT RATE	$/GJ	7.7078	7.6988	0.0090	0.1%
2.12	T-SERVICE UNIT RATE	$/GJ	3.8181	3.8091	0.0090	0.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				**Rate 145 - Average Commercial Interr.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,553.28	1,553.28	0.00	0.0%	1,553.28	1,553.28	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	18,828.74	18,820.00	8.74	0.0%	30,103.14	30,090.04	13.10	0.0%
3.4	LOAD BALANCING	$	14,082.04	14,082.04	0.00	0.0%	24,851.22	24,851.22	0.00	0.0%
3.5	SALES COMMDTY	$	50,504.21	50,504.21	0.00	0.0%	89,125.22	89,125.22	0.00	0.0%
3.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
3.7	TOTAL SALES	$	84,968.27	84,959.54	8.74	0.0%	145,632.87	145,619.77	13.10	0.0%
3.8	TOTAL T-SERVICE	$	34,464.06	34,455.32	8.74	0.0%	56,507.65	56,494.54	13.10	0.0%
3.9	SALES UNIT RATE	$/m³	0.2505	0.2505	0.0000	0.0%	0.2433	0.2433	0.0000	0.0%
4.0	T-SERVICE UNIT RATE	$/m³	0.1016	0.1016	0.0000	0.0%	0.0944	0.0944	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	6.5202	6.5195	0.0007	0.0%	6.3327	6.3321	0.0006	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	2.6447	2.6440	0.0007	0.0%	2.4572	2.4566	0.0006	0.0%

			Rate 145 - Small Industrial Interr.				**Rate 145 - Average Industrial Interr.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,553.28	1,553.28	0.00	0.0%	1,553.28	1,553.28	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	19,104.62	19,095.88	8.74	0.0%	30,347.35	30,334.25	13.10	0.0%
4.4	LOAD BALANCING	$	14,082.04	14,082.04	0.00	0.0%	24,851.18	24,851.18	0.00	0.0%
4.5	SALES COMMDTY	$	50,504.21	50,504.21	0.00	0.0%	89,125.07	89,125.07	0.00	0.0%
4.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
4.7	TOTAL SALES	$	85,244.15	85,235.42	8.74	0.0%	145,876.88	145,863.78	13.10	0.0%
4.8	TOTAL T-SERVICE	$	34,739.94	34,731.20	8.74	0.0%	56,751.81	56,738.70	13.10	0.0%
4.9	SALES UNIT RATE	$/m³	0.2513	0.2513	0.0000	0.0%	0.2437	0.2437	0.0000	0.0%
4.10	T-SERVICE UNIT RATE	$/m³	0.1024	0.1024	0.0000	0.0%	0.0948	0.0948	0.0000	0.0%
4.11	SALES UNIT RATE	$/GJ	6.5413	6.5407	0.0007	0.0%	6.3433	6.3427	0.0006	0.0%
4.12	T-SERVICE UNIT RATE	$/GJ	2.6658	2.6652	0.0007	0.0%	2.4678	2.4672	0.0006	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,351.92	7,351.92	0.00	0.0%	7,351.92	7,351.92	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	15,021.88	14,933.99	87.88	0.6%	246,374.95	244,936.80	1,438.16	0.6%
5.4	LOAD BALANCING	$	26,317.98	26,317.98	0.00	0.0%	438,632.42	438,632.42	0.00	0.0%
5.5	SALES COMMDTY	$	89,102.78	89,102.78	0.00	0.0%	1,485,044.45	1,485,044.45	0.00	0.0%
5.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
5.7	TOTAL SALES	$	137,794.55	137,706.67	87.88	0.1%	2,177,403.74	2,175,965.58	1,438.16	0.1%
5.8	TOTAL T-SERVICE	$	48,691.77	48,603.89	87.88	0.2%	692,359.29	690,921.13	1,438.16	0.2%
5.9	SALES UNIT RATE	$/m³	0.2302	0.2301	0.0001	0.1%	0.2183	0.2181	0.0001	0.1%
5.10	T-SERVICE UNIT RATE	$/m³	0.0813	0.0812	0.0001	0.2%	0.0694	0.0693	0.0001	0.2%
5.11	SALES UNIT RATE	$/GJ	5.9919	5.9880	0.0038	0.1%	5.6809	5.6772	0.0038	0.1%
5.12	T-SERVICE UNIT RATE	$/GJ	2.1173	2.1135	0.0038	0.2%	1.8064	1.8026	0.0038	0.2%

			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,351.92	7,351.92	0.00	0.0%	7,792.32	7,792.32	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	196,755.02	195,782.92	972.09	0.5%	1,049,690.47	1,041,432.96	8,257.51	0.8%
6.4	LOAD BALANCING	$	438,632.37	438,632.37	0.00	0.0%	2,965,216.40	2,965,216.40	0.00	0.0%
6.5	SALES COMMDTY	$	1,485,044.30	1,485,044.30	0.00	0.0%	10,395,311.57	10,395,311.57	0.00	0.0%
6.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
6.7	TOTAL SALES	$	2,127,783.61	2,126,811.51	972.09	0.0%	14,418,010.76	14,409,753.25	8,257.51	0.1%
6.8	TOTAL T-SERVICE	$	642,739.31	641,767.22	972.09	0.2%	4,022,699.19	4,014,441.68	8,257.51	0.2%
6.9	SALES UNIT RATE	$/m³	0.2133	0.2132	0.0001	0.0%	0.2065	0.2063	0.0001	0.1%
6.10	T-SERVICE UNIT RATE	$/m³	0.0644	0.0643	0.0001	0.2%	0.0576	0.0575	0.0001	0.2%
6.11	SALES UNIT RATE	$/GJ	5.5515	5.5489	0.0025	0.0%	5.3739	5.3708	0.0031	0.1%
6.12	T-SERVICE UNIT RATE	$/GJ	1.6769	1.6744	0.0025	0.2%	1.4993	1.4963	0.0031	0.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS
INCLUDING FEDERAL CARBON PRICING IMPACTS FOR OBPS PARTICIPANTS AND RIDER K BILL 32

(A) EB-2021-0219 + 2022 ICM vs (B) EB-2021-0219

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				**Rate 170 - Average Ind. Interr. - 50% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,450.08	1,450.08	0.00	0.0%	3,502.32	3,502.32	0.00	0.0%
7.3	DISTRIBUTION CHG.	$	11,617.35	11,615.97	1.37	0.0%	88,056.82	87,971.02	85.81	0.1%
7.4	LOAD BALANCING	$	19,823.73	19,823.73	0.00	0.0%	317,821.47	317,821.47	0.00	0.0%
7.5	SALES COMMDTY	$	89,146.27	89,146.27	0.00	0.0%	1,485,044.44	1,485,044.44	0.00	0.0%
7.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
7.7	TOTAL SALES	$	122,037.43	122,036.06	1.37	0.0%	1,894,425.05	1,894,339.24	85.81	0.0%
7.8	TOTAL T-SERVICE	$	32,891.16	32,889.79	1.37	0.0%	409,380.61	409,294.81	85.81	0.0%
7.9	SALES UNIT RATE	$/m³	0.2039	0.2039	0.0000	0.0%	0.1899	0.1899	0.0000	0.0%
7.10	T-SERVICE UNIT RATE	$/m³	0.0549	0.0549	0.0000	0.0%	0.0410	0.0410	0.0000	0.0%
7.11	SALES UNIT RATE	$/GJ	5.3067	5.3066	0.0001	0.0%	4.9426	4.9424	0.0002	0.0%
7.12	T-SERVICE UNIT RATE	$/GJ	1.4302	1.4302	0.0001	0.0%	1.0681	1.0679	0.0002	0.0%

			Rate 170 - Average Ind. Interr. - 75% LF				**Rate 170 - Large Ind. Interr. - 75% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,502.32	3,502.32	0.00	0.0%	3,502.32	3,502.32	0.00	0.0%
8.3	DISTRIBUTION CHG.	$	80,496.32	80,438.32	58.00	0.1%	445,936.01	445,529.71	406.30	0.1%
8.4	LOAD BALANCING	$	317,821.44	317,821.44	0.00	0.0%	2,224,750.37	2,224,750.37	0.00	0.0%
8.5	SALES COMMDTY	$	1,485,044.29	1,485,044.29	0.00	0.0%	10,395,311.49	10,395,311.49	0.00	0.0%
8.6	FEDERAL CARBON CHARGE	$	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
8.7	TOTAL SALES	$	1,886,864.36	1,886,806.36	58.00	0.0%	13,069,500.19	13,069,093.89	406.30	0.0%
8.8	TOTAL T-SERVICE	$	401,820.08	401,762.08	58.00	0.0%	2,674,188.70	2,673,782.40	406.30	0.0%
8.9	SALES UNIT RATE	$/m³	0.1891	0.1891	0.0000	0.0%	0.1872	0.1871	0.0000	0.0%
8.1	T-SERVICE UNIT RATE	$/m³	0.0403	0.0403	0.0000	0.0%	0.0383	0.0383	0.0000	0.0%
8.11	SALES UNIT RATE	$/GJ	4.9229	4.9228	0.0002	0.0%	4.8713	4.8711	0.0002	0.0%
8.12	T-SERVICE UNIT RATE	$/GJ	1.0484	1.0482	0.0002	0.0%	0.9967	0.9966	0.0002	0.0%

UNION RATE ZONES
Calculation of 2022 ICM Bill Impacts
Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

		Approved - EB-2021-0219 (1)		Proposed - EB-2021-0148			Bill Impact	
Line No.	Particulars	Total Bill ($)	Unit Rate (cents/m³)	Total Bill ($)	Unit Rate (cents/m³)	Total Bill Change ($)	Including Federal Carbon Charge (%)	Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate 01							
1	Delivery Charges	489	22.2200	489	22.2450	0.55	0.1%	0.1%
2	Federal Carbon Charge	172	7.8300	172	7.8300	-	0.0%	0.0%
3	Gas Supply Charges (2)	556	25.2514	556	25.2514	-	0.0%	0.0%
4	Total Bill	1,217	55.3018	1,217	55.3268	0.55	0.0%	0.1%
5	Sales Service Impact					0.55	0.0%	0.1%
6	Bundled-T (Direct Purchase) Impact					0.55	0.1%	0.1%
	Small Rate 10							
7	Delivery Charges	5,240	8.7326	5,253	8.7555	14	0.3%	0.3%
8	Federal Carbon Charge	4,698	7.8300	4,698	7.8300	-	0.0%	0.0%
9	Gas Supply Charges (2)	13,950	23.2500	13,950	23.2500	-	0.0%	0.0%
10	Total Bill	23,888	39.8126	23,901	39.8355	14	0.1%	0.1%
11	Sales Service Impact					14	0.1%	0.1%
12	Bundled-T (Direct Purchase) Impact					14	0.1%	0.2%
	Large Rate 10							
13	Delivery Charges	17,128	6.8514	17,186	6.8743	57	0.3%	0.3%
14	Federal Carbon Charge	19,575	7.8300	19,575	7.8300	-	0.0%	0.0%
15	Gas Supply Charges (2)	58,125	23.2500	58,125	23.2500	-	0.0%	0.0%
16	Total Bill	94,828	37.9314	94,886	37.9543	57	0.1%	0.1%
17	Sales Service Impact					57	0.1%	0.1%
18	Bundled-T (Direct Purchase) Impact					57	0.1%	0.2%
	Small Rate 20							
19	Delivery Charges	90,953	3.0318	91,295	3.0432	342	0.4%	0.4%
20	Federal Carbon Charge	234,900	7.8300	234,900	7.8300	-	0.0%	0.0%
21	Gas Supply Charges (2)	570,456	19.0152	570,456	19.0152	-	0.0%	0.0%
22	Total Bill	896,309	29.8770	896,651	29.8884	342	0.0%	0.1%
23	Sales Service Impact					342	0.0%	0.1%
24	Bundled-T (Direct Purchase) Impact					342	0.1%	0.2%
	Large Rate 20							
25	Delivery Charges	355,876	2.3725	357,340	2.3823	1,464	0.4%	0.4%
26	Federal Carbon Charge	1,174,500	7.8300	1,174,500	7.8300	-	0.0%	0.0%
27	Gas Supply Charges (2)	2,798,517	18.6568	2,798,517	18.6568	-	0.0%	0.0%
28	Total Bill	4,328,893	28.8593	4,330,356	28.8690	1,464	0.0%	0.0%
29	Sales Service Impact					1,464	0.0%	0.0%
30	Bundled-T (Direct Purchase) Impact					1,464	0.1%	0.2%
	Average Rate 25							
31	Delivery Charges	74,481	3.2739	74,950	3.2945	469	0.6%	0.6%
32	Federal Carbon Charge	178,133	7.8300	178,133	7.8300	-	0.0%	0.0%
33	Gas Supply Charges (2)	401,490	17.6479	401,490	17.6479	-	0.0%	0.0%
34	Total Bill	654,103	28.7518	654,572	28.7724	469	0.1%	0.1%
35	Sales Service Impact					469	0.1%	0.1%
36	T-Service (Direct Purchase) Impact					469	0.2%	0.6%
	Small Rate 100							
37	Delivery Charges	323,228	1.1971	326,790	1.2103	3,562	1.1%	1.1%
38	Federal Carbon Charge	2,114,100	7.8300	2,114,100	7.8300	-	0.0%	0.0%
39	Gas Supply Charges (2)	5,938,923	21.9960	5,938,923	21.9960	-	0.0%	0.0%
40	Total Bill	8,376,251	31.0232	8,379,812	31.0363	3,562	0.0%	0.1%
41	Sales Service Impact					3,562	0.0%	0.1%
42	T-Service (Direct Purchase) Impact					3,562	0.1%	1.1%
	Large Rate 100							
43	Delivery Charges	2,640,428	1.1002	2,670,702	1.1128	30,274	1.1%	1.1%
44	Federal Carbon Charge	18,792,000	7.8300	18,792,000	7.8300	-	0.0%	0.0%
45	Gas Supply Charges (2)	52,213,993	21.7558	52,213,993	21.7558	-	0.0%	0.0%
46	Total Bill	73,646,421	30.6860	73,676,695	30.6986	30,274	0.0%	0.1%
47	Sales Service Impact					30,274	0.0%	0.1%
48	T-Service (Direct Purchase) Impact					30,274	0.1%	1.1%

Notes:
(1) EB-2021-0219 Decision and Order, September 23, 2021.
(2) Gas Supply charges based on Union North East Zone.

UNION RATE ZONES
Calculation of 2022 ICM Bill Impacts
Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Approved - EB-2021-0219 (1) Total Bill ($)	Approved - EB-2021-0219 (1) Unit Rate (cents/m^3)	Proposed - EB-2021-0148 Total Bill ($)	Proposed - EB-2021-0148 Unit Rate (cents/m^3)	Proposed - EB-2021-0148 Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Bill Impact Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M1							
1	Delivery Charges	415	18.8427	414	18.8400	(0.06)	0.0%	0.0%
2	Federal Carbon Charge	172	7.8300	172	7.8300	-	0.0%	0.0%
3	Gas Supply Charges	370	16.8387	370	16.8387	-	0.0%	0.0%
4	Total Bill	957	43.5114	957	43.5086	(0.06)	0.0%	0.0%
5	Sales Service Impact					(0.06)	0.0%	0.0%
6	Direct Purchase Impact					(0.06)	0.0%	0.0%
	Small Rate M2							
7	Delivery Charges	4,393	7.3216	4,392	7.3205	(1)	0.0%	0.0%
8	Federal Carbon Charge	4,698	7.8300	4,698	7.8300	-	0.0%	0.0%
9	Gas Supply Charges	10,104	16.8392	10,104	16.8392	-	0.0%	0.0%
10	Total Bill	19,194	31.9908	19,194	31.9897	(1)	0.0%	0.0%
11	Sales Service Impact					(1)	0.0%	0.0%
12	Direct Purchase Impact					(1)	0.0%	0.0%
	Large Rate M2							
13	Delivery Charges	14,809	5.9235	14,806	5.9224	(3)	0.0%	0.0%
14	Federal Carbon Charge	19,575	7.8300	19,575	7.8300	-	0.0%	0.0%
15	Gas Supply Charges	42,098	16.8392	42,098	16.8392	-	0.0%	0.0%
16	Total Bill	76,482	30.5927	76,479	30.5916	(3)	0.0%	0.0%
17	Sales Service Impact					(3)	0.0%	0.0%
18	Direct Purchase Impact					(3)	0.0%	0.0%
	Small Rate M4							
19	Delivery Charges	52,841	6.0389	52,832	6.0379	(9)	0.0%	0.0%
20	Federal Carbon Charge	68,513	7.8300	68,513	7.8300	-	0.0%	0.0%
21	Gas Supply Charges	147,343	16.8392	147,343	16.8392	-	0.0%	0.0%
22	Total Bill	268,696	30.7081	268,687	30.7071	(9)	0.0%	0.0%
23	Sales Service Impact					(9)	0.0%	0.0%
24	Direct Purchase Impact					(9)	0.0%	0.0%
	Large Rate M4							
25	Delivery Charges	417,481	3.4790	417,388	3.4782	(93)	0.0%	0.0%
26	Federal Carbon Charge	939,600	7.8300	939,600	7.8300	-	0.0%	0.0%
27	Gas Supply Charges	2,020,704	16.8392	2,020,704	16.8392	-	0.0%	0.0%
28	Total Bill	3,377,785	28.1482	3,377,692	28.1474	(93)	0.0%	0.0%
29	Sales Service Impact					(93)	0.0%	0.0%
30	Direct Purchase Impact					(93)	0.0%	0.0%
	Small Rate M5							
31	Delivery Charges	35,419	4.2932	35,419	4.2932	-	0.0%	0.0%
32	Federal Carbon Charge	64,598	7.8300	64,598	7.8300	-	0.0%	0.0%
33	Gas Supply Charges	138,923	16.8392	138,923	16.8392	-	0.0%	0.0%
34	Total Bill	238,940	28.9624	238,940	28.9624	-	0.0%	0.0%
35	Sales Service Impact					-	0.0%	0.0%
36	Direct Purchase Impact					-	0.0%	0.0%
	Large Rate M5							
37	Delivery Charges	204,257	3.1424	204,257	3.1424	-	0.0%	0.0%
38	Federal Carbon Charge	508,950	7.8300	508,950	7.8300	-	0.0%	0.0%
39	Gas Supply Charges	1,094,548	16.8392	1,094,548	16.8392	-	0.0%	0.0%
40	Total Bill	1,807,755	27.8116	1,807,755	27.8116	-	0.0%	0.0%
41	Sales Service Impact					-	0.0%	0.0%
42	Direct Purchase Impact					-	0.0%	0.0%
	Small Rate M7							
43	Delivery Charges	811,015	2.2528	810,664	2.2518	(350)	0.0%	0.0%
44	Federal Carbon Charge	2,818,800	7.8300	2,818,800	7.8300	-	0.0%	0.0%
45	Gas Supply Charges	6,062,112	16.8392	6,062,112	16.8392	-	0.0%	0.0%
46	Total Bill	9,691,927	26.9220	9,691,576	26.9210	(350)	0.0%	0.0%
47	Sales Service Impact					(350)	0.0%	0.0%
48	Direct Purchase Impact					(350)	0.0%	0.0%
	Large Rate M7							
49	Delivery Charges	3,182,715	6.1206	3,181,186	6.1177	(1,529)	0.0%	0.0%
50	Federal Carbon Charge	4,071,600	7.8300	4,071,600	7.8300	-	0.0%	0.0%
51	Gas Supply Charges	8,756,384	16.8392	8,756,384	16.8392	-	0.0%	0.0%
52	Total Bill	16,010,699	30.7898	16,009,170	30.7869	(1,529)	0.0%	0.0%
53	Sales Service Impact					(1,529)	0.0%	0.0%
54	Direct Purchase Impact					(1,529)	0.0%	0.0%

Notes:
(1) EB-2021-0219 Decision and Order, September 23, 2021.

UNION RATE ZONES
Calculation of 2022 ICM Bill Impacts
Sales Service and Direct Purchase Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Approved - EB-2021-0219 (1) Total Bill ($)	Approved Unit Rate (cents/m^3)	Proposed - EB-2021-0148 Total Bill ($)	Proposed Unit Rate (cents/m^3)	Total Bill Change ($)	Bill Impact Including Federal Carbon Charge (%)	Bill Impact Excluding Federal Carbon Charge (%)
		(a)	(b)	(c)	(d)	(e) = (c - a)	(f) = (e / a)	(g)
	Small Rate M9							
1	Delivery Charges	192,354	2.7677	192,308	2.7670	(46)		0.0%
2	Gas Supply Charges	1,170,324	16.8392	1,170,324	16.8392	-		0.0%
3	Total Bill	1,362,678	19.6069	1,362,632	19.6062	(46)		0.0%
4	Sales Service Impact					(46)		0.0%
5	Direct Purchase Impact					(46)		0.0%
	Large Rate M9							
6	Delivery Charges	571,772	2.8336	571,635	2.8330	(137)		0.0%
7	Gas Supply Charges	3,397,814	16.8392	3,397,814	16.8392	-		0.0%
8	Total Bill	3,969,586	19.6728	3,969,449	19.6722	(137)		0.0%
9	Sales Service Impact					(137)		0.0%
10	Direct Purchase Impact					(137)		0.0%
	Average Rate M10							
11	Delivery Charges	7,536	7.9747	7,535	7.9736	(1)		0.0%
12	Gas Supply Charges	15,913	16.8392	15,913	16.8392	-		0.0%
13	Total Bill	23,449	24.8139	23,448	24.8128	(1)		0.0%
14	Sales Service Impact					(1)		0.0%
15	Direct Purchase Impact					(1)		0.0%
	Small Rate T1							
16	Delivery Charges	167,946	2.2283	167,914	2.2279	(32)	0.0%	0.0%
17	Federal Carbon Charge	590,147	7.8300	590,147	7.8300	-	0.0%	0.0%
18	Gas Supply Charges	1,269,171	16.8392	1,269,171	16.8392	-	0.0%	0.0%
19	Total Bill	2,027,264	26.8975	2,027,232	26.8971	(32)	0.0%	0.0%
20	Sales Service Impact					(32)	0.0%	0.0%
21	Direct Purchase Impact					(32)	0.0%	0.0%
	Average Rate T1							
22	Delivery Charges	261,709	2.2628	261,648	2.2622	(61)	0.0%	0.0%
23	Federal Carbon Charge	905,613	7.8300	905,613	7.8300	-	0.0%	0.0%
24	Gas Supply Charges	1,947,611	16.8392	1,947,611	16.8392	-	0.0%	0.0%
25	Total Bill	3,114,933	26.9320	3,114,872	26.9314	(61)	0.0%	0.0%
26	Sales Service Impact					(61)	0.0%	0.0%
27	Direct Purchase Impact					(61)	0.0%	0.0%
	Large Rate T1							
28	Delivery Charges	591,056	2.3066	590,890	2.3060	(166)	0.0%	0.0%
29	Federal Carbon Charge	2,006,365	7.8300	2,006,365	7.8300	-	0.0%	0.0%
30	Gas Supply Charges	4,314,890	16.8392	4,314,890	16.8392	-	0.0%	0.0%
31	Total Bill	6,912,312	26.9758	6,912,146	26.9752	(166)	0.0%	0.0%
32	Sales Service Impact					(166)	0.0%	0.0%
33	Direct Purchase Impact					(166)	0.0%	0.0%
	Small Rate T2							
34	Delivery Charges	759,220	1.2813	758,814	1.2806	(406)	-0.1%	-0.1%
35	Federal Carbon Charge	4,639,745	7.8300	4,639,745	7.8300	-	0.0%	0.0%
36	Gas Supply Charges	9,978,236	16.8392	9,978,236	16.8392	-	0.0%	0.0%
37	Total Bill	15,377,201	25.9505	15,376,795	25.9498	(406)	0.0%	0.0%
38	Sales Service Impact					(406)	0.0%	0.0%
39	Direct Purchase Impact					(406)	0.0%	-0.1%
	Average Rate T2							
40	Delivery Charges	1,858,591	0.9397	1,857,162	0.9390	(1,429)	-0.1%	-0.1%
41	Federal Carbon Charge	15,486,945	7.8300	15,486,945	7.8300	-	0.0%	0.0%
42	Gas Supply Charges	33,306,228	16.8392	33,306,228	16.8392	-	0.0%	0.0%
43	Total Bill	50,651,765	25.6089	50,650,336	25.6082	(1,429)	0.0%	0.0%
44	Sales Service Impact					(1,429)	0.0%	0.0%
45	Direct Purchase Impact					(1,429)	0.0%	-0.1%
	Large Rate T2							
46	Delivery Charges	3,083,695	0.8332	3,081,132	0.8325	(2,563)	-0.1%	-0.1%
47	Federal Carbon Charge	28,977,969	7.8300	28,977,969	7.8300	-	0.0%	0.0%
48	Gas Supply Charges	62,320,027	16.8392	62,320,027	16.8392	-	0.0%	0.0%
49	Total Bill	94,381,691	25.5024	94,379,127	25.5017	(2,563)	0.0%	0.0%
50	Sales Service Impact					(2,563)	0.0%	0.0%
51	Direct Purchase Impact					(2,563)	0.0%	-0.1%
	Large Rate T3							
52	Delivery Charges	5,948,814	2.1814	5,946,784	2.1806	(2,030)		0.0%
53	Gas Supply Charges	45,922,519	16.8392	45,922,519	16.8392	-		0.0%
54	Total Bill	51,871,333	19.0206	51,869,303	19.0198	(2,030)		0.0%
55	Sales Service Impact					(2,030)		0.0%
56	Direct Purchase Impact					(2,030)		0.0%

Notes:
(1) EB-2021-0219 Decision and Order, September 23, 2021.

BUSINESS CASES OF ICM PROJECTS

1. This section provides the business cases for the proposed ICM projects as follows:

   EGD Rate Zone

   - St. Laurent Ottawa North Replacement (Phase 3)
   - NPS 20 Replacement Cherry to Bathurst

   Union Rate Zones

   - Dawn to Cuthbert Replacement and Retrofits
   - Byron Transmission Station
   - Kirkland Lake Lateral Replacement

2. The business case summaries provide a description of each of the projects' need, prudence, costs and expected in-service date, with an overview of options considered.

3. The St. Laurent Ottawa North Replacement (Phase 3)[1] and the NPS 20 Replacement Cherry to Bathurst[2] projects in the EGD rate zone are subject to a Leave to Construct ("LTC") application where the need for the projects has been or will be addressed. The St Laurent Ottawa North Replacement (Phase 3) project LTC Application is currently being reviewed by the OEB. The NPS 20 Replacement Cherry to Bathurst LTC Application was approved by the OEB on December 17, 2020.

4. The Dawn to Cuthbert Replacement and Retrofits, the Byron Transmission Station and the Kirkland Lake Lateral Replacement projects in the Union Rate Zones do not require a LTC approval. To explain the need for these projects, Enbridge Gas is

1 EB-2020-0293.
2 EB-2020-0136.

providing the business case for each of the projects. Additionally, for each of these projects Enbridge Gas has prepared evidence similar to what would be filed in an LTC application in relation to the items relevant to an ICM determination (purpose, need and timing, alternatives and project costs). This evidence is filed as Appendices A to C to this Exhibit.

Business Case Summaries for ICM Projects by Rate Zone

EGD Rate Zone

St. Laurent Ottawa North Replacement (Phase 3)	
Budget: $88.5 million Projected In-Service Date: December, 2022 In-Service Capital Spend: $86.0 million 2022 in-service $2.5 million 2023 in-service	Category of Investment: System Renewal Project Description and Drivers: • The St. Laurent Ottawa North Replacement project comprises of replacement of approximately 16 km of steel gas distribution main of NPS 12 extra high pressure (XHP) steel (ST) pipeline and approximately 400 m of NPS 16 XHP ST pipeline in the city of Ottawa, Ontario. The existing pipeline serves over 165,000 customers in Ottawa, Ontario and Gatineau Quebec. The project is required due to integrity issues with the pipeline and will be completed in multiple phases over multiple years. Phase 1 and Phase 2 were discussed in the EB-2019-0006 proceeding. Enbridge Gas has filed a Leave to Construct application for Phase 3 and Phase 4 of the Project in EB-2020-0293, where the Company is proposing to replace the existing St. Laurent pipeline with approximately 9 km of NPS 12 XHP ST and approximately 2.4 km of NPS 16 XHP ST

	natural gas pipeline. The project phases, facilities and timing is provided in the St. Laurent Leave to Construct application[3]. • In this application, Enbridge Gas is seeking ICM funding approval of Phase 3 of the project. • Analysis conducted by Enbridge Gas as part of the Distribution Integrity Management Program (DIMP) and Asset Management Plan asset health review identified the St. Laurent Pipeline as requiring replacement due to its condition and subsequent risk. • The budget covers all costs related to material, construction and labour, environmental projection measures, land acquisitions, contingencies, overheads and interest during construction. <u>Other Options Considered:</u> • Enbridge Gas considered two options for the project. The first option was to reactively repair leaks as they occur. The second option was to replace the St. Laurent Pipeline. In order to determine which option to proceed with, Enbridge Gas also considered retrofitting the St. Laurent Pipeline to allow for in-line inspections. • Retrofitting the St. Laurent Pipeline would allow in-line inspections to be completed. This would provide a full understanding of the condition of the pipeline and potentially allow for a more proactive repair program or provide information that would indicate replacement is required. However, Enbridge Gas decided to forego the retrofits as even with the ability to in-line inspect the St. Laurent Pipeline, there was still a high

3 EB-2020-0293, updated: 2021-03-04, Exhibit B, Tab 1, Schedule 1, Table 14, page 47 of 48.

	probability that the Company would need to spend additional capital to address defects identified on the line. • The option to repair has the advantage of spreading capital and O&M expenditures over multiple years. However, disadvantages include the number of integrity digs required over the next 40 years, disruptions to traffic, local businesses and residents as a result of the digs, existing depth of cover issues will remain, increased O&M costs as leaks become more common, continued degradation of the vintage steel pipe, increased security of supply risk and public safety and environmental concerns. • The option to replace the segment is the preferred option as it addresses and improves the entire segment of the pipeline, reduces O&M costs, reduces the probability of pipeline failure and the new asset will be constructed using modern standards and materials allowing for additional protection against and mitigation of third party damages. These outweigh the disadvantages of a large upfront capital investment and public inconvenience during the construction of the project. Enbridge Gas applied the Binary Screening Criteria outlined in the approved Integrated Resource Planning Framework (EB-2020-0091) and has determined that the project does not warrant further IRPA assessment as the need/constraint occurs within the 3-year time horizon. Enbridge Gas filed a Leave to Construct application with the OEB for the St. Laurent Ottawa North Replacement Project on March 2nd, 2021 under docket number EB-2020-0293. An updated application was filed

	on September 10th, 2021 including refinements and adjustments to the original project construction schedule and costs. The segments of pipeline have been reclassified between Phases 3 and 4, however no pipeline segments have been added or removed. The budget of $88.5 million covers all costs related to material, construction and labour, land costs, contingencies, overheads, and interest during construction. The Phase 4 budget is $35.2M, for a total projet cost of $123.7M.

NPS 20 Replacement Cherry to Bathurst	
Budget: $129.9 million Projected In-Service Date: October, 2022 In-Service Capital Spend: $126.7 million 2022 in-service $3.2 million 2023 in-service	Category of Investment: System Renewal Project Description and Drivers: • Replacement of approximately 4.5 km of NPS 20 inch High Pressure (HP) steel (ST) natural gas main on Lake Shore Boulevard from Cherry Streeet to Bathurst Street and a 260 m section on Parliament Street from Mill Street to Lake Shore Boulevard East (C2B) in the City of Toronto. The segment of pipeline to be replaced is part of the natural gas main knows as the Kipling Oshawa Loop (KOL). The pipeline is located in a densely populated downtown area of the City of Toronto where a pipeline failure could result in loss of gas distribution service for thousands of customers or in the extreme case public safety at risk. • Analysis conducted by Enbridge Gas as part of the Distribution Integrity Management Program (DIMP), asset health review of the KOL and subsequent In-Line Inspections indicated a need for

	remediation or replacement due to corrosion, dents, compression couplings and depth of cover issues. • The budget covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, overheads and interest during construction. <u>Other Options Considered</u>: • Enbridge Gas considered two options for the project. The first option was to repair issues at localized areas via integrity digs on the C2B segment of the KOL. The second option was to replace the C2B segment of the KOL. • The option to repair has the advantage of spreading capital expenditures over multiple years. However, disadvantages include the number of integrity digs required over the next 40 years, disruptions to traffic, local businesses and residents as a result of the digs. Also, existing depth of cover issues will remain, O&M costs will increase due to more frequent ILI's and there will be increased security of supply risk. • The option to replace the segment is the preferred option as it addresses and improves the entire segment of the pipeline, reduces O&M costs, reduces the probability of pipeline failure. The new asset will be constructed using modern standards and materials allowing for additional protection against and mitigation of third party damages. The NPS 20 Replacement Cherry to Bathurst was subject to a Leave to Construct application in EB-2020-0136. In this application, Enbridge Gas presented the need for the project, the alternatives considered for

	the project, the project cost and economics, environmental issues, land matters and indigenous consultation. In its Decision and Order dated December 17th, 2020, the OEB found that: • Enbridge Gas demonstrated the need for this project • Enbridge Gas considered a reasonable range of alternatives and found that the proposed project is superior to these alternatives • The project is in the public interest and is the lowest cost alternative. The OEB also found that Enbridge Gas has adequately addressed environmental issues, land matters and the procedural aspects of the duty to consult with impacted Indigenous communities. The budget of $129.9 million is updated from the EB-2020-0136 filing budget of $133.0 million. The variance between the the budget and the leave to contruct is due to a revised cost estimate and change in overhead allocations. The budget covers all costs related to material, construction and labour, land costs, contingencies, overheads, abandonment and interest during construction.

Union Rate Zones

Dawn-Cuthbert Replacement and Retrofits	
Budget: $24.2 million Projected In-Service Date: September, 2022 In-Service Capital Spend: $23.5 million 2022 in-service; $0.6 million 2023 in-service	<u>Category of Investment</u>: System Service <u>Project Description and Drivers</u>: • Replacement of approximately 650 m of the existing NPS 42 Dawn to Cuthbert pipeline located between the Cuthbert Road Measurement Station and the Trafalgar Valve Nest. The existing pipeline consists of approximately 1.1 km of NPS 42 supplying the NPS 42 Dawn to Kirkwall pipeline, which is one of four parallel pipelines that form the Dawn Parkway System. The replacement pipeline will be a like-for-like replacement matching the existing pipeline size and maximum operating pressure. In addition to the pipeline replacement, modifications are required in order to allow the passage of in-line inspection (ILI) tools for future integrity management activities. • Analysis conducted by Enbridge Gas's Transmission Integrity Management Program (TIMP) including investigative digs and External Corrosion Direct Assessments (ECDA) confirmed the presence of Stress Corrosion Cracking (SCC). Enbridge Gas has identified that the existing line is an operational risk and should be replaced to manage the safety and reliability of the natural gas distribution to the Dawn Parkway system. • The budget covers all costs related to material, construction and labour, environmental projection measures, land acquisitions, contingencies, overheads and interest during construction.

	<u>Other Options Considered</u>: Enbridge Gas considered several alternatives including monitoring the condition of the NPS 42 Dawn-Cuthbert Pipeline with an ILI tool capable of detecting SCC (EMAT), like-for-like replacement of the existing NPS 42 pipeline and replacement of the existing NPS 42 with different diameter/MOP pipeline. • The option to monitor the condition of the NPS 42 Dawn-Cuthbert with an ILI tool (EMAT) was not chosen due to the long-term Capital and O&M costs from modifying the pipeline to accept ILI tools, performing periodic EMAT and MFL inspections and subsequent integrity digs. • The option of replacement of the existing NPS 42 with a different diameter pipe was not considered to be a viable alternative. A smaller diameter pipeline would create a pressure bottleneck and the inability to provide appropriate flow to the Dawn Parkway System. A larger diameter would be beneficial for future capacity, however this would also require a similar replacement of the NPS 42 from Dawn all the way to Kirkwall. • The option of a like-for-like replacement of the existing NPS 42 Dawn-Cuthbert pipeline is the recommended option as it is the best option to manage the long-term integrity of the pipeline and completely mitigates the risk of SCC • Enbridge Gas applied the Binary Screening Criteria outlined in the approved Integrated Resource Planning Framework (EB-2020-0091) and has determined that the project does not warrant further IRPA assessment as the need/constraint occurs within the 3-year time horizon.

	More details on the need for the project, the alternatives considered for the project, the project cost and economics and project timing are provided in Appendix A to this Exhibit. The budget of $24.2M covers all costs related to material, construction and labour, land costs, contingencies, overheads, abandonment and interest during construction.

Byron Transmission Station	
Budget: $20.4 million Projected In-Service Date: August 31, 2022 In-Service Capital Spend: $20.4 million 2022 in-service;	Category of Investment: System Service Project Description and Drivers: • Full rebuild of the existing Byron Transmission Station located on Enbridge Gas-owned property within a fenced compound in the community of Byron, Ontario. The station accepts natural gas from the Dawn Parkway System and reduces or regulates pressure for distribution to the downstream systems serving London, St. Thomas and Port Stanley. • Multiple Integrity concerns were identified through an indirect heater assessment conducted by Enbridge Gas. Concerns include noise complaints, integrity of Station inlet valves and inability of the existing Station to support the long term demand of the London market beyond 2022. • The budget covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, indirect overheads, and interest during construction.

	<u>Other Options Considered</u>: Enbridge has considered several alternatives including full station rebuild of the existing Byron Transmission Station with no land acquisition, full station rebuild of the existing Station with land acquisition, partial station replacement and moving the station to a new location. • The option of a full station rebuild with no land acquisition was not deemed feasible as the existing site was not large enough to construct the new asset while keeping the existing Station in service • The option of a partial replacement of the station was not deemed feasible as the construction duration was too long to accommodate the Station shut down without impacting security of supply. This alternative also does not address the noise, maintenance and operational concerns. • The option of moving the station to a new location would address the noise, maintenance and operational concerns, however this would also require main extensions and would increase the cost of the project. • The option of a complete station replacement with new land acquisition adjacent to the Enbridge Gas-owned lands is the preferred option as it addresses all integrity concerns. Completion of the project during summer months will mitigate risk surrounding security of supply. • At the time of project development, the OEB had not yet established an IRP Framework for Enbridge Gas. Given the timing of project development and the fact that the project is

	primarily to addresses station integrity, no formal IRP assessment was completed for this project. More details on the need for the project, the alternatives considered for the project, the project cost and economics, and project timing are provided in Appendix B to this Exhibit. The budget of $20.4M covers all costs related to material, construction and labour, land costs, contingencies, overheads, and interest during construction.

Kirkland Lake Lateral Replacement	
Budget: $20.7 million Projected In-Service Date: November, 2022 In-Service Capital Spend: $20.7 million 2022 in-service;	Category of Investment: System Renewal Project Description and Drivers: • Replacement of 8 km of NPS 4 pipeline running trough the Municipality of Kirkland Lake. The current system includes two lines, the NPS 4 Kirkland Lake Lateral and the NPS 8 Kirkland Lake Loop. Both lines primarily feed 3,126 customers in the towns of Kirkland Lake, Chaput Hughes, Swastika and the Macassa Mines. • Analysis conducted by Enbridge Gas as part of the Transmission Integrity Management Program (TIMP) and External Corrosion Direct Assessments (ECDA) inspections have indicated that the pipeline is in poor condition, has reached the end of its useful life, and should be replaced.

	• The budget covers all costs related to material, construction and labour, environmental protection measures, land acquisitions, contingencies, indirect overheads, and interest during construction. Other Options Considered: • Enbridge Gas considered several alternatives including replacing the entire 12 km of NPS 4 Kirkland Lake Lateral pipeline with NPS 6 pipeline, a like-for-like replacement of 8 km of NPS 4 Kirkland Lake Lateral pipeline and continuing to maintain the existing pipeline and repair all required indications. • The option of replacing the entire 12 km of NPS 4 Kirkland Lake Lateral was explored to accommodate expected growth with Macassa Mines as well as future demand in Kirkland Lake. The option was deemed unnecessary as Enbridge Gas was able to establish a contracted agreement with TCPL for an increased minimum inlet pressure. • The option of continuing to maintain the existing pipeline and repair all required indications had a higher NPV than the option of a like-for-like pipeline replacement. • The option of replacing 8 km of the existing 12 km pipeline is the preferred option and is the most effective way of ensuring the continued safe and reliable delivery of natural gas services to customers • Enbridge Gas applied the Binary Screening Criteria outlined in the approved Integrated Resource Planning Framework (EB-2020-0091) and has determined that the project does not warrant further IRPA assessment as the need/constraint occurs within the 3-year time horizon.

	More details on the need for the project, the alternatives considered for the project, the project cost and economics, and project timing are provided in Appendix C to this Exhibit. The budget of $20.7M covers all costs related to material, construction and labour, land costs, contingencies, overheads, and interest during construction.

Business Case:

Dawn-Cuthbert NPS 42 Replacement and Retrofits

EXHIBIT LIST

PROJECT NEED

Introduction

1. Enbridge Gas Inc. ("Enbridge Gas" or the "Company") has identified the need to replace approximately 650 m of the existing Nominal Pipe Size ("NPS") 42 inch steel ("ST") Dawn to Cuthbert pipeline to mitigate pipeline integrity concerns. The Dawn to Cuthbert NPS 42 Replacement Project ("Project") will replace a portion of the existing pipeline which runs through the Township of Dawn-Euphemia, in the County of Lambton, Ontario. A map of the Project is provided as Attachment 1 to this Exhibit.

2. The existing Dawn to Cuthbert pipeline consists of approximately 1.1 km of NPS 42 ST pipeline running in an easement paralleling two adjacent NPS 26/30 and NPS 34/30 ST pipelines. It operates above 30% of the specified minimum yield strength ("SMYS"). The pipeline was originally constructed in 1975, and a 500 m segment of the pipeline between the Trafalgar Valve Nest and the Dawn South Yard was replaced in 1995. The Project consists of approximately 650 m of NPS 42 ST pipeline located between the Cuthbert Road Measurement Station and the Trafalgar Valve Nest.

3. The NPS 42 Dawn to Cuthbert pipeline supplies the NPS 42 Dawn to Kirkwall pipeline, which is one of four parallel pipelines that form the Dawn Parkway System. The Dawn Parkway System is the backbone gas transmission system that serves the demands of millions of customers located in Ontario, Quebec, Eastern Canada and the U.S. Northeast. A map of the Dawn Parkway System is shown as Attachment 2 to this Exhibit.

4. The replacement pipeline will be like-for-like replacement, matching the existing pipeline size and maximum operating pressure of 6,160 kPag (893 psig).

5. In addition to the pipeline replacement, modifications are required in order to allow the passage of in-line inspection ("ILI") tools for future integrity management activities.

6. The modifications consist of relocating below ground piping to above ground to permit the insertion and removal of ILI tools, and replacing pipeline appurtenances that cannot be traversed by ILI tools.

Project Need

7. Canadian Standards Association Standard Z662 ("CSA Z662") provides guidance on when a pipeline operator should address pipeline integrity and condition concerns. It is the responsibility of the pipeline operator to monitor the condition of its pipeline assets and compare the condition of those assets to the guidance set out in CSA Z662. Should the condition of a pipeline be such that it creates a risk pursuant to CSA Z662 guidance, the pipeline operator must address the condition of the pipeline. Enbridge Gas's Transmission Integrity Management Program ("TIMP") periodically evaluates assets to identify hazards and determine the condition and risk of pipelines in the transmission network. An integrity assessment was recently conducted on the NPS 42 Dawn to Cuthbert pipeline as part of the scheduled condition monitoring program. The integrity assessment confirmed that the pipeline coating has degraded, allowing for the formation of time dependent pipeline threats which cannot reliably be detected using condition monitoring methods available on this pipeline. Enbridge Gas has determined that the pipeline condition represents an intolerable risk, to be mitigated through replacement of the 650 m segment of the Dawn to Cuthbert pipeline.

Condition of the Existing Pipeline

8. The NPS 42 Dawn to Cuthbert pipeline was constructed in 1975 and consistent with construction standards at that time was coated with polyken tape. This coating has degraded over the life of the pipeline, resulting in adhesive disbondment. Disbonded tape coatings prevent electric cathodic protection current from reaching the pipe surface, and trap electrolytes between the pipe surface and the coating. This creates ideal conditions for external corrosion and Stress Corrosion Cracking ("SCC"), as the cathodic protection system is ineffective in protecting the pipeline steel.

Integrity Digs

9. Five investigative integrity digs have been completed between 2001 and 2019. Results of the integrity digs can be found in Attachments 3 to 7 of this Exhibit. The integrity digs have confirmed the presence of disbonded polyken tape coating, active external corrosion, and/or SCC on segments of the Dawn to Cuthbert pipeline.

External Corrosion Direct Assessments and Stress Corrosion Cracking Direct Assessments

10. In addition to the integrity digs, an External Corrosion Direct Assessment ("ECDA") survey was performed in 2005 and 2020 by third party consultants. These surveys can be found at Attachments 8 to 9 of this Exhibit. A Stress Corrosion Cracking Direct Assessment ("SCCDA") survey was also performed in 2001 as part of the integrity dig, discussed above. As outlined in each of the ECDA surveys, the presence of an electrically shielded coating limits the effectiveness of an ECDA program to detect corrosion activity at locations of disbonded polyken tape coating, which is also creates an environment conducive to the formation and growth of SCC.

Alternative Integrity Assessments

11. Due to the cathodic protection shielding effect of disbonded polyken tape, recognized condition monitoring techniques such as ECDA or SCCDA are not reliable to locate areas of the pipeline that are likely to contain external corrosion or SCC. As a result, it is not possible to reliably detect the most severe external corrosion or SCC features via these available condition monitoring techniques. Another condition monitoring technique used to detect SCC in natural gas pipelines is an ILI technology known as Electromagnetic Acoustic Transducer (“EMAT”). Disbonded polyken tape coatings do not have an effect on the reliability of EMAT.

12. Pipelines with modern external pipeline coatings that are not susceptible to SCC typically do not require monitoring using EMAT ILI tools. Instead, they can be adequately inspected through the use of lower cost tools such as caliper and Magnetic Flux Leakage tools (“MFL”), which is industry best practice and accepted as the required level of diligence for condition monitoring of pipelines operated above 30% SMYS.

13. Some downstream segments of the NPS 42 Dawn to Kirkwall portion of the Dawn Parkway System were constructed at the same time and with the same materials as the NPS 42 Dawn to Cuthbert pipeline, including polyken tape coating. These segments have been monitored closely through in-line inspections, targeted integrity dig programs and engineering analysis to quantify the severity and growth rates of these pipeline threats. The NPS 42 Dawn to Cuthbert pipeline, however, does not currently have ILI tool launching and receiving facilities to permit any ILI tools, including ones capable of detecting SCC.

Corrosion

14. External corrosion resulting in wall loss has been confirmed on the existing pipeline through investigative integrity digs. The shielding effect of the pipeline coating prevents the cathodic protection system from protecting the pipeline steel, which would otherwise mitigate against external corrosion.

15. Investigative dig site locations cannot reliably predict where corrosion is likely to occur. This is a result of shielding of the cathodic protection system due to the disbondenment of the vintage coating. A typical ECDA program recommends dig sites based on changes in cathodic protection levels in conjunction with instances of coating damage, which exposes pipeline steel to the surrounding environment and creates a favourable environment for external corrosion. If the coating is disbonded, this prevents the close interval potential survey ("CIPS") from accurately representing the level of cathodic protection. Therefore, it is not possible to confidently select dig sites that are likely to have the least amount of cathodic protection and highest likelihood of corrosion. Figures 2 and 3 below describe the similar state of external corrosion observed on the Dawn to Cuthbert pipeline to the NPS 42 Dawn to Kirkwall pipeline.

Figure 2: Dawn to Cuthbert Corrosion (2005)

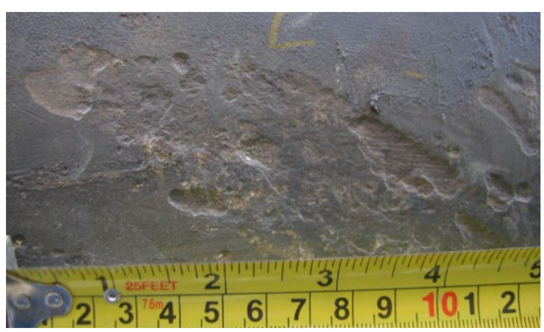
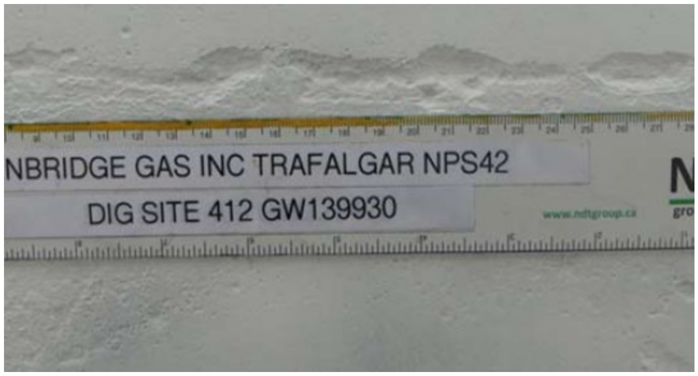


Figure 3: Typical NPS 42 Dawn to Kirkwall Corrosion (2019)



Stress Corrosion Cracking

16. SCC has been confirmed to be active on the NPS 42 Dawn to Cuthbert pipeline through investigative digs in both the pipeline body and along the toe of the longseam weld. The shielding effect of the pipeline coating coupled with specific environmental conditions have created the ideal environment conducive to SCC. SCC is a time-dependent threat that grows in severity over time, due to the combination of pipeline operating hoop stress, susceptible material and environmental condition.

17. Based on the inspection methodologies used, it could not be determined whether the most severe SCC features have been discovered on the Dawn to Cuthbert segment and as a result, it is imperative that mitigative action be taken to proactively manage this critical asset.

18. The environmental, operational and material conditions of the uninspected NPS 42 Dawn to Cuthbert segment are similar to the NPS 42 Dawn to Kirkwall segment. SCC discovered on the Dawn to Kirkwall segment that is inspected using ILI tools provides a more reliable representation of the pipelines' integrity compared to the SCC discovered on the NPS 42 Dawn to Cuthbert segment through investigative digs, ECDA and SCCDA, and as such enables Enbridge Gas to make more

informed integrity decisions. This inference is exemplified in Figures 4 through 7, comparing the integrity dig data of the existing line to the integrity dig data available on the NPS 42 Dawn to Kirkwall segment that is inspected with EMAT. The non-destructive examination results on the NPS 42 Dawn to Cuthbert segment are detailed in Attachments 3 to 9 of this Exhibit.

Figure 4: NPS 42 Dawn to Cuthbert Disbonded Polyken Tape Coating (2005)

Figure 5: Typical Trafalger NPS 42 Dawn to Kirkwall Disbonded Polykin Tape

Figure 6: NPS 42 Dawn to Cuthbert Toe Cracking SCC (2019)

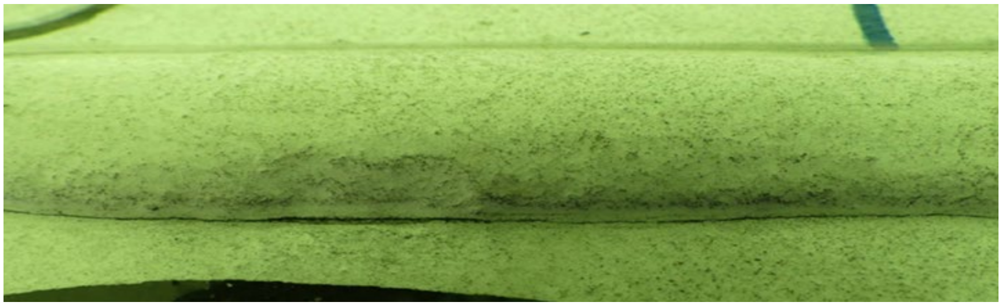


Figure 7: Typical Trafalgar NPS 42 Dawn to Kirkwall Toe Cracking SCC (2020)

Consequence of a Failure

19. In the event of a failure of the NPS 42 Dawn to Cuthbert pipeline, emergency operations would isolate the pipeline along with the adjacent NPS 26 and 34 pipelines that parallel in close proximity. Under this condition, the only pipeline leaving the Dawn Compressor Station facility to serve the Dawn Parkway System would be the NPS 48 Dawn to Parkway pipeline. This creates a capacity restriction in the 15 km segment between the Dawn Compressor Station and the Enniskillen Valve Site.

20. In the winter, gas is shipped easterly from Dawn to Parkway. A failure event on the NPS 42 Dawn to Cuthbert pipeline would limit capacity on the Dawn Parkway System for the first 15 km from the Dawn Compressor Station, resulting in a 30% reduction in peak sendout. A reduction of this magnitude would require a 30% demand reduction from all firm customers, including residential, commercial,

industrial and power generation facilities, as well as the isolation of multiple sections of large cities in Ontario. Ex-franchise customers in Quebec, Eastern Canada and parts of the U.S. North East would also be curtailed.

21. In the summer, gas is typically shipped westerly from Parkway to Dawn. The NPS 48 Dawn to Parkway pipeline is capable of supporting normal market needs outside of the heating season. However, the capacity restriction that would be in effect between the Enniskillen Valve Site and the Dawn Compresor Station compromises the ability for Enbridge Gas to control gas pipeline pressures into specific markets during integrity maintenance activities. Maintenance activities such as integrity digs typically require line pressure to be reduced to accommodate safe excavation of pipeline anomalies under investigation. Furthermore, integrity inspections that are required as part of the Enbridge Gas Integrity Management Plan on any of the adjacent Dawn Parkway System pipelines requires the manipulation of gas flow in order to push or pull ILI tools through pipelines. Isolation of the NPS 42 Dawn to Cuthbert pipeline and adjacent NPS 26 and NPS 34 during a failure prevents these activities from taking place until the failure event is rectified.

22. The storage injection operations into various Enbridge Gas pools, including Edys Mills, Oil City and Oil Springs East, depend on the operation of the NPS 42 Dawn to Cuthbert pipeline and adjacent Dawn Parkway System pipelines. These storage pools account for approximately 2.9% of the total storage capacity at Dawn. During a failure event, the capacity restriction created by isolating the NPS 26, 34 and 42 pipelines between Dawn and Cuthbert would prevent storage injection operations from proceeding.

Recommendation for Pipeline Replacement

23. In addition to the guidance on Integrity Management Programs in CSA Z662, the Canada Energy Pipeline Association ("CEPA") documents guidance for pipeline operators experiencing SCC in the *CEPA Recommended Practices for Managing Near-Neutral Stress Corrosion Cracking, 3rd Edition*. Depending on the severity of the SCC, various mitigation activities are recommended including, but not limited to, inspecting the pipeline with an ILI tool capable of detecting SCC (e.g. EMAT), restriction of operating pressure, 100% surface non-destructive testing or pipe segment replacement.

24. An analysis of pipe replacement versus EMAT ILI and subsequent integrity digs concluded that pipeline replacement provided the most certainty regarding risk reduction, had less economic variability and was the least expensive option over a 40 year horizon. This is described further in Exhibit C, Tab 1, Schedule 1. Replacement of the NPS 42 Dawn to Cuthbert pipeline with new pipeline that completely mitigates the threat of SCC has a more substantial reduction of risk and better enhances the safety and reliability of the pipeline compared to continued inspections of the existing pipeline.

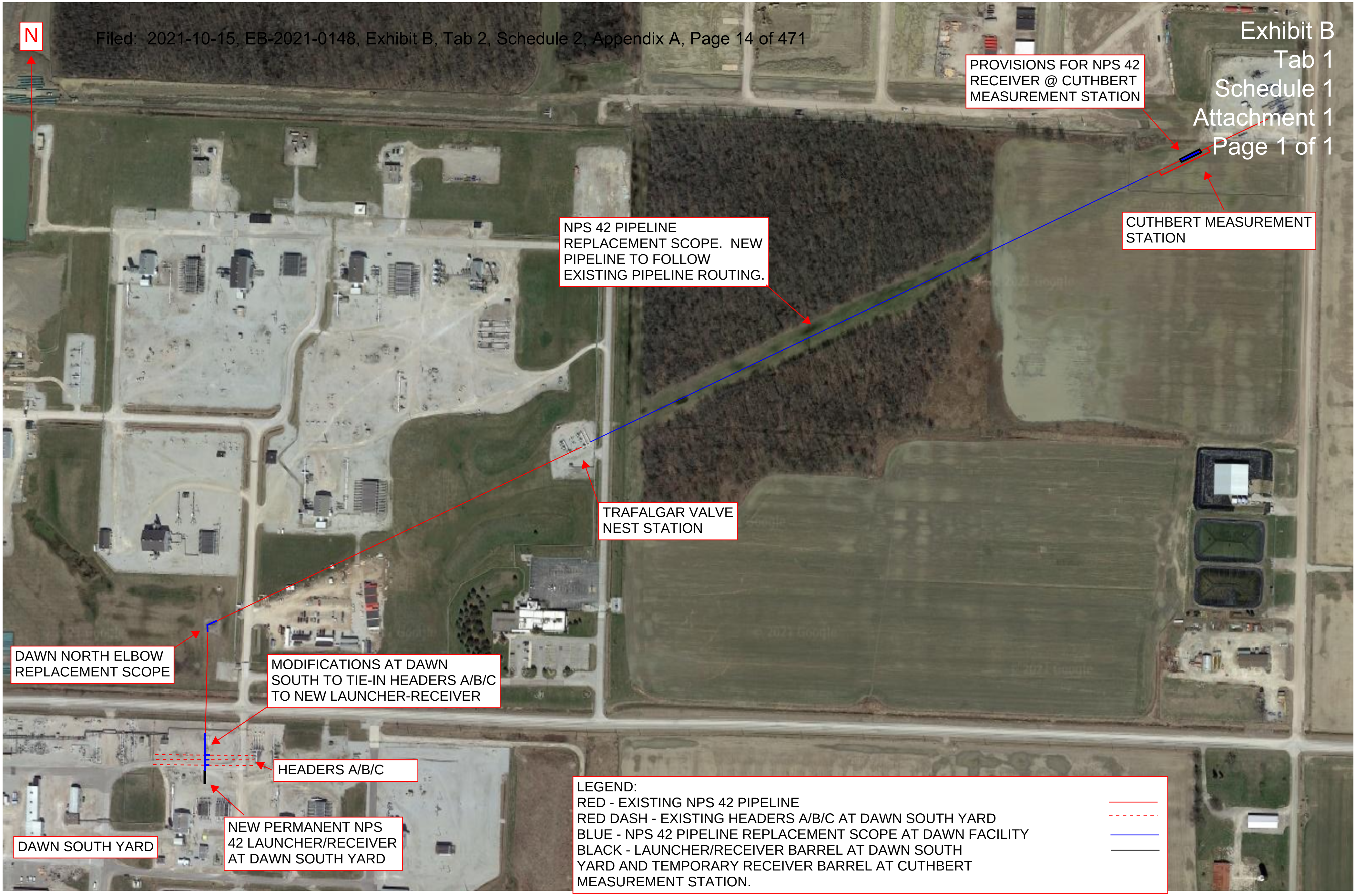
ILI Capability

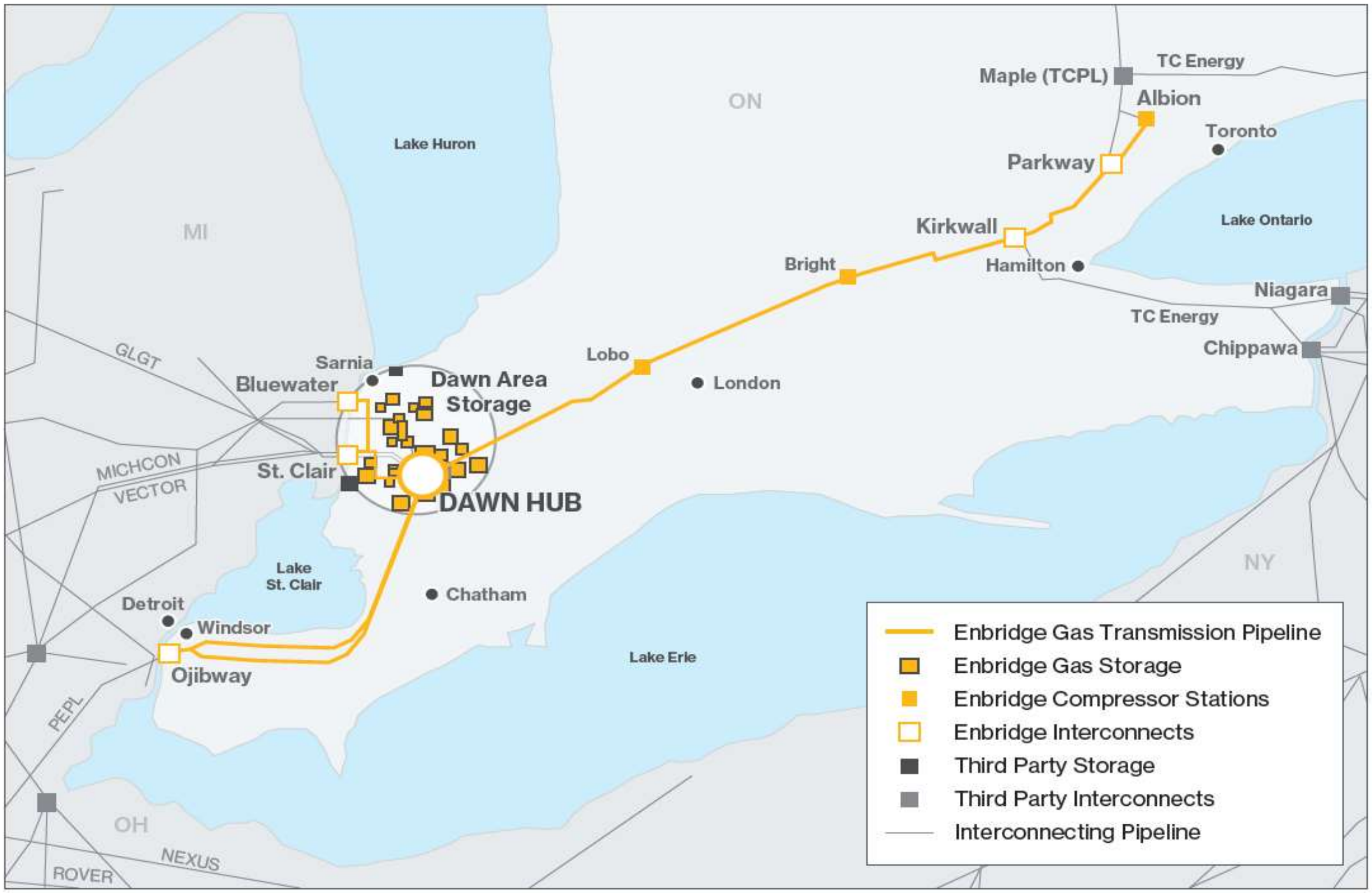
25. Constructing a replacement pipeline with modern coating alleviates the threat of SCC and as a result, does not require ILI using specialized EMAT technology. However, it does not alleviate the responsibility Enbridge Gas has to monitor the condition of the pipeline. To take advantage of construction synergies during the replacement work, the Project will also include modification of the NPS 42 Dawn to Cuthbert pipeline to allow condition monitoring with ILI, which is a more informative and reliable condition monitoring technique than ECDA or SCCDA. Examples of pipeline hazards that can be detected through ILI but not through ECDA and SCCDA include, but are not limited to, internal metal loss, pipeline damage (e.g. deformation), and manufacturing and construction anomalies. Compared to

ECDA and SCCDA, ILI results provide a more detailed understanding of pipeline condition, which enables more informed decision making.

Project Schedule

26. The Project schedule is provided as Attachment 10 to this Exibit.


N
PROVISIONS FOR NPS 42 RECEIVER @ CUTHBERT MEASUREMENT STATION
CUTHBERT MEASUREMENT STATION
NPS 42 PIPELINE REPLACEMENT SCOPE. NEW PIPELINE TO FOLLOW EXISTING PIPELINE ROUTING.
TRAFALGAR VALVE NEST STATION
DAWN NORTH ELBOW REPLACEMENT SCOPE
MODIFICATIONS AT DAWN SOUTH TO TIE-IN HEADERS A/B/C TO NEW LAUNCHER-RECEIVER
HEADERS A/B/C
NEW PERMANENT NPS 42 LAUNCHER/RECEIVER AT DAWN SOUTH YARD
DAWN SOUTH YARD
LEGEND:
RED - EXISTING NPS 42 PIPELINE
RED DASH - EXISTING HEADERS A/B/C AT DAWN SOUTH YARD
BLUE - NPS 42 PIPELINE REPLACEMENT SCOPE AT DAWN FACILITY
BLACK - LAUNCHER/RECEIVER BARREL AT DAWN SOUTH YARD AND TEMPORARY RECEIVER BARREL AT CUTHBERT MEASUREMENT STATION.



ENBRIDGE
Life Takes Energy

SITE REPORT

Union Gas

Project: Summer 2001 Dig Program

Dig Site No.: 111 (Dawn)

Excavation Summary

The condition of the original poly tape coating at this excavation location was found to be in poor condition with consistent wrinkles at the three, twelve and nine o'clock positions. As well, tenting at the girth welds and long seams was present as is typical of poly tape. Some corrosion deposits were present beneath the coating mostly at the weld locations. Magnetic particle inspection was performed on all girth welds, long seams and disbondments as indicated in our final report. The section of pipe between girth welds two and three was inspected with M.P.I one hundred percent 360*. This inspection of joint # 2 included the bottom six o'clock position commonly susceptible to corrosion. No indication of stress corrosion cracking was found within the areas inspected at this excavation location. During the process of removing excess coating while reblasting for the epoxy recoat some pitting was detected that was not within the original inspection area. This corrosion was documented as corrosion area number six and determined to be within the acceptable axial length for the measured maximum depth of 1.7mm.

Project Information

Project Manager:	Michael C. Crutchley	**Code No:**	CSA Z662-99
Contract No:		**RTD Job No:**	100361
RTD Procedure No:	PI-001 Thru PI-009	**Reviewed By:**	Andre Filiatrault
NDE Contractor:	RTD Quality Services	**Junior Inspector:**	Mark Mahussier
Excavation Contractor:	Douglas & Kozera	**Senior Inspector:**	Rob Squair

Union Gas

Project Name: **Summer 2001 Dig Program** **Dig Site No.:** 111 (Dawn)

Site Information

Date:	August 27, 2001	**Chainage of Reference:**	62 m	**Operating Zone:**	Dawn
Control Point Description:	Compressor Station	**Cell:**	No	**Property Owner:**	Lourie
Chainage:	62.2 m	**Reason for Excavation:**	Other	**Dist. to U/S Comp/Pump:**	62.20m
GPS Coordinate of:	Reference Point	**Areas to be Inspected:**	Weld Seams, Disbondments, Full Circumference	**MLV:**	Dawn **To MLV:** Lobo
Zone:				**Line No. or Name:**	Trafalgar
Northing:		**Excavation Type:**	SCC	**Fluid Type:**	Natural Gas
Easting:		**Predicted SCC Susceptibility:**	Moderate	**Fluid Phase:**	Gas
Elevation:		**Alignment Sheet No.:**		**Fluid Sour:**	No
Control to Reference:	62.20m	**Legal Description:**	Lot119, Con1, Dawn Tsp.	**KM Post:**	0
Reference Description:	G.W.	**Location Class:**	1	**Section No.:**	
		Station No.:	Dawn		
Log Amplitude:		**ILI Technology:**		**ILI Absolute Odometer:**	

Pipe Information

Pipe OD:	1066.8mm	**Year Manufactured:**	1982	**Site MAOP:**	6,160 kPa
Nominal Wall Thickness:	11.20mm	**Pipe Installed Year:**	1982	**Currrent Op. Stress:**	80.00 % SMYS
Grade:	Gr. 448	**Pipe Manufacturer:**	Stelco	**Maximum Stress:**	80.00 % SMYS

Topography Information

Excavation Size Start:	-500.0cm	**Topography:**	Undulating	**Land Use:**	Cultivated
Excavation Size End:	5,200.0cm	**Topographic Category 1:**	Sedimentary Cover	**Site Position:**	Depression
Physiographic Region:	St. Lawrence LowLands	**Topographic Category 2:**	Hill and Low Tablelands	**Adjacent Slopes:**	
Vegetative Landform:	Boreal	**Topographic Category 3:**	Non-Glaciated Area		

Soil Information

				SOIL TEXTURE (cm)					STRATIFICATION DEPTHS (cm)						RESISTIVITY				
Depth of Cover	Pipe Clearance	Drainage	Soil Deposition	Start	End	Depth	Thickness	Soil Texture	Mottling	Gleying	Organic	Carbonate	Bedrock	H20 Table	Resistivity Type	Axial Distance	Resistivity Ohms/cm	Centerline Distance	Reading Date
120.00cm	75.00cm	Imperfect	Lacustrine	-125	4,805	30.00	302.00	Clay, Sand			30								

Soil/Water Sample Information

All corrosion product deposits and cathodic protection product samples were found to be to dry to provide a PH reading.

None found at time of inspection.

Union Gas

Project Name: **Summer 2001 Dig Program** **Dig Site No.:** 111 (Dawn)

External Coating Condition Information

Coating Over: G.W. and Pipe **Start: -125cm** **End: 4,805cm**

Coating Type: Poly Tape
Brand: Polyken
Application: Line
Wraps: Single

Condition: Poor
Season:
Year Applied:
Primer: Yes

Tape Primer:
Wrapper:
Condition:

COATING THICKNESS:
Average:
Top:
Bottom:
Side:

Holiday Information

Holiday No.	Axial Distance	Length	Width	Circ. Length	Orientation	Distance From TDC	Holiday Tester	Deposit
Hol1	190.00cm	22.00cm	22.00cm	22.00cm	0°	-50.00cm	No	Yes

HOLIDAY DEPOSITS

Hol1-1 **Deposit Type: Cathodic Deposit**

Axial Distance: 190.00cm **Width:** 22.00cm **Dist. From TDC:** -50.00cm **Colour:** White, Grey

Disbondment Information

Disbondment No.	Ax. Dist. from Ref.	Disb. Type	Disbondment Condition	Percent Disb.	Axial Length	Width	Circ. Length	Distance From TDC	Orient.	Under Disb.	TENT MEASUREMENTS (cm) Direction	LongSeam	Meas.	Deposit
Dis1	-75.00cm	Wrinkle	Fair	60 %	82.00cm	115.00cm	115.00cm	60.00cm	0°	Dry				Yes
Dis2	650.00cm	Wrinkle	Poor	70 %	105.00cm	105.00cm	105.00cm	-20.00cm	0°	Dry				Yes
Dis3	815.00cm	Wrinkle	Poor	65 %	46.00cm	46.00cm	46.00cm	5.00cm	0°	Dry				Yes
Dis4	2,165.00cm	Wrinkle	Poor	50 %	220.00cm	120.00cm	120.00cm	100.00cm	0°	Dry				Yes
Dis5	3,814.00cm	Wrinkle	Poor	50 %	140.00cm	140.00cm	140.00cm	10.00cm	0°	Dry				Yes
Dis6	3,550.00cm	Wrinkle	Poor	50 %	40.00cm	70.00cm	70.00cm	-164.00cm	0°	Dry				Yes

DISBONDMENT DEPOSITS

Union Gas

Project Name: **Summer 2001 Dig Program** **Dig Site No.:** 111 (Dawn)

Dis1-1 Deposit Type: Corrosion

Axial Distance:	-75.00cm	**Width:**	115.00cm	**Dist. From TDC:**	60.00cm	**Colour:**	White, Brown, Black
Axial Length:	82.00cm	**Circ. Length:**	115.00cm	**Distribution:**	Intermittent	**Texture Type:**	Scaly, Powdery, Hard
MIC:				**SRB:**		**HCL:**	

Dis2-1 Deposit Type: Corrosion

Axial Distance:	650.00cm	**Width:**	105.00cm	**Dist. From TDC:**	-20.00cm	**Colour:**	White, Brown, Black
Axial Length:	105.00cm	**Circ. Length:**	105.00cm	**Distribution:**	Intermittent	**Texture Type:**	Scaly, Powdery, Hard
MIC:				**SRB:**		**HCL:**	

Dis3-1 Deposit Type: Corrosion

Axial Distance:	815.00cm	**Width:**	46.00cm	**Dist. From TDC:**	5.00cm	**Colour:**	Orange, Brown, Black
Axial Length:	46.00cm	**Circ. Length:**	46.00cm	**Distribution:**	Intermittent	**Texture Type:**	Scaly, Powdery, Hard
MIC:				**SRB:**		**HCL:**	

Dis4-1 Deposit Type: Corrosion

Axial Distance:	2,165.00cm	**Width:**	120.00cm	**Dist. From TDC:**	100.00cm	**Colour:**	White, Brown, Black
Axial Length:	220.00cm	**Circ. Length:**	120.00cm	**Distribution:**	Intermittent	**Texture Type:**	Scaly, Powdery, Hard
MIC:				**SRB:**		**HCL:**	

Dis5-1 Deposit Type: Corrosion

Axial Distance:	3,814.00cm	**Width:**	140.00cm	**Dist. From TDC:**	10.00cm	**Colour:**	White, Brown, Black
Axial Length:	140.00cm	**Circ. Length:**	140.00cm	**Distribution:**	Intermittent	**Texture Type:**	Scaly, Powdery, Hard
MIC:				**SRB:**		**HCL:**	

Dis6-1 Deposit Type: Corrosion

Axial Distance:	3,550.00cm	**Width:**	70.00cm	**Dist. From TDC:**	-164.00cm	**Colour:**	Orange, White, Brown, Black
Axial Length:	40.00cm	**Circ. Length:**	70.00cm	**Distribution:**	Intermittent	**Texture Type:**	Scaly, Powdery, Hard
MIC:				**SRB:**		**HCL:**	

External Pipe Information

PIPE IDENTIFICATIONS

X Ray No.	Upstream Joint Length	Upstream Heat No.	Downstream Joint Length	Downstream Heat No.
			11.31m	

RTD QUALITY SERVICES

Union Gas

Project Name: **Summer 2001 Dig Program** **Dig Site No.:** 111 (Dawn)

CP and TEMP

Axial Distance	Pipe to Soil Potential	CP	Pipe Temperature
0.00cm	-1,480.00mV	On	21.00°C

PIPE PARAMETERS

	Start	End
Exposed	-125.00cm	4,805.00cm
Bare	-120.00cm	4,792.00cm

NDE SURFACE PREP

Blast Type	Pressure	Surface Finish	Brand Name	Surface Profile	Nozzle Size	Methanol Wash
Abrasive	100 - 120 psi	NACE 3	K&E White Lightning	1 - 2 mils	7	No

Pipe Welds and Seams

Girth Weld No.: GW-01

		UT WALL THICKNESS				UPSTREAM SEAM		DOWNSTREAM SEAM	
Distance To Ref.:	0.00cm	**3:00 U/S:**	11.30 mm	**9:00 U/S:**	11.10 mm	**Seam Type:**	Long Seam	**Seam Type:**	Long Seam
Type:	Field	**3:00 D/S:**	11.10 mm	**9:00 D/S:**	11.10 mm	**Weld Process:**	DSAW	**Weld Process:**	DSAW
Welding Process:	SMAW	**6:00 U/S:**	11.30 mm	**12:00 U/S:**	11.30 mm	**Distance From TDC:**	-35.00cm	**Distance from TDC:**	45.00cm
Height Of Weld Cap:	2.00mm	**6:00 D/S:**	11.20 mm	**12:00 D/S:**	11.00 mm	**Height Of Weld Cap:**	3.00mm	**Height Of Weld Cap:**	3.00mm

Girth Weld No.: GW-02

		UT WALL THICKNESS				UPSTREAM SEAM		DOWNSTREAM SEAM	
Distance To Ref.:	1,131.00cm	**3:00 U/S:**	11.10 mm	**9:00 U/S:**	11.00 mm	**Seam Type:**	Long Seam	**Seam Type:**	Long Seam
Type:	Field	**3:00 D/S:**	11.30 mm	**9:00 D/S:**	11.20 mm	**Weld Process:**	DSAW	**Weld Process:**	DSAW
Welding Process:	SMAW	**6:00 U/S:**	11.00 mm	**12:00 U/S:**	11.10 mm	**Distance From TDC:**	45.00cm	**Distance from TDC:**	-40.00cm
Height Of Weld Cap:	2.00mm	**6:00 D/S:**	11.30 mm	**12:00 D/S:**	11.30 mm	**Height Of Weld Cap:**	3.00mm	**Height Of Weld Cap:**	3.00mm

Girth Weld No.: GW-03

		UT WALL THICKNESS				UPSTREAM SEAM		DOWNSTREAM SEAM	
Distance To Ref.:	2,274.00cm	**3:00 U/S:**	11.20 mm	**9:00 U/S:**	11.30 mm	**Seam Type:**	Long Seam	**Seam Type:**	Long Seam
Type:	Field	**3:00 D/S:**	11.40 mm	**9:00 D/S:**	11.30 mm	**Weld Process:**	DSAW	**Weld Process:**	DSAW
Welding Process:	SMAW	**6:00 U/S:**	11.20 mm	**12:00 U/S:**	11.20 mm	**Distance From TDC:**	-40.00cm	**Distance from TDC:**	30.00cm
Height Of Weld Cap:	2.00mm	**6:00 D/S:**	11.30 mm	**12:00 D/S:**	11.40 mm	**Height Of Weld Cap:**	3.00mm	**Height Of Weld Cap:**	3.00mm

Girth Weld No.: GW-04

Union Gas

Project Name: **Summer 2001 Dig Program** **Dig Site No.:** 111 (Dawn)

		UT WALL THICKNESS				UPSTREAM SEAM		DOWNSTREAM SEAM	
Distance To Ref.:	3,429.00cm	**3:00 U/S:**	11.30 mm	**9:00 U/S:**	11.30 mm	**Seam Type:**	Long Seam	**Seam Type:**	Long Seam
Type:	Field	**3:00 D/S:**	11.30 mm	**9:00 D/S:**	11.10 mm	**Weld Process:**	DSAW	**Weld Process:**	DSAW
Welding Process:	SMAW	**6:00 U/S:**	11.40 mm	**12:00 U/S:**	11.20 mm	**Distance From TDC:**	30.00cm	**Distance from TDC:**	-50.00cm
Height Of Weld Cap:	2.00mm	**6:00 D/S:**	11.30 mm	**12:00 D/S:**	11.30 mm	**Height Of Weld Cap:**	3.00mm	**Height Of Weld Cap:**	3.00mm

Girth Weld No.: GW-05

		UT WALL THICKNESS				UPSTREAM SEAM		DOWNSTREAM SEAM	
Distance To Ref.:	4,583.00cm	**3:00 U/S:**	11.10 mm	**9:00 U/S:**	11.10 mm	**Seam Type:**	Long Seam	**Seam Type:**	Long Seam
Type:	Field	**3:00 D/S:**	10.80 mm	**9:00 D/S:**	11.00 mm	**Weld Process:**	DSAW	**Weld Process:**	DSAW
Welding Process:	SMAW	**6:00 U/S:**	11.10 mm	**12:00 U/S:**	11.00 mm	**Distance From TDC:**	-50.00cm	**Distance from TDC:**	20.00cm
Height Of Weld Cap:	2.00mm	**6:00 D/S:**	11.00 mm	**12:00 D/S:**	10.90 mm	**Height Of Weld Cap:**	3.00mm	**Height Of Weld Cap:**	3.00mm

Mechanical Damage

None found at time of inspection.

Volumetric Anomalies

Anomaly ID	Anomaly Type	Anomaly Extent	Axial Distance	Axial Length	Orient.	Width	Circ. Length	Distance From TDC	Average Depth	Maximum Depth	REMAINING WALL (mm) Minimum	REMAINING WALL (mm) Average	Actual Wall Thk.	Anomaly Location	Repair	Evaluation Method
C-01	Corrosion	Pitting	642.00cm	2.00cm	0°	2.00cm	2.00cm	47.00cm	0.80mm	1.30mm	9.90	10.40	11.20mm	External	No	Pit Gauge, UT A Scan
C-02	Corrosion	Pitting	975.00cm	22.00cm	0°	4.00cm	4.00cm	48.00cm	0.40mm	0.80mm	10.40	10.80	11.20mm	External	No	Pit Gauge, UT A Scan
C-03	Corrosion	Pitting	2,157.00cm	4.00cm	0°	2.00cm	2.00cm	62.00cm	0.70mm	1.20mm	10.00	10.50	11.20mm	External	No	Pit Gauge, UT A Scan
C-04	Corrosion	Pitting	2,265.00cm	7.50cm	0°	6.50cm	6.50cm	-66.00cm	0.60mm	1.40mm	9.80	10.60	11.20mm	External	No	Pit Gauge, UT A Scan
C-05	Corrosion	Pitting	3,717.00cm	5.00cm	0°	2.00cm	2.00cm	-52.00cm	0.70mm	1.15mm	10.05	10.50	11.20mm	External	No	Pit Gauge, UT A Scan
C-06	Corrosion	Pitting	3,535.00cm	42.00cm	0°	42.00cm	30.00cm	-163.00cm	0.80mm	1.70mm	9.50	10.40	11.20mm	External	No	UT A Scan, UT Pen Probe

Linear Anomalies

None found at time of inspection.

Repairs

No repairs required.

Recoating

RECOATING

Coating Over: G.W. and Pipe
Coating Brand: SPC 2888
Rock Shield: No
Primer Used: No
Start:
Type: Epoxy Urethane
Ambient Temp.:
Dew Point:
Recoat Tape Primer:
End:
Application: Brush
Pipe Temp.:
% of Rel. Humidity:
Recoat Tape Wraps: NA

SURFACE PREPARATION INFORMATION (FOR RECOATING)

Blast Type: Abrasive Blast
Pressure: 100 - 120psi
Brand Name: Black Beauty
Surface Profile: 3 - 4mils
Nozzle Size: 5
Surface Finish: NACE 2
Methanol Wash: Yes

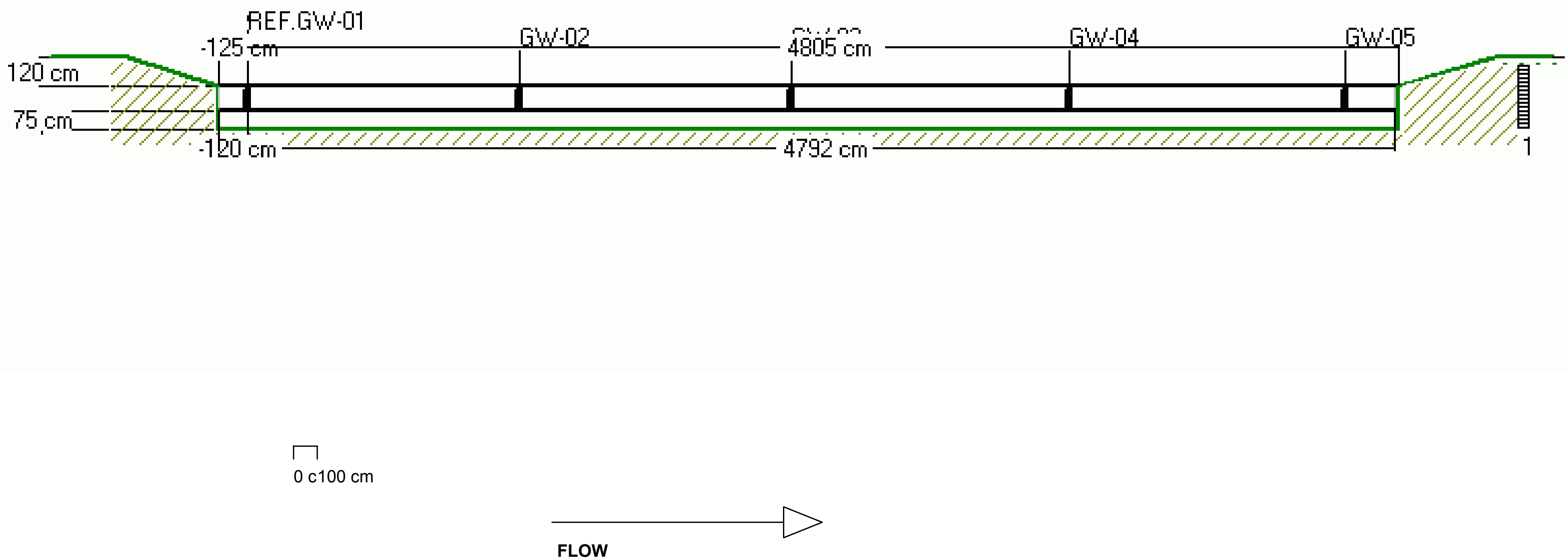
BACKFILL INFORMATION

Ditch Length Start: -500.00cm
Ditch Length End: 5,200.00cm
Original Material: Yes

Equipment List

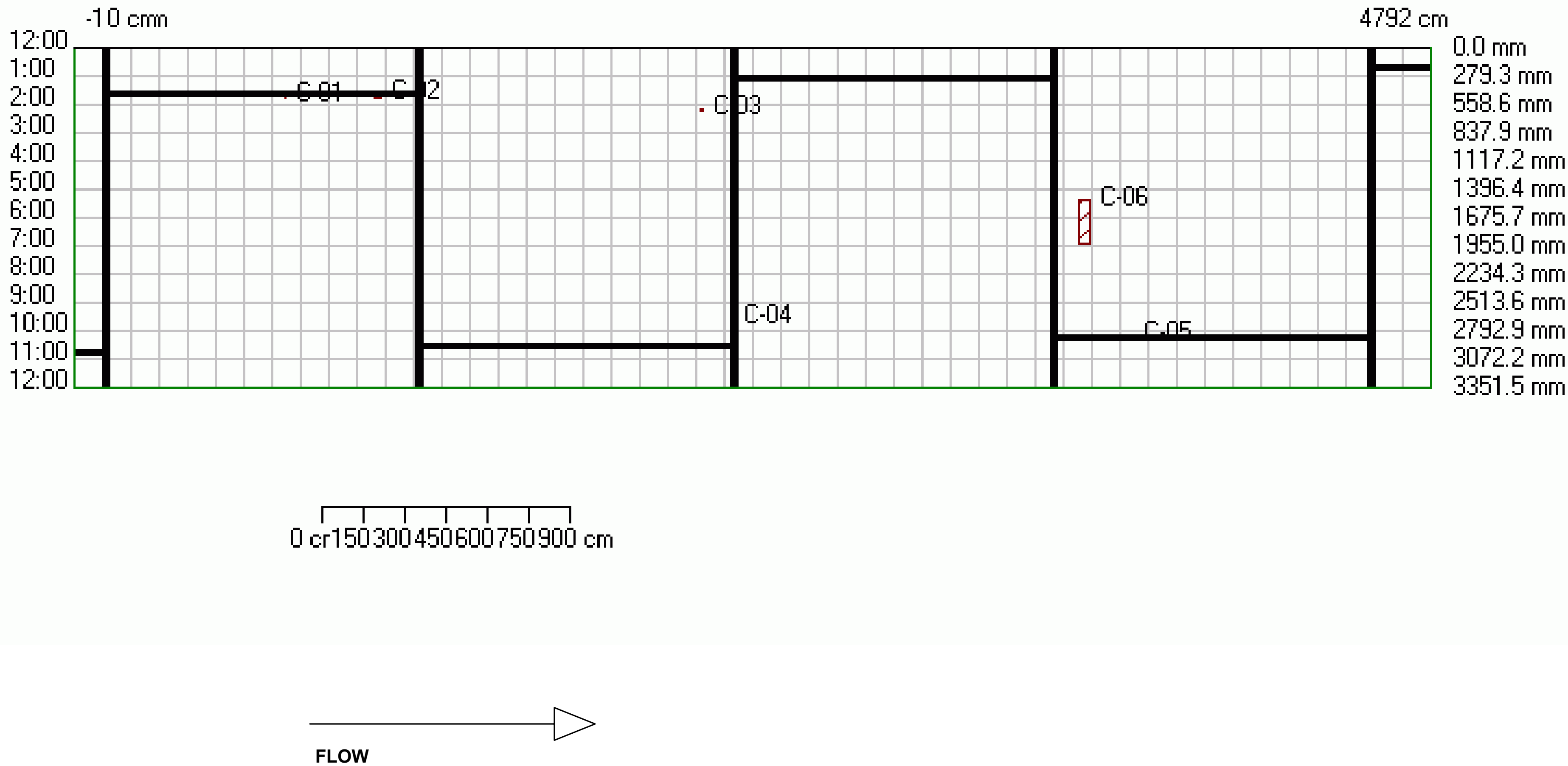
Type	Equipment Make	Model No.	Serial No.	Asset No.	Calibration Due Date
Magnetic Yoke	Contour Probe	Epoch III	972017056158	6158	9/22/2001

11/23/2001 5:41:09PM



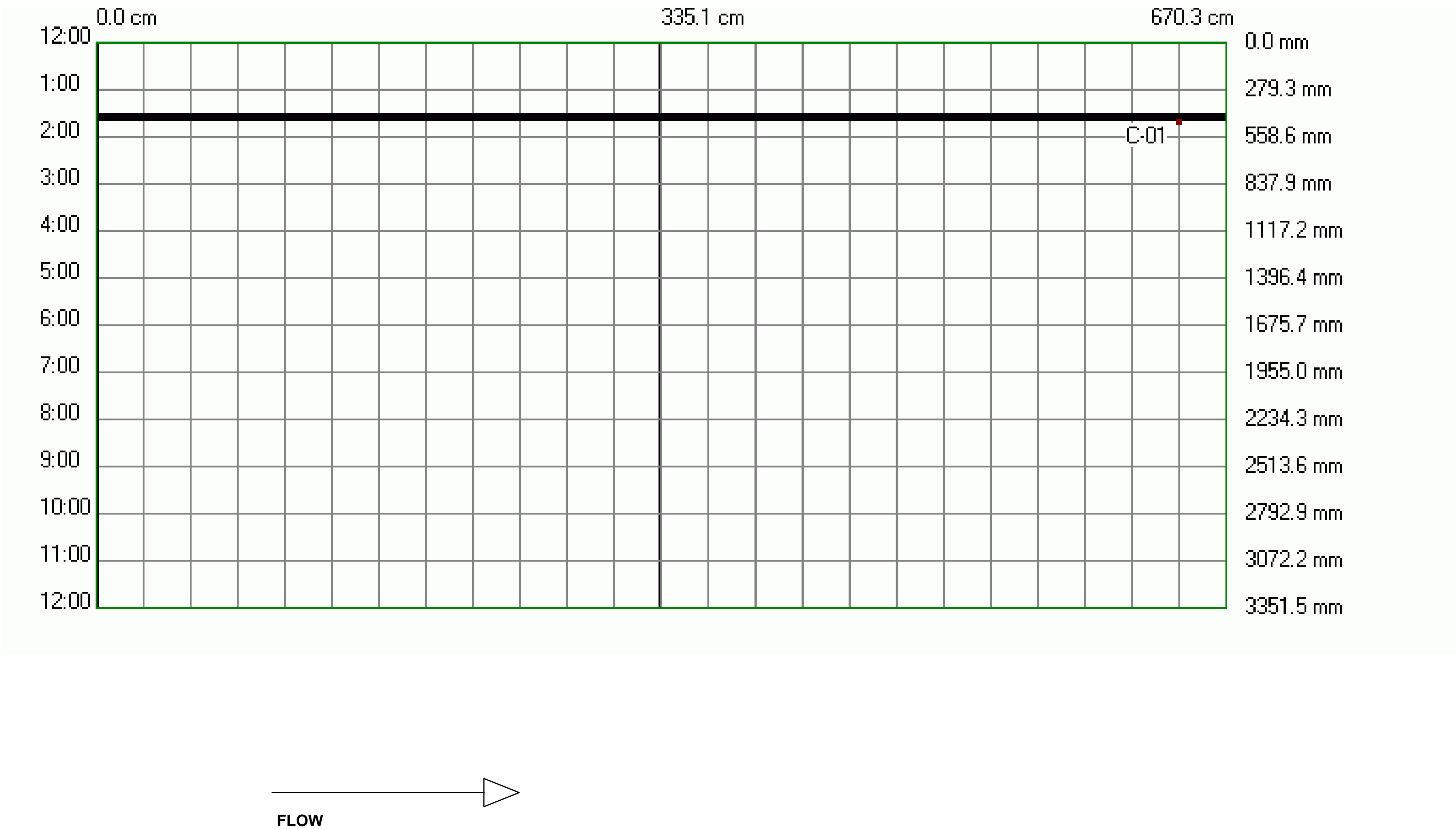
Client:	Line No.:	Chainage of Ref.:	Date:
Union Gas	Trafalgar	62.2 m	2001/08/27
Operating Region:	**DIG No.:**	**Odometer Dist.:**	**Senior Technician:**
Dawn	111 (Dawn)	m	Rob Squair

ID	Description	Axial Distance (cm)	Axial Length (cm)
Soil Information			
ID	**Depth (cm)**	**Thickness (cm)**	**Texture**
Organics	0	30	NA
1	30	302	Clay,Sand

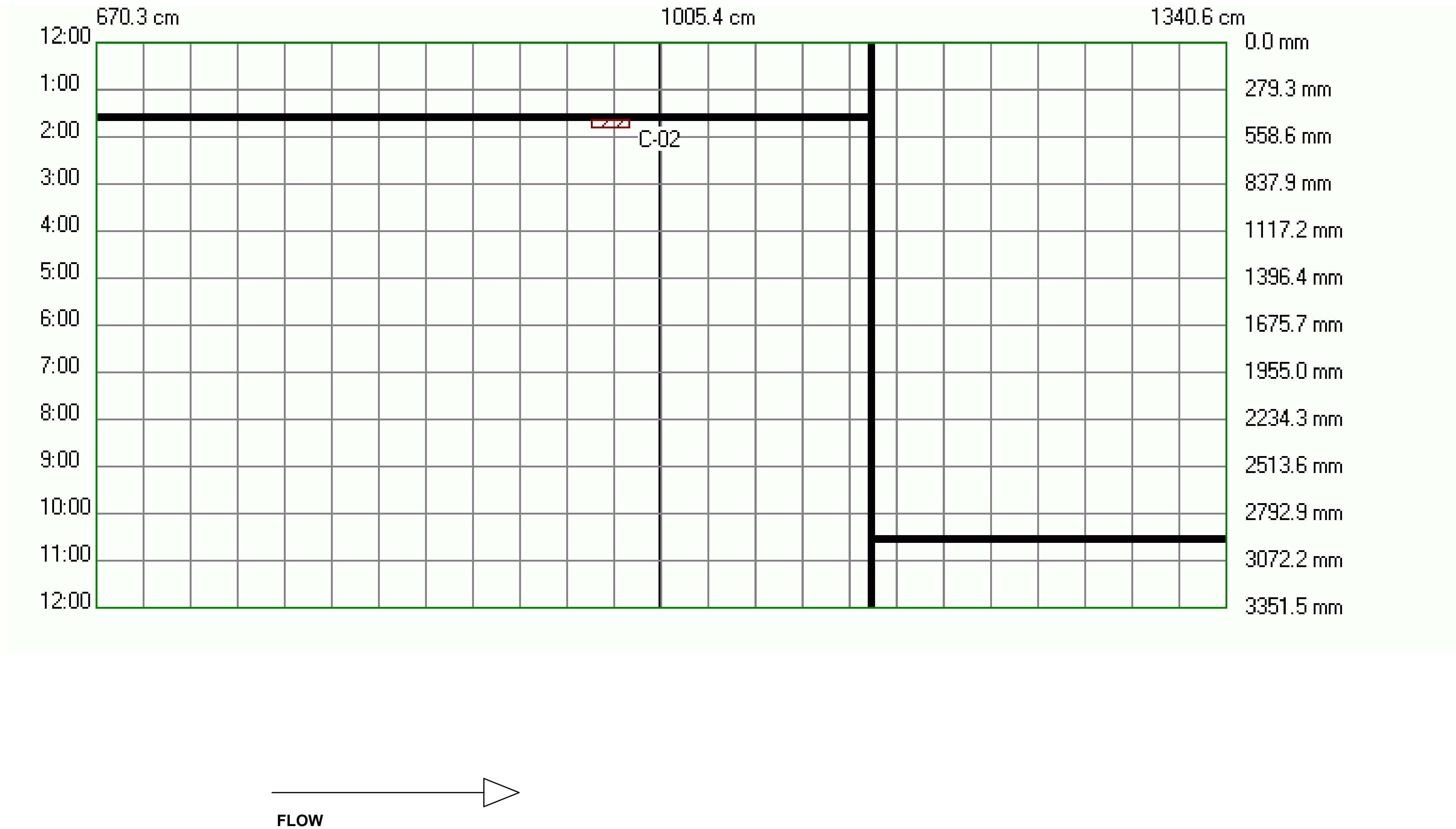


Client: Union Gas	Line No.: Trafalgar	Chainage of Ref.: 62.2 m	Date: 2001/08/27
Operating Region: Dawn	DIG No.: 111 (Dawn)	Odometer Dist.: m	Senior Technician: Rob Squair

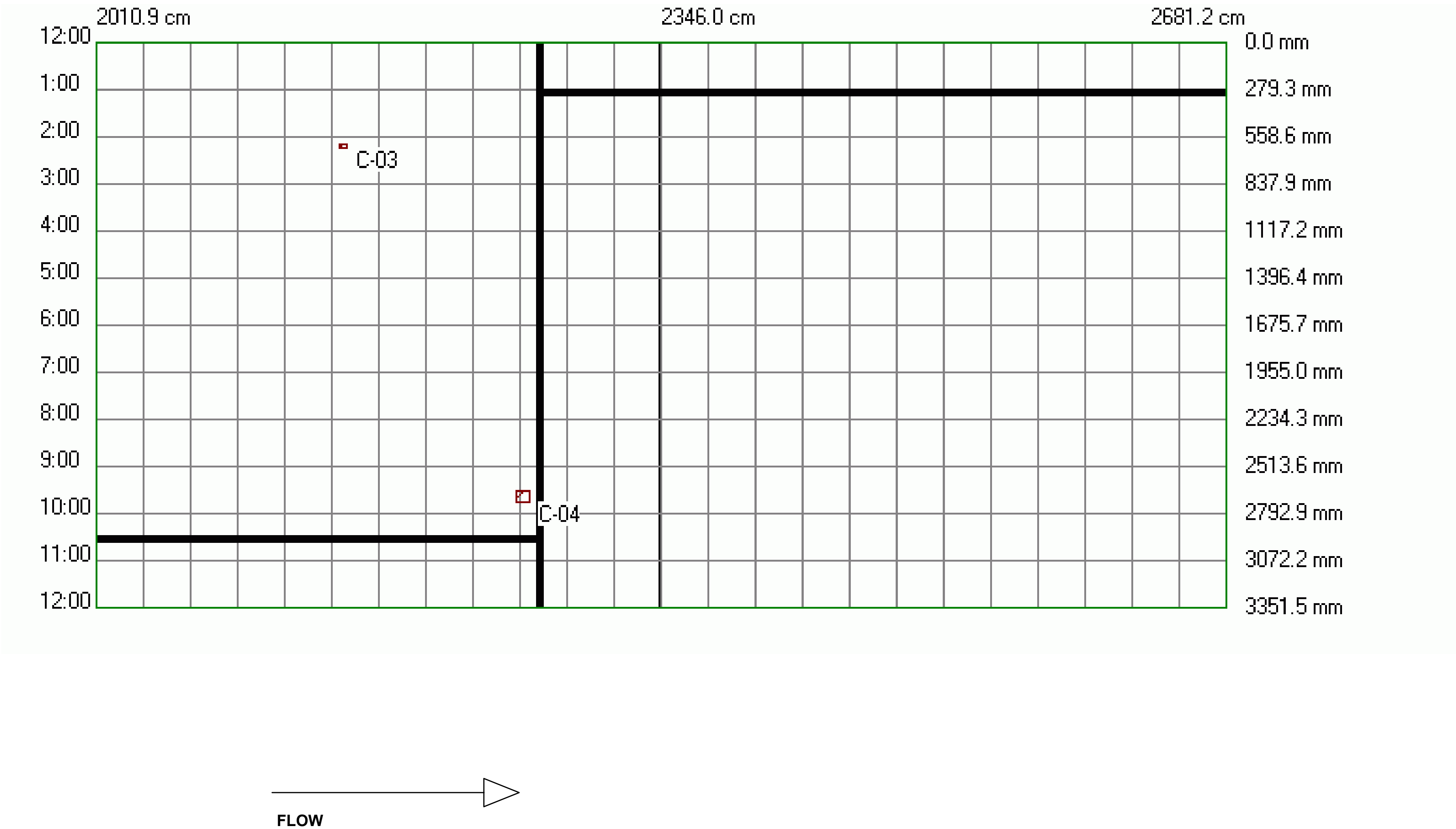
ID	Description	Axial Distance	Axial Length	TDC	Circ.Length	Width	Orientation	Max Depth
Volumetric Anomalies								
C-01	Corrosion	642	2	47	2	2	0	1.3
C-02	Corrosion	975	22	48	4	4	0	0.8
C-03	Corrosion	2157	4	62	2	2	0	1.2
C-04	Corrosion	2265	7.5	-66	6.5	6.5	0	1.4
C-05	Corrosion	3717	5	-52	2	2	0	1.15
C-06	Corrosion	3535	42	-163	30	42	0	1.7



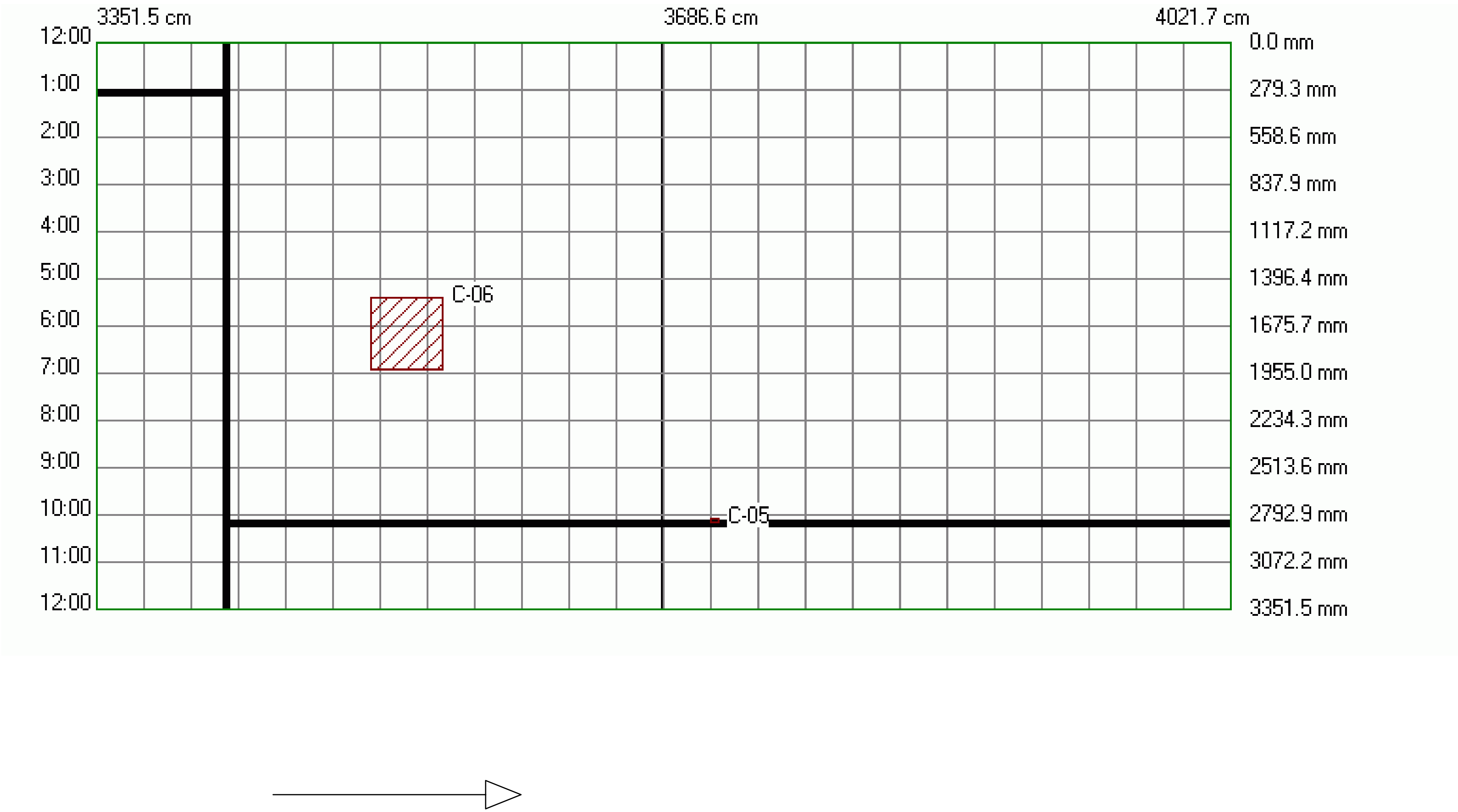
Client: Union Gas	**Line No.:** Trafalgar	**Chainage of Ref.:** 62.2 m	**Date:** 2001/08/27
Operating Region: Dawn	**DIG No.:** 111 (Dawn)	**Odometer Dist.:** m	**Senior Technician:** Rob Squair



Client:	Line No.:	Chainage of Ref.:	Date:
Union Gas	Trafalgar	62.2 m	2001/08/27
Operating Region:	**DIG No.:**	**Odometer Dist.:**	**Senior Technician:**
Dawn	111 (Dawn)	m	Rob Squair



Client:	Line No.:	Chainage of Ref.:	Date:
Union Gas	Trafalgar	62.2 m	2001/08/27
Operating Region:	**DIG No.:**	**Odometer Dist.:**	**Senior Technician:**
Dawn	111 (Dawn)	m	Rob Squair



Client: Union Gas	Line No.: Trafalgar	Chainage of Ref.: 62.2 m	Date: 2001/08/27
Operating Region: Dawn	DIG No.: 111 (Dawn)	Odometer Dist.: m	Senior Technician: Rob Squair

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

Looking up-stream

Dig site area

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)


Looking down-stream


Composition

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

Photo of Dis-01

Photo of Dis-02

Excavation Photos

Photo of Dis-03

Photo of Dis-04

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

Photo of Dis-05

Photo of Dis-06

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

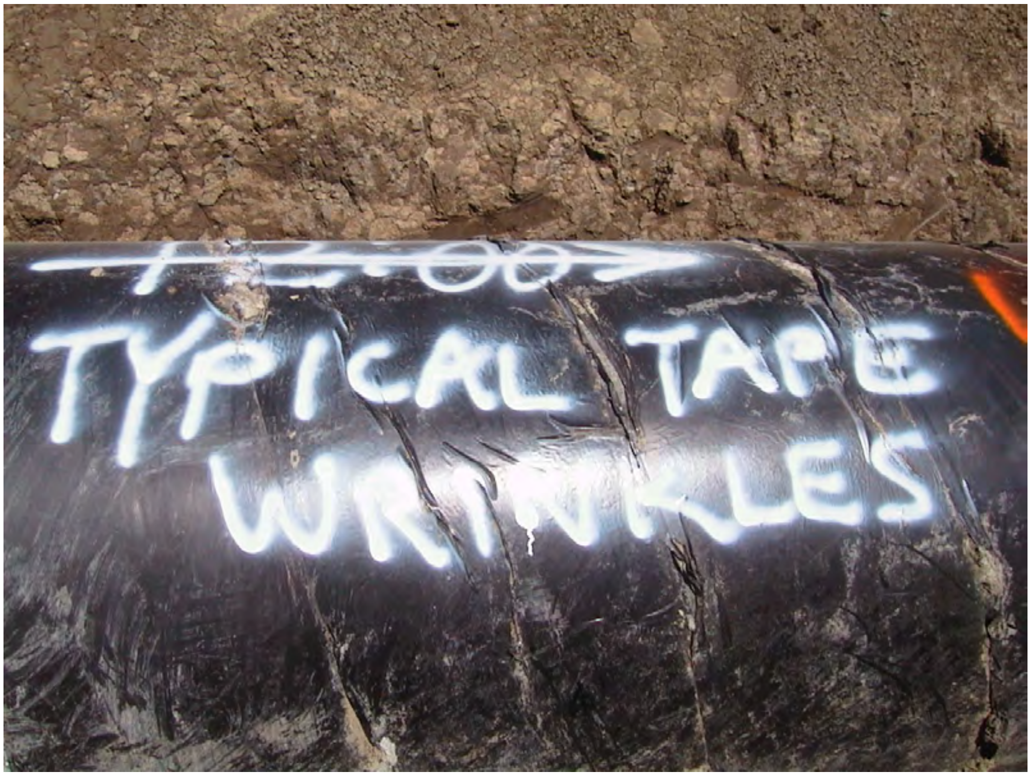


Photo showing typical tape wrinkles along entire dig site

Photo of deposits at Dis-06

Excavation Photos

Photo of Hol-01

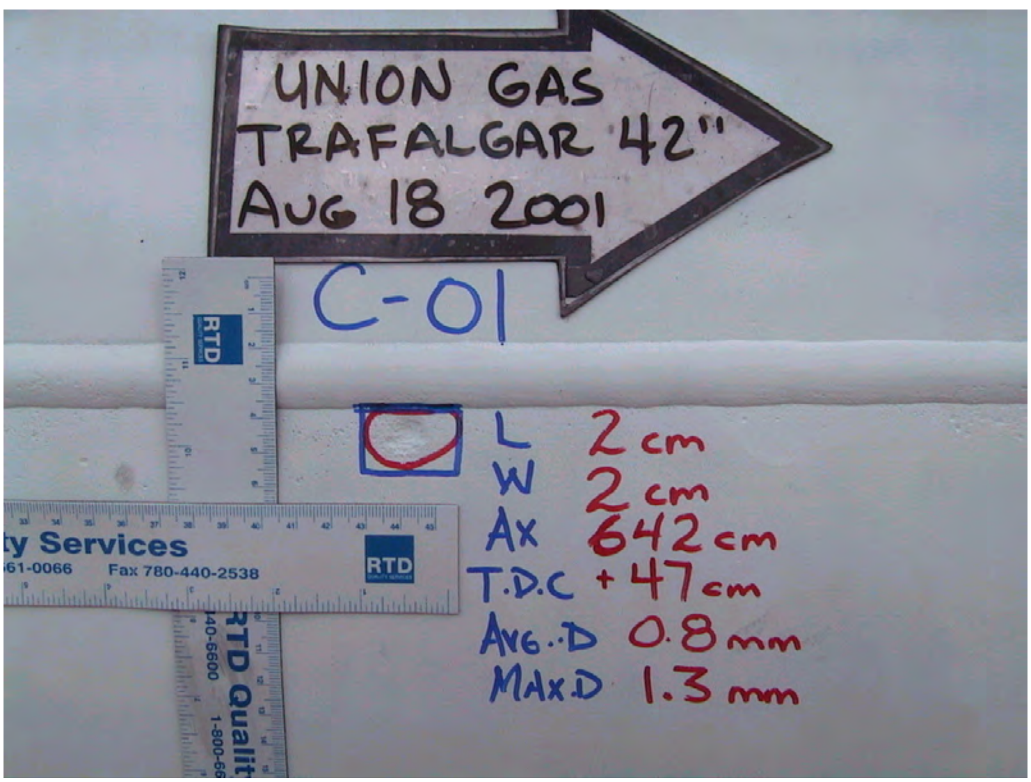


Photo of C-01

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

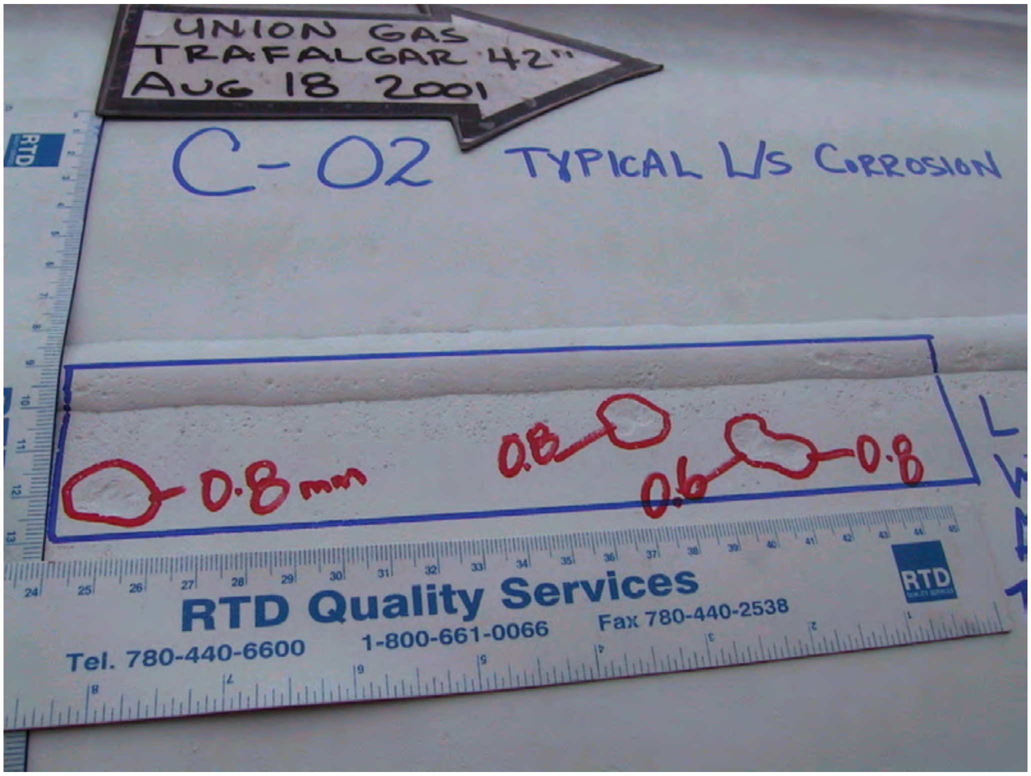


Photo of C-02 (typical L/S corrosion)

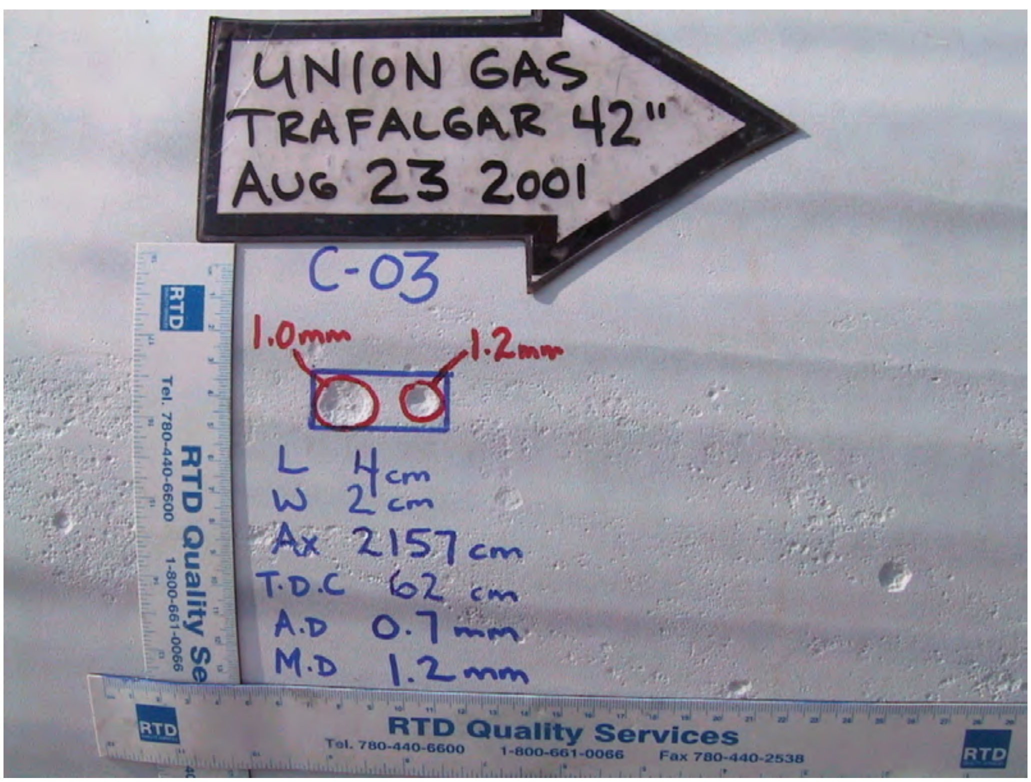


Photo of C-03

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

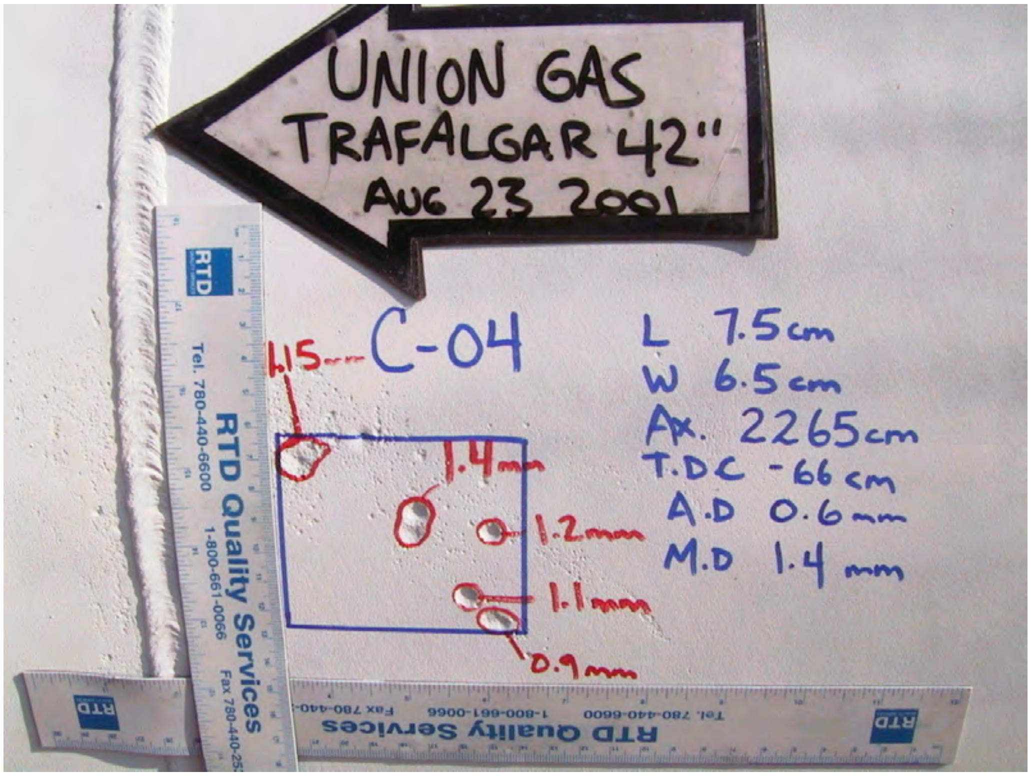


Photo of C-04

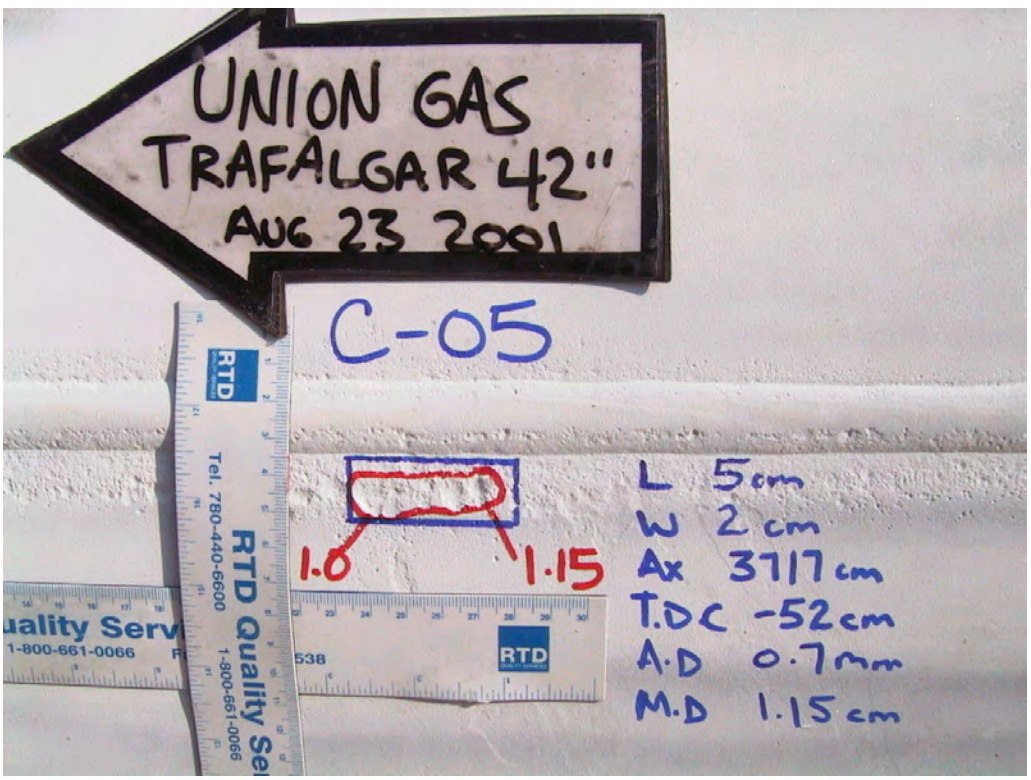


Photo of C-05

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

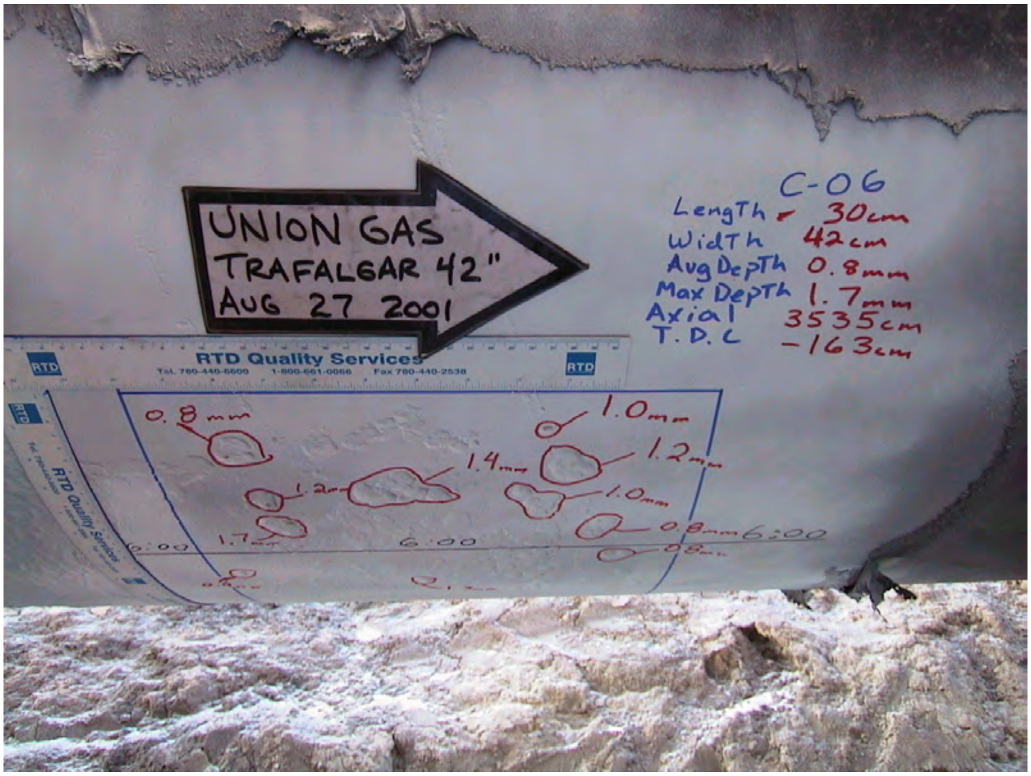
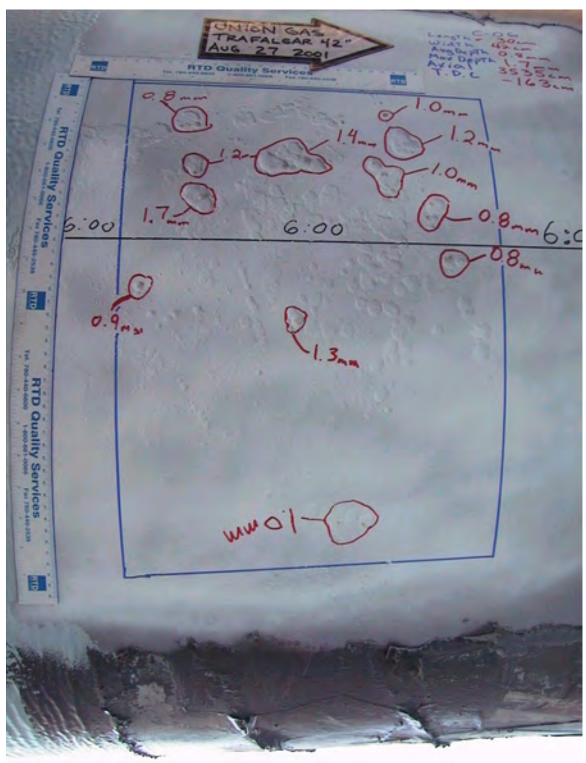


Photo of C-06



Close-up of C-06

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

Photo of GW #1 (Reference GW)

Photo of GW #2

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

Photo of GW #3

Photo at GW #4

Excavation Photos

Summer 2001 Dig Program
Site No.: 111 (Dawn)

Photo of GW #5

Ditch overview

ACUREN

Acuren Group Inc.
2190 Speers Road
Oakville, ON L6L 2X8

Phone: 905-825-8595
Fax: 905-825-8598

Materials Engineering and Testing
a Rockwood Company

Pipeline Integrity Inspection Report

NPS 42 Trafalgar Digs
Site 1

Report Prepared For:

uniongas

50 Keil Drive North
PO Box 2001
Chatham, Ontario, Canada
N7M 5M1

Inspection By:

ACUREN

ACUREN JOB No: GL 130-5-0013
PURCHASE ORDER No: 4500124214
DECEMBER 2005

NPS 42 Trafalgar Site 1 Table of Contents

NPS 42 Trafalgar Site 1 Photographs

CANSPEC

Summary: Trafalgar NPS 42 Dig #1

Dig ID: **AGM: Chainage**

Date: **October 24, 2005**

SCOPE OF WORK: Canspec scope of work for these excavations follows UGL specification emailed July 15, 2005 from Tom Hamilton and subsequent conversations there after. which involve: All information relevant to site location and GPS coordinates are provided by UGL inspectors. No soil sampling required, this is to be evaluated on a individual basis depending on our findings. All sandblasted areas are to be VT and MT examined in search of both the target defects and any other external feature as characterized by UGL procedure and Code Z662. All information to be relayed to UGL Eng for evaluation.

Dig site 1 is located in a cleared, level wooded area East of the Union Gas Bentpath station. A coating and corrosion assessment was not required for this inspection thus soil samples were not collected and cathodic potential was not measured. The pipe wall thickness was measured to be 11.2mm thick

No dents or SCC were found on the pipe.

Twenty six areas of corrosion were noted having wall a loss of less than 10% the actual wall thickness. Most of the corrosion was found next to the long seam. Three arc burns were found and four areas of mechanical damage were recorded. Cracks running longitudinally along the pipe were recorded in seven areas with depths of between 4-6% of the actual wall thickness.

Remediation action required the removal of all seven linear indications, four mechanical damage areas of three arc burns. Linear indications were removed using the approved grinding procedure. A rubber backed 120 grit buffing disc was used to remove all indications to a maximum of 10% of the actual wall thickness ensuring a smooth transition back to the pipe surface while minimizing the grind length and not exceeding 240mm. All linear indications were removed, with the longest grind length being 230mm and remaining wall thickness measuring no less than 10.7mm thick. All four mechanical damages were removed using the approved grinding procedure and were magnetic particle tested to ensure removal. All defects were ground smooth to the pipe surface. Arc burns were removed to less than 10% of the actual wall thickness and 5% nital etch and magnetic particle testing was performed to ensure complete removal of the arc burns.

An additional 1m of NDE corrosion assessment was requested at the downstream end of the pipe. Seven areas of disbondment were found with corrosion products but no electrolytes. Sand from the sandblasting equipment was found beneath the disbondments. Four areas of corrosion were noted, with the deepest having a wall loss of 1.4mm. Seven linear indications were found, with LIN-08 along the long seam in COR-29 (photograph 95). Two areas of mechanical damage were noted. MD-06 is a previous grind and MD-05 is a gouge.

On November 9, 2005, an x-ray was taken of LIN-08 and the image did not reveal the indication depth. Remediation action for this area was provided over the phone by Rob Marson on November 10, 2005 and completed that same day. All linear indications and mechanical defects were removed below 10% of the nominal wall thickness.

An additional meter of NDE (NDE2) was performed East of the second exposed girth weld. Corrosion features COR-(27-30), linear indications LIN-(08-16) and MD-06 were identified in this region. On November 10, 2005, all linear indications and MD-06 was smoothed out using approved grinding procedures supplied by Union Gas Ltd. Engineering.

CANSPEC

Pipeline Integrity Field Inspection Report
Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Basic Information

Dist from Launch (m): NA
Kilometre Post: NA
Reference Girth Weld: Exposed

Pipe Information

Line #: Trafalgar NPS 42 Dig #1
Line Diameter (mm): 1165.0
Long Seam Type: DSAW
Nominal Pipewall Thickness (mm): 11.20
Actual Pipewall Thickness (mm): 11.20

ILI Dig Information

Type of ILI Tool: NA
ILI Inspection Date: NA
Tool Vendor: NA
Reason for Excavation: Corrosion **SCC**

Location Information

1/4 sec (lot): NA
SEC (conc): NA
TWP: NA
RGE: NA
W: NA
Other (GPS): -82.2124511 Longitude 42.7177154 Latitude
AGM: Chainage
Distance from AGM to GW (m): 399
GW is U/S or D/S to AGM: NA

Excavation Information

Start of NDE to Reference Point (m): -1.00
End of NDE to Reference Point (m): 6.60
Depth of Cover (m): 1.40
Excavation Length (m): 16.40
Excavation Width (m): 7.80

GW Number Exposed*	Joint Length (m)	Type of Joint Exposure	Longseam Orientation (Clock Position)	Method of detecting the LS weld
East of Exposed		Partial	1:46	Visual
West of Exposed		Partial	9:39	Visual

*Only to be filled in for welds that are fully exposed.

Technician 1 James Allen
Technician 2 Dan Kviring

On File
Signature

On File
Signature

Pipe Pressure at Time of Inspection (PSI)
Pipe Temperature (C):

Method of MPI Color Contrast - Water Based

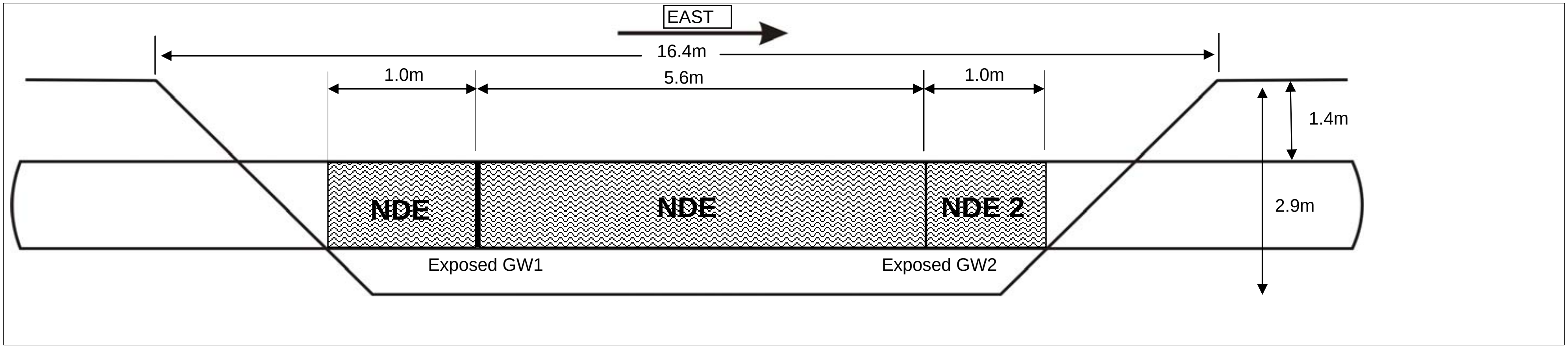
Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Sketch of Excavation

ELEVATION VIEW



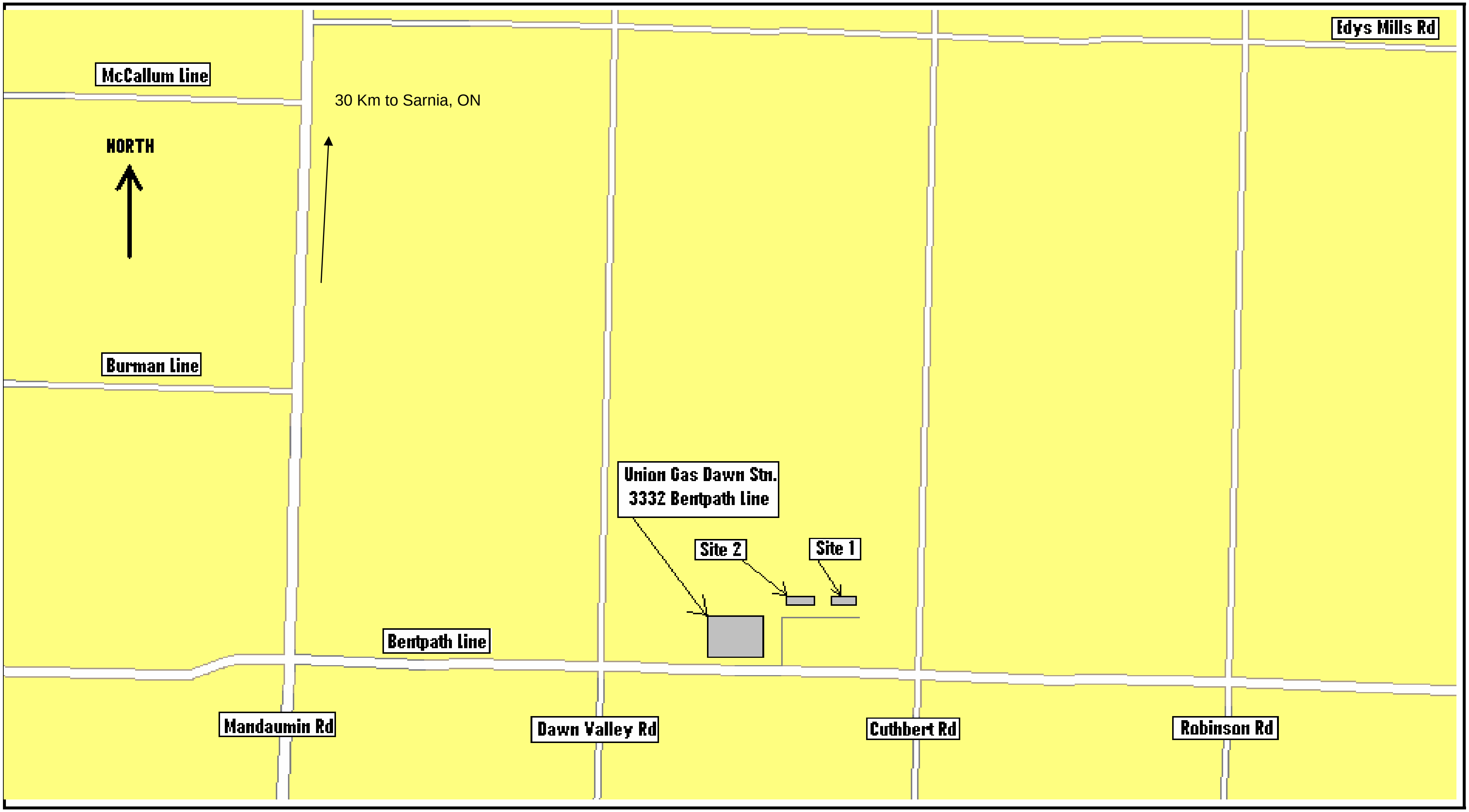
All measurements must be made from reference.

Does section have sag?	☐ Yes ☑ No **If Yes,**	Location from reference (m):	------	Reference Point:	GW1
Does section have an overbend?	☐ Yes ☑ No **If Yes,**	Location from reference: (m)	------	Excavation Width (m)	7.80
Number of full joints in excavation:		Excavation Type (**F**ull/**B**ell)		Depth of Ditch (m)	2.90
Start of exposed pipe (360°) to reference (m)	-1.00	End of exposed pipe (360°) to reference (m)	6.600	Depth of Cover (m)	1.40
Start of NDE to reference point (m)	-1.00	End of NDE to reference point (m)	6.600	Ditch Length (m)	16.40
Spiral Weld? ☐ Yes ☑ No **If no,**		Longseam Orientation East of GW 1	1 : 46 o'clock	Dist Long seam from TDC (mm)	537
		(Clock Position): West of GW 1	9 : 39 o'clock	Dist Long seam from TDC (mm)	2945

Site Diagram Trafalgar NPS 42 Dig #1

Dig ID: Trafalgar NPS 42 Dig #1

Date: October 24, 2005



CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Soil and Landscape Information

Land Use	Cultivated
Site Position	Level
Topography	Level
Parent Material	Till (Moraine)
Texture	Sandy Clay Loam
Coarse Fragments	Estimated % By Volume: **10%**
	☐ Boulders (> 60 cm) ☑ Small Stones (2.5 cm <= X<10)
	☐ Large Stones (10 cm <= X<60) ☑ Gravel (<2.5 cm)
Drainage	Poor
Gleying	Strongly Gleyed (Dark Grey)
Mottling	Abundance: Common
	Size: Medium
	Contrast: Distinct
Visible Salts	☐ Surface Salt Crusts (White and Powdery)
(Check All That Apply)	☐ White/Grey Salts at Pipe Depth That Don't React With Acid
	☐ Gypsum (Clear to Brown) Salt Crystals At Pipe Depth-Don't React With Acid
	☐ Other (Explain in Comments)

Soil and Environmental Comments

Gleying and mottling present in the soil pile.

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Sampling and Analysis

SOIL

Sample No.	Location	pH	ORP	10% HCl Reaction

ELECTROLYTE

Sample No.	Sample Taken (Y/N)	Location	pH
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

GROUNDWATER

Sample No.	Location	pH	ORP

Sampling and Analysis Comments

No groundwater was present in the excavation. Soil samples were not required as part of this inspection. Coating was removed and the pipe surface was sandblasted prior to inspection.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Coating Condition

Pipe Coating Type Polyethylene Tape
Weld Coating Type Polyethylene Tape
Cathodic Potential (mV) US/DS

Pipe Coating Condition Poor
Weld Coating Condition Poor

Coating Comments
Coating was removed prior to investigation.

Corrosion Deposits

Corrosion Present ☑ Yes ☐ No

Colour		Texture		Magnetic Reaction		Carbonate Reaction (10% HCl Reaction)	
White	☐	Film	☐	Strong Magnetic Reaction	☐	Bubbles Strongly	☐
Brown	☑	Pasty	☐	Weak Magnetic Reaction	☐	Bubbles Weakly	☑
Black	☐	Scaly	☑	Does Not React	☑	Does not Bubble	☑
Green	☐	Powdery	☑			Rotten Egg Smell	☑
Olive/ Beige	☑	Metallic	☐			Turns Yellowish	☐
Orange	☑	Waxy	☐			Turns Clear	☐
Blue	☐						
Grey	☐						
Red	☑						
Clear	☐						

Samples Collected

Sample Number	Associated Feature / Location
1	H-03
2	Longseam

Corrosion Product Comments
Corrosion examination was not required as part of this inspection. Sample 2: Weak bubbling in orange corrosion product. No bubbling in beige corrosion product. Beige corrosion product gives off a rotton egg smell. Sample 1: Strong bubbling, no rotton egg odour and is not magnetic.

CANSPEC

Pipeline Integrity Field Inspection Report
Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

COATING INSPECTION

AREAS OF DISBONDMENT (Includes Wrinkling) AND MAJOR HOLIDAYS

Feature Number	Start of Feature Axially (mm)	End of Feature Axially (mm)	Axial Length (mm)	Top Dead Centre to Start of Feature (Circ.) (mm)	Top Dead Centre to End of Feature (Circ.) (mm)	Circumferential Width (mm)	Clock Position (to start of feature)	Reason for Disbond (1)	pH @pipe surface
H-01	5740	5810	70.0	20	210	190.0	: 04		
H-02	5920	6030.0	110.0	620.0	750.0	130.0	2 : 02		
H-03	6050.0	6520.0	470.0	180.0	600.0	420.0	: 35		
H-04	6030.0	6080.0	50.0	980.0	1070.0	90.0	3 : 13		
H-05	5960.0	6210.0	250.0	2550.0	3300.0	750.0	8 : 22		
H-06	6440.0	6520.0	80.0	2600.0	3300.0	700.0	8 : 31		
H-07	6470.0	6600.0	130.0	2500.0	2660.0	160.0	8 : 12		

Comments

Coating assessment was not required as part of this inspection.

Seven areas of disbondment were noted upstream of the initial area of NDE. No electrolytes were found beneath the coating. Blasting sand was found beneath coating.

Pipeline Integrity Field Inspection Report
Trafalgar NPS 42 Dig #1
AGM: Chainage

Corrosion Map of Feature H1 & H2

Client: Union Gas
Date: 24-Oct-05

Each Square =	0.1885714	m
Coating Thickness =	#DIV/0!	mils

Coating thickness gaug	X	
Pit Depth Gauge		

Direction of Flow

Map X axis represents longitudinal distance in mm from referenc
Map Y axis represents distance measured from TDC in mm

Symbols are B for bare, D for disbonded. Numbers are coating thickness in mils.
Black numbers are pipe coating thickness surface pH numbers in blue

	0.0	0.2	0.4	0.6	0.8	0.9	1.1	1.3	1.5	1.7	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	CLOCK POSITION
10																																				12:00
40																																				
70																																				
100																																				
130																																				
160																																				
190																																				
220																																				
250																																				
280																																				3:00
310																																				
340																																				
370																																				
400																																				
430																																				
460																																				
490																																				
520																																				6:00
550																																				
580																																				
610																																				
640																																				
670																																				
700																																				
730																																				
760																																				9:00
790																																				
820																																				
850																																				
880																																				
910																																				
940																																				
970																																				
1000																																				
1030																																				12:00

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1

AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Corrosion Assessment

RSTRENG Completed by NA **Assessment Method** Visual, UT

Corrosion Feature Number	Type of Corrosion	Relative to Girth Weld Start of Cluster (mm)	Relative to Girth Weld End of Cluster (mm)	Total Length of Cluster (mm)	Effective RSTRENG Start Length (mm)	Effective RSTRENG Cluster Length (mm)	Circ Start of Cluster (mm)	Circ End of Cluster (mm)	Circ Width of Cluster (mm)	O'Clock From	O'Clock To	Lowest Actual Remaining Wall Thickness (mm)	Max Depth (mm)	Max Depth (%)	RSTRENG Results (RPR) (Case 1: Effective Area)	RSTRENG Results (RPR) (Case 2 0.85 DL)	On or Near Weld (Y/N) *	Rubbing Submitted (Y/N)	Reason for Repair	Sleeved (Y/N)	Figure Number
COR-01	External	25	75	50			555	595	40	1:49	1:57	10.20	1.00	9%			Y	N	Repair not Required		10
COR-02	External	155	170	15			555	570	15	1:49	1:52	9.90	1.30	12%			Y	N	Repair not Required		11
COR-03	External	270	330	60			545	570	25	1:47	1:52	10.20	1.00	9%			Y	N	Repair not Required		12
COR-04	External	20	150	130			765	905	140	2:30	2:58	10.20	1.00	9%			N	N	Repair not Required		13
COR-05	External	20	35	15			1010	1030	20	3:19	3:23	9.90	1.30	12%			N	N	Repair not Required		14
COR-06	External	20	45	25			1110	1195	85	3:38	3:55	10.20	1.00	9%			N	N	Repair not Required		15
COR-07	External	535	545	10			550	560	10	1:48	1:50	10.20	1.00	9%			Y	N	Repair not Required		16
COR-08	External	565	575	10			545	560	15	1:47	1:50	10.20	1.00	9%			Y	N	Repair not Required		16
COR-09	External	620	930	310			545	610	65	1:47	2:00	9.90	1.30	12%			Y	N	Repair not Required		17
COR-10	External	1070	1080	10			555	565	10	1:49	1:51	10.20	1.00	9%			Y	N	Repair not Required		18
COR-11	External	1135	1510	375			545	640	95	1:47	2:06	9.70	1.50	13%			Y	N	Repair not Required		19
COR-12	External	1545	1580	35			555	580	25	1:49	1:54	10.20	1.00	9%			Y	N	Repair not Required		20
COR-13	External	1610	1640	30			560	605	45	1:50	1:59	10.20	1.00	9%			Y	N	Repair not Required		20
COR-14	External	1750	1975	225			545	610	65	1:47	2:00	9.90	1.30	12%			Y	N	Repair not Required		21
COR-15	External	2140	2260	120			545	565	20	1:47	1:51	10.20	1.00	9%			Y	N	Repair not Required		22
COR-16	External	2095	2360	265			630	745	115	2:04	2:27	10.20	1.00	9%			N	N	Repair not Required		23
COR-17	External	2375	2490	115			545	595	50	1:47	1:57	10.20	1.00	9%			Y	N	Repair not Required		24
COR-18	External	2550	2600	50			555	600	45	1:49	1:58	9.80	1.40	13%			Y	N	Repair not Required		25
COR-19	External	2850	3100	250			545	585	40	1:47	1:55	10.20	1.00	9%			Y	N	Repair not Required		26
COR-20	External	3330	3345	15			555	570	15	1:49	1:52	10.20	1.00	9%			Y	N	Repair not Required		27
COR-21	External	3670	3750	80			545	575	30	1:47	1:53	10.20	1.00	9%			Y	N	Repair not Required		28
COR-22	External	3800	3850	50			545	565	20	1:47	1:51	10.20	1.00	9%			Y	N	Repair not Required		29
COR-23	External	4765	4900	135			545	580	35	1:47	1:54	10.20	1.00	9%			Y	N	Repair not Required		30
COR-24	External	5000	5080	80			545	565	20	1:47	1:51	10.20	1.00	9%			Y	N	Repair not Required		31
COR-25	External	5215	5270	55			555	575	20	1:49	1:53	10.20	1.00	9%			Y	N	Repair not Required		32
COR-26	External	-80	-250	170			2900	2945	45	9:30	9:39	10.20	1.00	9%			N	N	Repair not Required		33

* **ON** - On Weld, **NEAR** - From toe of weld to 10 mm

Corrosion Comments

All corrosion measured wall loss of less than 10% the nominal wall thickness unless otherwise noted. COR-26 is located upstream from the exposed girth weld.

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Corrosion Assessment

RSTRENG Completed by ______________________ **Assessment Method** Visual, UT

Corrosion Feature Number	Type of Corrosion	Relative to Girth Weld Start of Cluster (mm)	Relative to Girth Weld End of Cluster (mm)	Total Length of Cluster (mm)	Effective RSTRENG Start Length (mm)	Effective RSTRENG Cluster Length (mm)	Circ Start of Cluster (mm)	Circ End of Cluster (mm)	Circ Width of Cluster (mm)	O'Clock From	O'Clock To	Lowest Actual Remaining Wall Thickness (mm)	Max Depth (mm)	Max Depth (%)	RSTRENG Results (RPR) (Case 1: Effective Area)	RSTRENG Results (RPR) (Case 2 0.85 DL)	On or Near Weld (Y/N) *	Rubbing Submitted (Y/N)	Reason for Repair	Sleeved (Y/N)	Figure Number
COR-27	External	5560	5780	220			570	600	30	1 : 52	1 : 58	9.80	1.40	13%			Y	N	Repair not Required		88
COR-28	External	6040	6120	80			570	600	30	1 : 52	1 : 58	10.20	1.00	9%			Y	N	Repair not Required		90
COR-29	External	6260	6430	170			570	615	45	1 : 52	2 : 01	10.10	1.10	10%			Y	N	Repair not Required		92
COR-30	External	5690	5720	30			992	1022	30	3 : 15	3 : 21	10.20	1.00	9%			N	N	Repair not Required		94

* **ON** - On Weld, **NEAR** - From toe of weld to 10 mm

Corrosion Comments COR-(27,28,29,30) are located downstream of the initial area of NDE.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Grind Assessment

Grind Feature Number	Corresponding Features Within Grind Area	Measured Wall Thickness Before Grinding (mm)	Measured Wall Thickness After Grinding (mm)	Measured Grind Length after Grinding (mm)	Type of Repair	Client Contacted (Y/N)
GR-01	LIN-01	10.90	10.80	60	Removed	N
GR-02	LIN-02	10.90	10.70	90	Removed	N
GR-03	LIN-(03,04)	10.90	10.70	230	Removed	N
GR-04	LIN-05	10.90	10.70	15	Removed	N
GR-05	LIN-06	10.90	10.80	105	Removed	N
GR-06	ARC-01	11.10	10.80	25	Removed	N
GR-07	MD-01	11.00	10.80	30	Removed	N
GR-08	MD-02	11.00	10.90	25	Removed	N
GR-09	MD-03	11.00	10.90	15	Removed	N
GR-10	MD-04	11.00	10.90	15	Removed	N
GR-11	ARC-02	11.10	10.80	15	Removed	N
GR-12	ARC-03	11.10	10.90	10	Removed	N
GR-13	LIN-07	11.00	10.60	40	Removed	N
GR-14	LIN-09	11.40	11.10	30	Removed	N
GR-15	LIN-10	11.40	11.10	105	Removed	N
GR-16	LIN-(12-15)	11.30	10.90	130	Removed	N
GR-17	LIN-16	11.30	11.10	30	Removed	N
GR-18	LIN-11	11.40	11.10	65	Removed	N
GR-19	MD-05	11.40	11.20	30	Removed	N
GR-20	LIN-08	11.50	11.00	215	Removed	N
GR-21	MD-06	11.40	11.00	160	Removed	Y

Grind Area Comments

GR-(14-21) are found in the area of NDE II completed on Nov. 10, 2005.

	Wall Thickness @ East of Exposed GW			
	Upstream (mm)		Downstream (mm)	
12:00	11.20		11.10	
3:00	11.20		11.10	
6:00	11.20		11.20	
9:00	11.20		11.20	

	Wall Thickness @ West of Exposed GW			
	Upstream (mm)		Downstream (mm)	
12:00	11.20			
3:00	11.10			
6:00	11.20			
9:00	11.30			

Mechanical Damage and Arc Burn Assessment

Damage Feature Number	Relative Distance to U/S GW to feature (mm)	Orientation of Feature (Clock Position)	Type of Damage	Length (mm)	Max Depth (mm)	Max Depth (%)	Figure Number
MD-01	2735	3:40 - 3:56	Scrape /Gouge	35	0.20	2%	50
MD-02	3460	2:56	Scrape /Gouge	20	0.20	2%	53
MD-03	3915	3:42 - 3:44	Scrape /Gouge	10	0.20	2%	56
MD-04	3915	3:51 - 3:53	Scrape /Gouge	10	0.20	2%	56
ARC-01	5	3:36 - 3:39	Arc Burn	20	0.30	3%	47
ARC-02	-8	7:30	Arc Burn	4	0.30	3%	59
ARC-03	8	6:38	Arc Burn	6	0.20	2%	62
MD-05	5635	3:44	Scrape /Gouge	25	0.20	2%	105
MD-06	6330	2:45-4:47	Scrape /Gouge	180	0.10	1%	107

Mechanical Damage and Arc Burn Comments

ARC-02 is located upstream from the exposed girth weld.

	Wall Thickness @			
	Upstream (mm)		Downstream (mm)	
12:00				
3:00				
6:00				
9:00				

	Wall Thickness @			
	Upstream (mm)		Downstream (mm)	
12:00				
3:00				
6:00				
9:00				

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Linear Indication Assessment

NDT Inspector James Allen **NDT Company** Acuren Group Inc

Linear Indication Feature Number	ILI Area Number (From Field Sheets)	Type of Indication	Indication Relative Position*	Indication Radial Position	Axial Start of Indication (mm)	Axial End of Indication (mm)	Axial Length of Indication (mm)	Circ Orientation of Linear Indication (mm)	Clock Position	Indication in Corrosion (Y/N)	Indication Depth (mm)	Indication Depth (%)	Type of Repair	NDT Analysis Method Used to Size Feature	Figure Number
LIN-01	-	Crack	BM	EXT - External	960	1110	150	950	3 : 07	N	0.50	4%	Removed	UT	34
LIN-02	-	Crack	BM	EXT - External	342	440	98	820	2 : 41	N	0.50	4%	Removed	UT	37
LIN-03	-	Crack	BM	EXT - External	420	570	150	840	2 : 45	N	0.70	6%	Removed	UT	39
LIN-04	-	Crack	BM	EXT - External	575	705	130	840	2 : 45	N	0.40	4%	Removed	UT	40
LIN-05	-	Crack	BM	EXT - External	635	650	15	865	2 : 50	N	0.50	4%	Removed	UT	40
LIN-06	-	Crack	BM	EXT - External	710	830	120	870	2 : 51	N	0.50	4%	Removed	UT	43
LIN-07	-	Crack	BM	EXT - External	1375	1410	35	3125	10 : 15	N	0.70	6%	Removed	UT	65
LIN-08	-	Other (description)	AW	EXT - External	6270	6430	160	550	1 : 48	Y	0.30	3%	Removed	UT	95
LIN-09	-	Other (description)	BM	EXT - External	5910	5950	40	765	2 : 30	N	0.30	3%	Removed	UT	97
LIN-10	-	Other (description)	BM	EXT - External	6240	6350	110	850	2 : 47	N	0.40	4%	Removed	UT	99
LIN-11	-	Other (description)	BM	EXT - External	5930	5990	60	1000	3 : 17	N	0.30	3%	Removed	UT	101
LIN-12	-	Other (description)	BM	EXT - External	5780	5800	20	820	2 : 41	N	0.30	3%	Removed	UT	103
LIN-13	-	Other (description)	BM	EXT - External	5800	5805	5	800	2 : 37	N	0.30	3%	Removed	UT	103
LIN-14	-	Other (description)	BM	EXT - External	5775	5795	20	800	2 : 37	N	0.30	3%	Removed	UT	103
LIN-15	-	Other (description)	BM	EXT - External	5730	5750	20	800	2 : 37	N	0.30	3%	Removed	UT	103
LIN-16	-	Other (description)	BM	EXT - External	5690	5705	15	800	2 : 37	N	0.30	3%	Removed	UT	103

* **IW** - In Weld, **AW** - At Weld (From toe of weld to 10 mm), **BM** - Base Metal (From 11 mm past toe of weld)

Linear Indication Comments

Linear Indications 8-16 are found in the area beyond initial NDE. Depth for LIN-08 uncertain because it lies in an area of corrosion.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

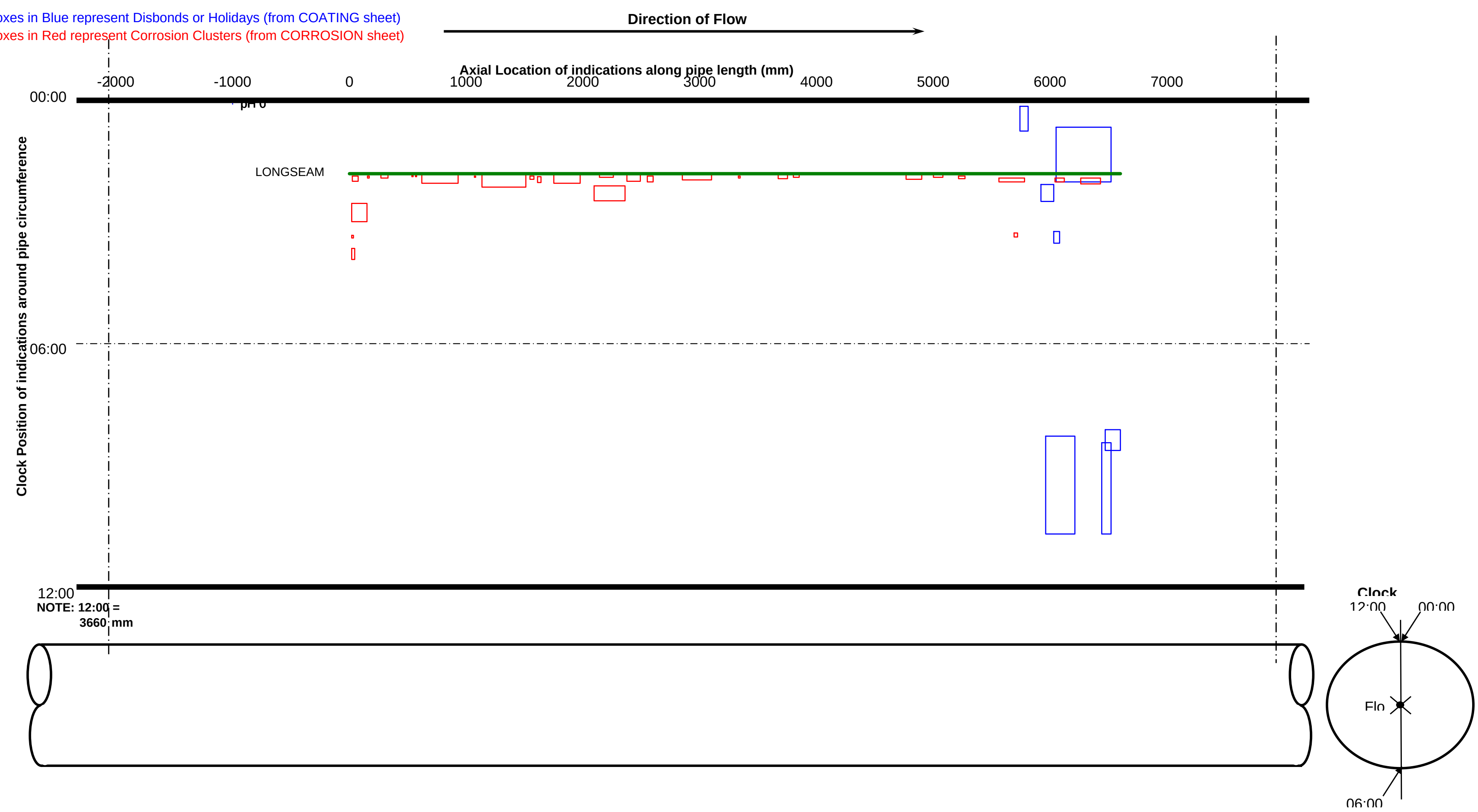
Coating and Corrosion Diagram

NDT Inspector

NDT Company Canspec Group Inc.

Pipe Rollout

Boxes in Blue represent Disbonds or Holidays (from COATING sheet)
Boxes in Red represent Corrosion Clusters (from CORROSION sheet)



CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Stress Corrosion Cracking Assessment

SCC Found ☐ Yes ☑ No

SCC Feature Number	ILI Area Number (From Data Sheets)	Feature Areas Inspected	Axial Start of Colony (mm)	Axial End of Colony (mm)	Axial Length of Colony (mm)	Circ Start of Colony (mm)	Circ End of Colony (mm)	Circ Width of Colony (mm)	O'Clock From	O'Clock To	Average Crack Length (mm)	Max Crack Length (mm)	Interacting Axially (Y/N)	Interacting Circ (Y/N)	Longest Interacting Crack Length (mm)	Max Crack Depth (mm)	Max Crack Depth (%)	Significant SCC Colony (Y/N)	Cracking associated with Corrosion (Y/N)	Depth of Colony [Corr. + Crack] (mm)	Depth of Colony [Corr. + Crack] (%)	Was SCC Removed (Y/N)	Type of Repair	Corresponding Feature(s)	Figure Number

SCC Comments No SCC was found in the area of NDE.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #1

AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Dent Assessment

Dent Feature Number	Corresponding Feature(s)	Axial Start of Dent (mm)	Axial End of Dent (mm)	Axial Length of Dent (mm)	Circ Start of Dent (mm)	Circ End of Dent (mm)	Circ Width of Dent (mm)	O'clock From	O'clock To	U/S Pipe Dia. 0°	U/S Pipe Dia. 90°	D/S Pipe Dia. 0°	D/S Pipe Dia. 90°	At Dent Pipe Dia. 0° (DMIN)	At Dent Pipe Dia. 90° (DMAX)	Max Diameter Reduction (Dnom-Dmax)	Ovality (Oval) Dmax Dnom	Half Ovality (Ohalf) 1/2*Oval	Eff. Dent (B) (Rmax-Ohalf)	Dent %	Is the dent sharp? (Y/N)	Is there wall thinning? (Y/N)	Possible Reasons For Dent As Observed

Dent

No dents were found in the area of NDE.

CANSPEC

Pipeline Integrity Field Report

Trafalgar NPS 42 Dig #1
AGM: Chainage

Client: Union Gas
Date: October 24, 2005
Girth Weld: Chainage 399m

Equipment

ULTRASONICS

Scan Type ☑ A ☐ B ☑ Flaw ☑ Thickness ☐ FAST™

Instrument				Transducer	Type Single	Type Dual	Frequency (MHz)	Serial #
Manufacturer	Krautkramer Branson USN52L			0°	☑	☐	15	1685
Serial #	00W566			60°	☑	☐	5	00YY8Y
Cal. Due Date	7-Dec-05			60°	☑	☐	10	0126FR
Range	Various			0°	☐	☑	7.5	FH2E
Transfer Value					☐	☐		
Cal Block	Step Wedge	S/N	113		☐	☐		
Cal Block	Rompas Block	S/N	99-693		☐	☐		
				Other:	☐	☐		
Couplant	Sonoglide Gr 20			Other:	☐	☐		

Scan Type ☐ A ☐ B ☐ Flaw ☐ Thickness ☐ FAST™

Instrument				Transducer	Type Single	Type Dual	Frequency (MHz)	Serial #
Manufacturer					☐	☐		
Serial #					☐	☐		
Cal. Due Date					☐	☐		
Range					☐	☐		
Transfer Value					☐	☐		
Cal Block		S/N			☐	☐		
Cal Block		S/N			☐	☐		
				Other:	☐	☐		
Couplant				Other:	☐	☐		

MAGNETIC PARTICLE

MPI Equipment

Manufacturer	Type	S/N	Cal. Due Date
Parker	B 300UF	9452	30-Nov-05

Magnetizing Method ☑ AC or ☐ DC ☑ Continuous or ☐ Residual ☑ Yoke ☐ Coil

	Name	Signature	CGSB Number
Technician	James Allen	On File	10019
Technician	Joseph Lui	On File	

NPS 42 Trafalgar Site 1 Photographs

01) West View of Excavation

02) East View of Excavation

NPS 42 Trafalgar Site 1 Photographs

03) South East View of Excavation

04) North East View of Excavation

NPS 42 Trafalgar Site 1 Photographs

05) West View of Excavation

06) North West View of Excavation

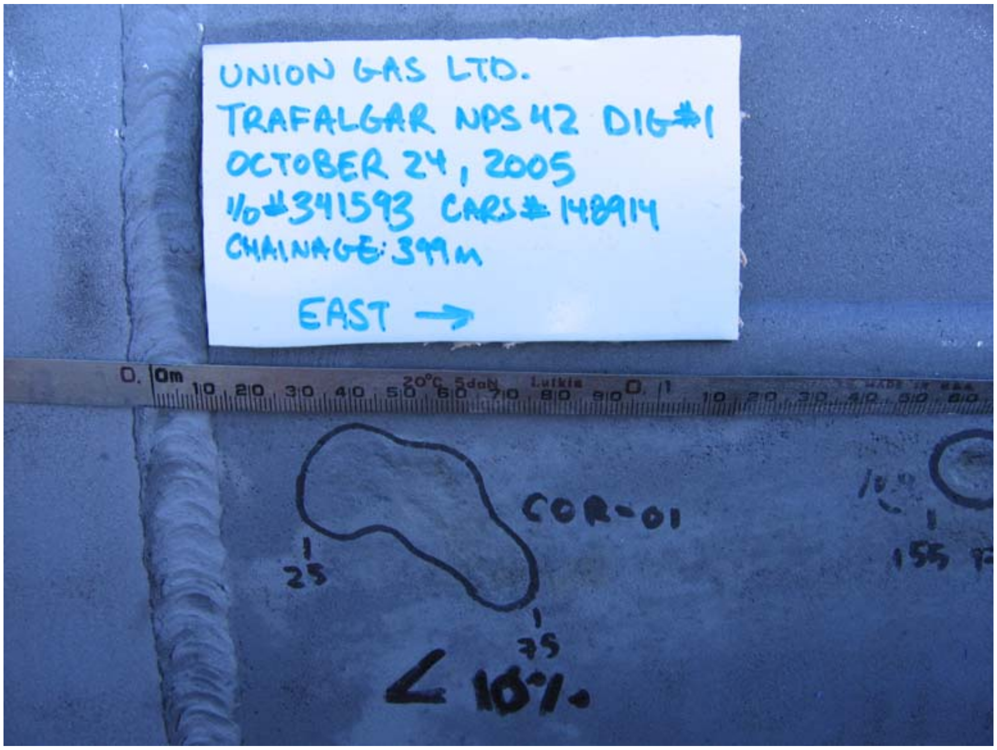
NPS 42 Trafalgar Site 1 Photographs

07) South West View of Excavation

08) Soil Spill Pile

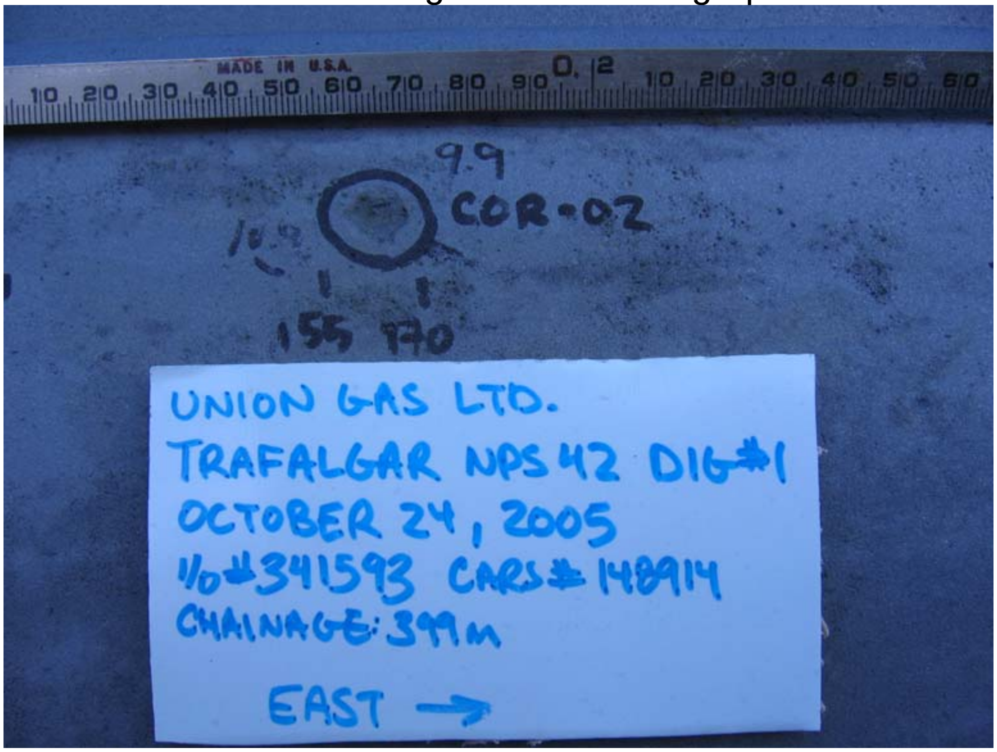
NPS 42 Trafalgar Site 1 Photographs

09) Soil

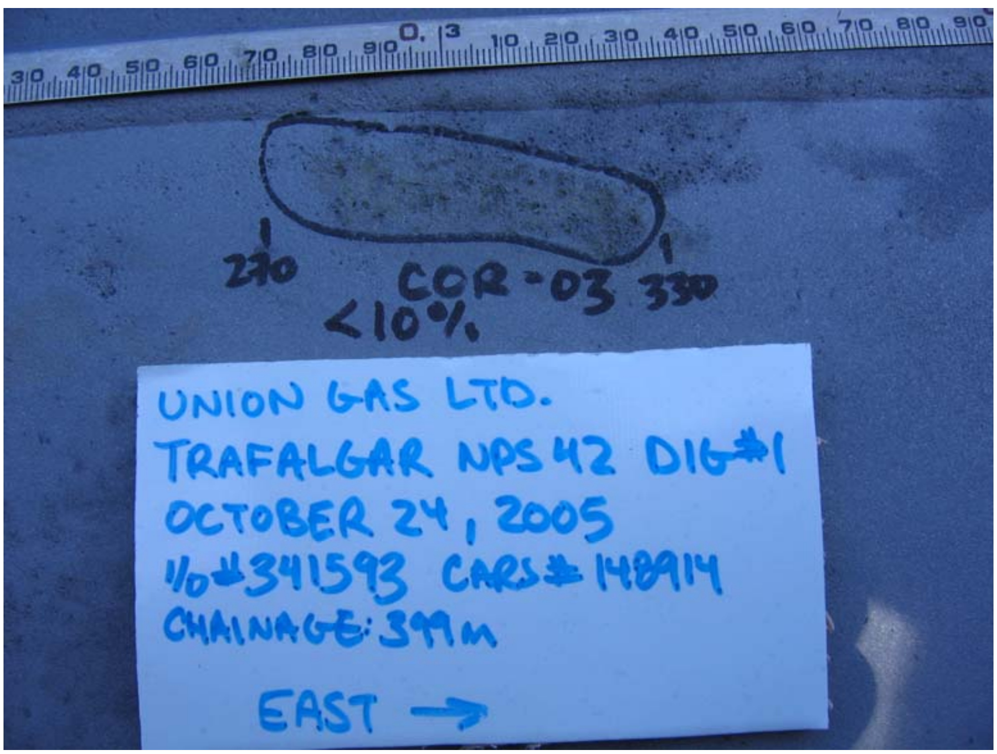


10) COR-01

NPS 42 Trafalgar Site 1 Photographs

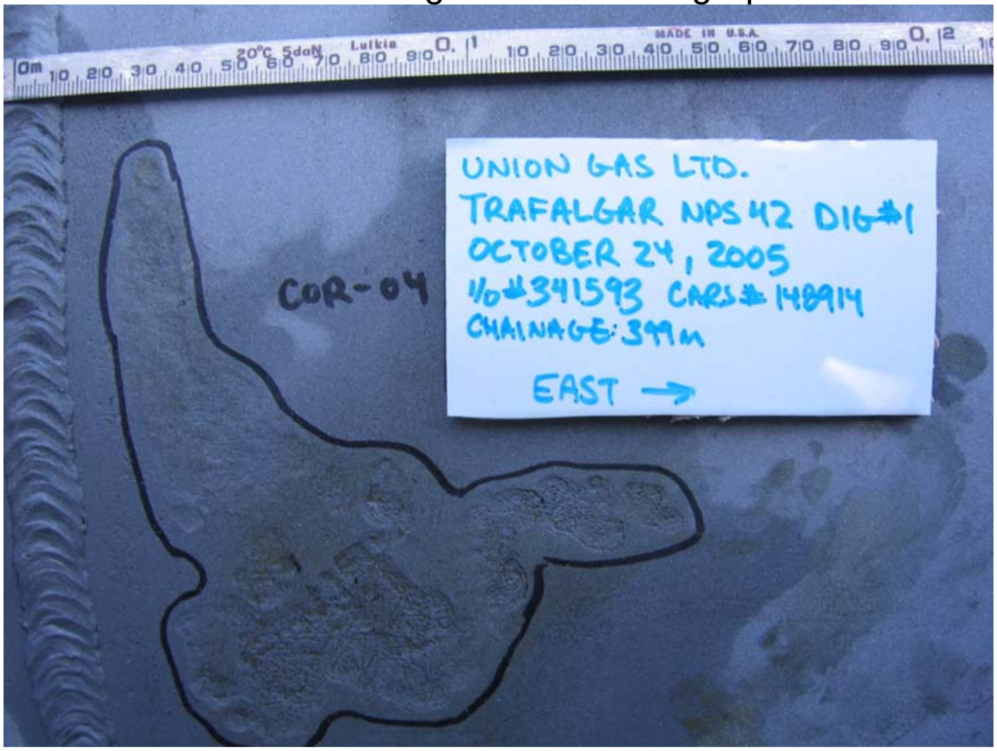


11) COR-02

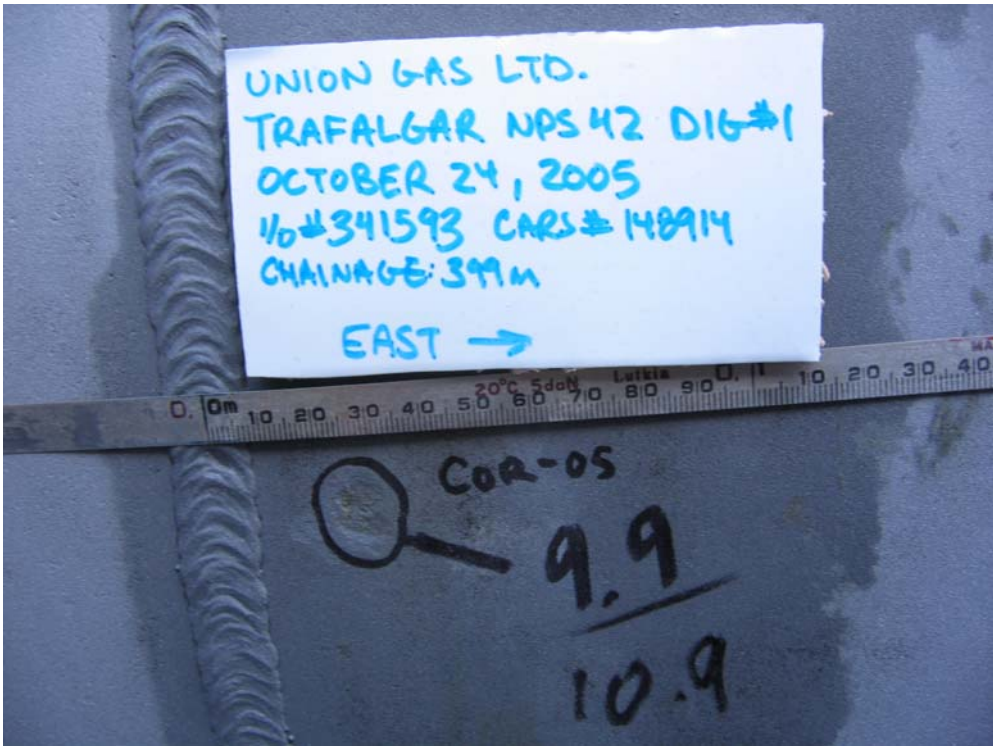


12) COR-03

NPS 42 Trafalgar Site 1 Photographs

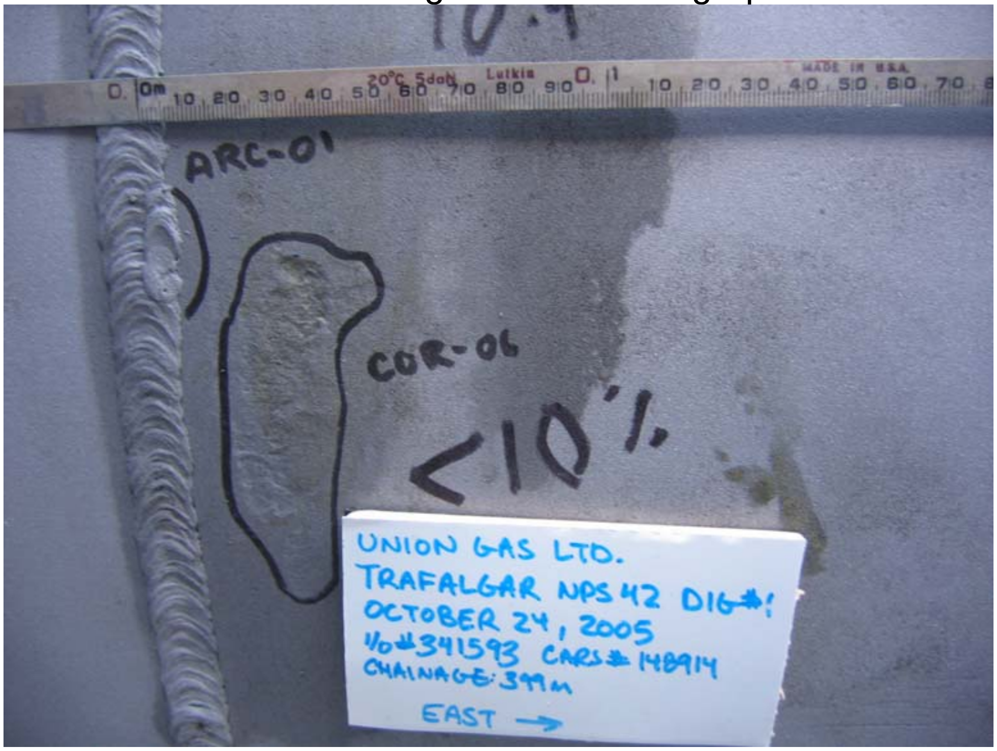


13) COR-04

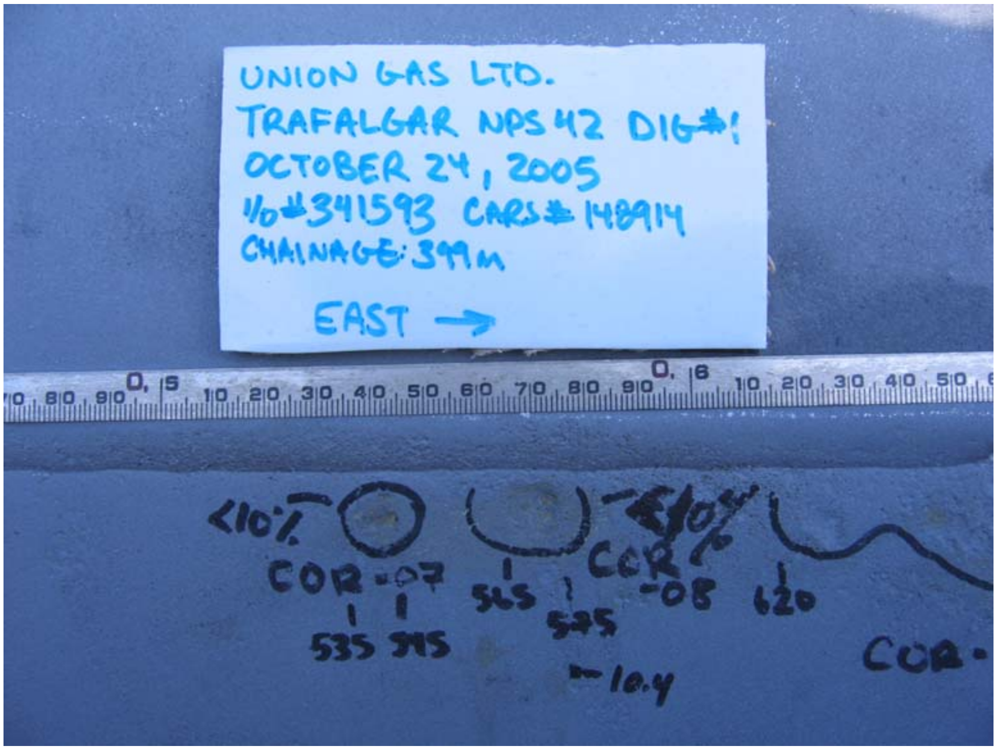


14) COR-05

NPS 42 Trafalgar Site 1 Photographs

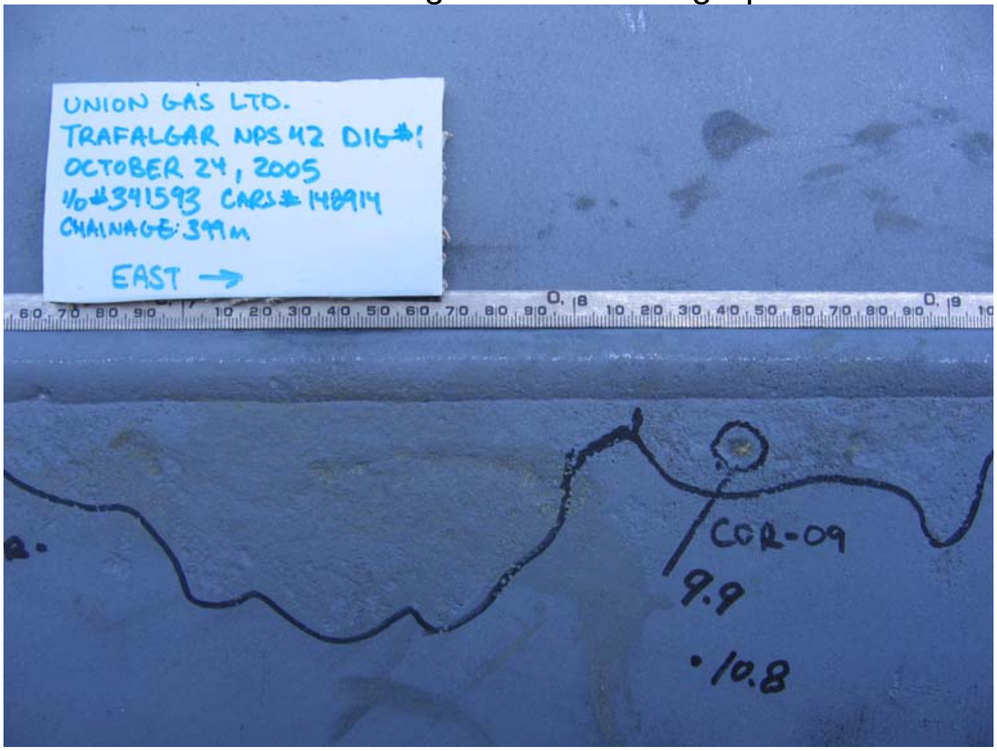


15) COR-06, ARC-01

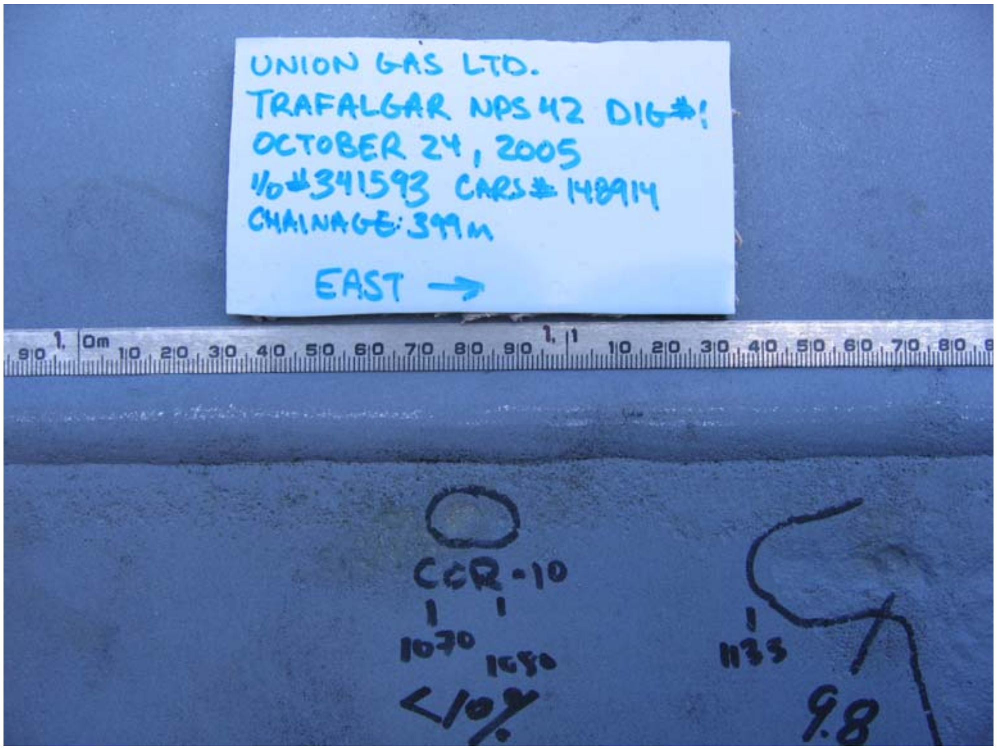


16) COR-(07,08)

NPS 42 Trafalgar Site 1 Photographs



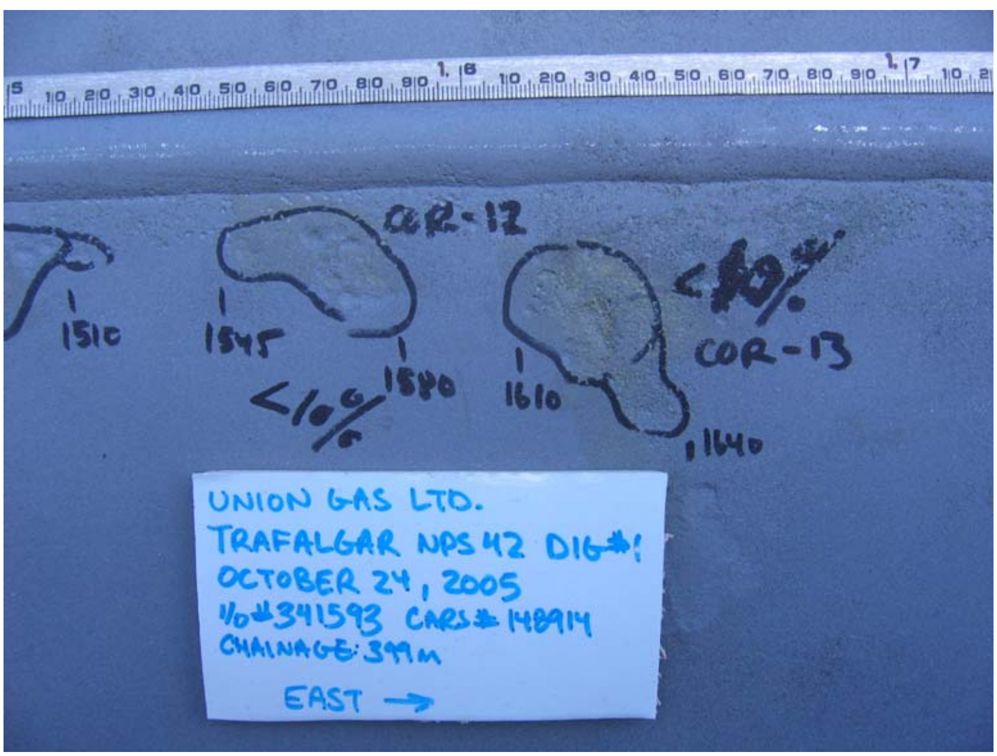
17) COR-09



18) COR-10

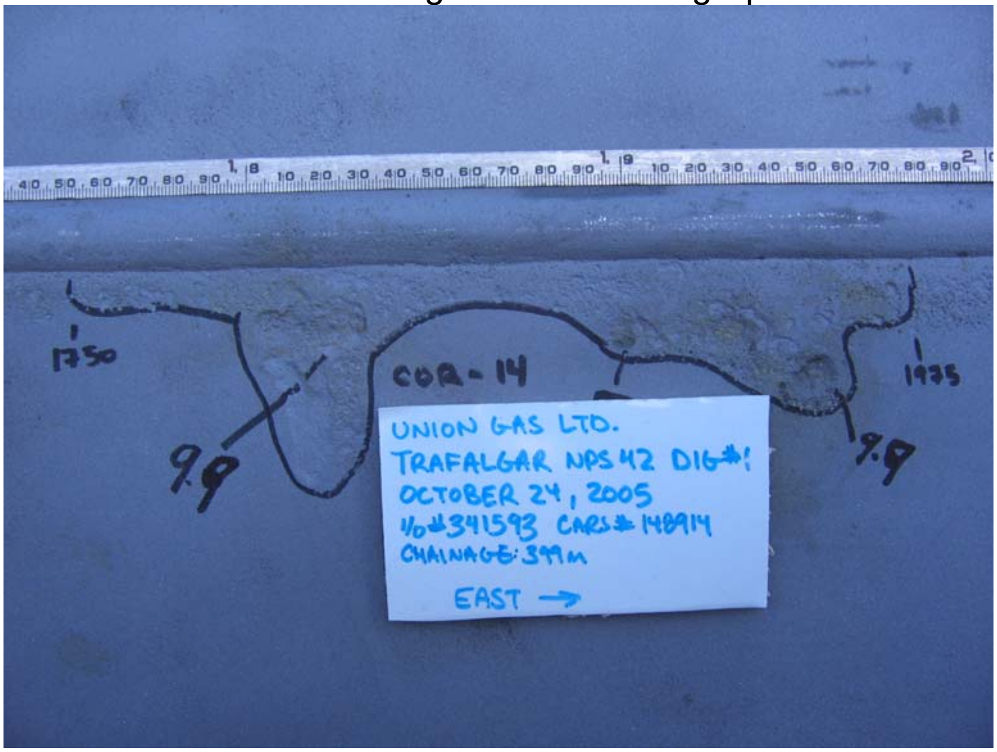
NPS 42 Trafalgar Site 1 Photographs

19) COR-11

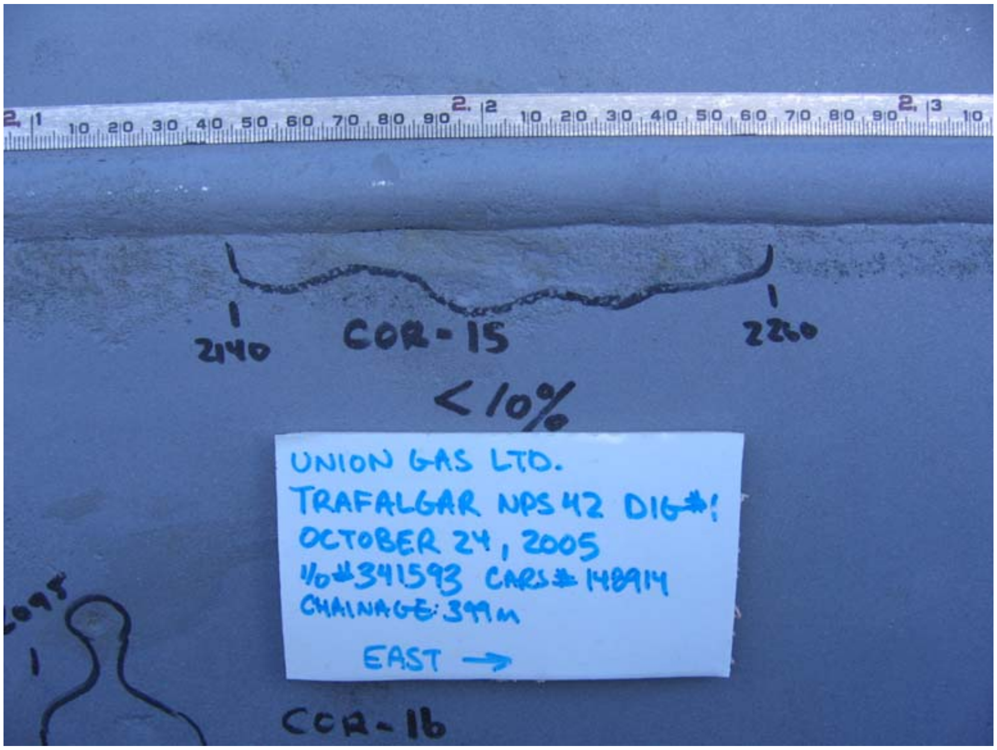


20) COR-(12,13)

NPS 42 Trafalgar Site 1 Photographs

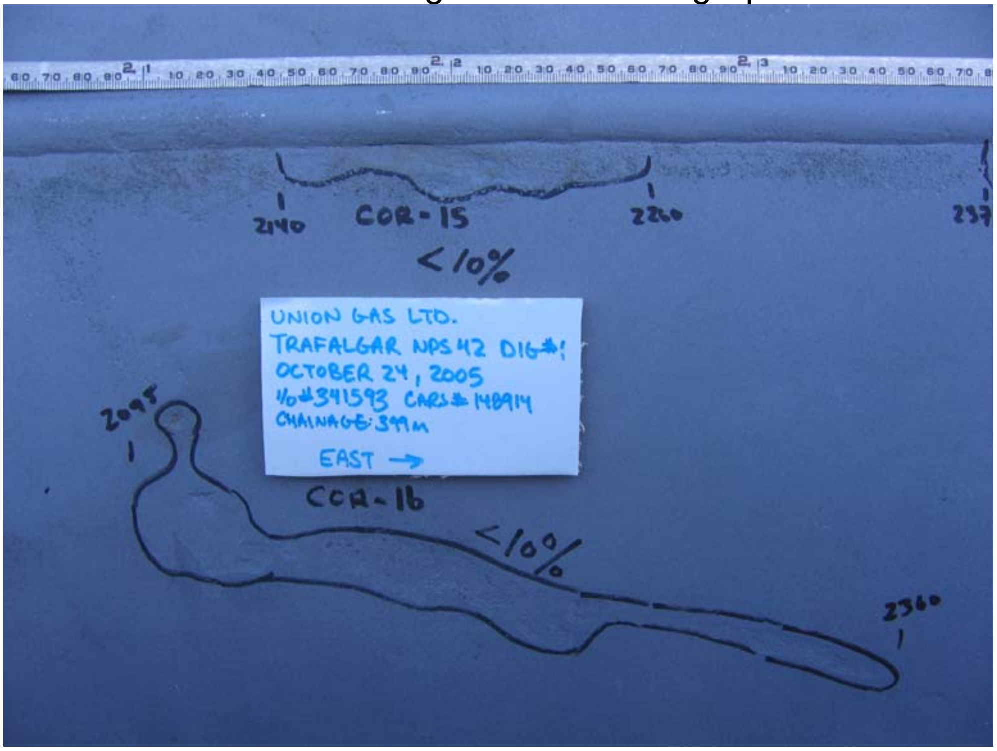


21) COR-14

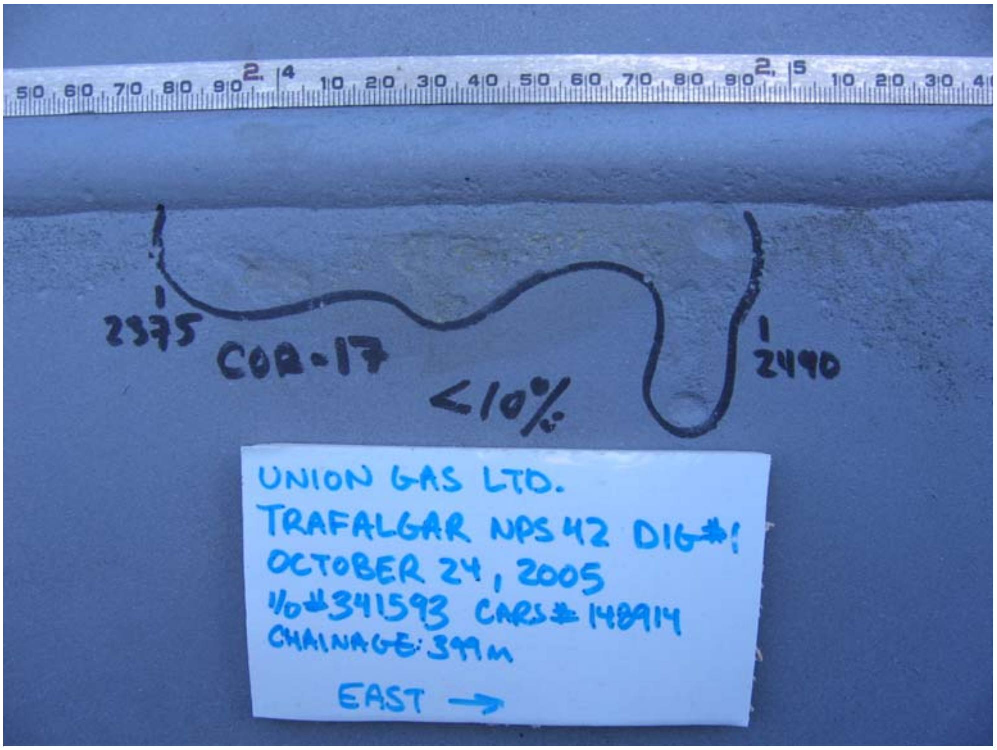


22) COR-15

NPS 42 Trafalgar Site 1 Photographs



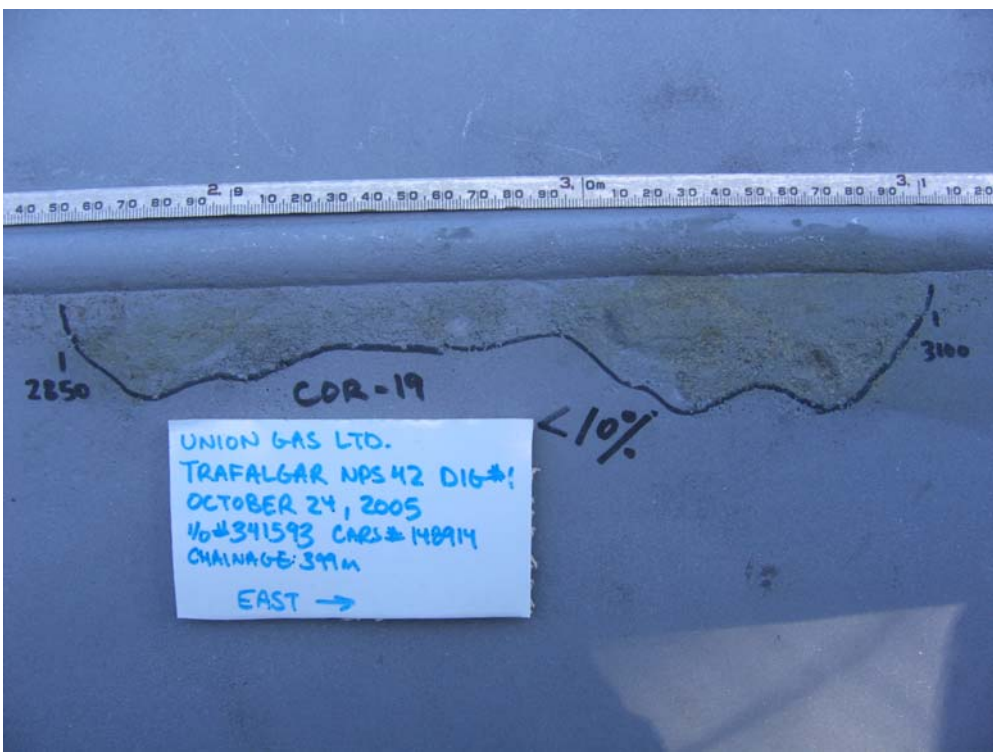
23) COR-16



24) COR-17

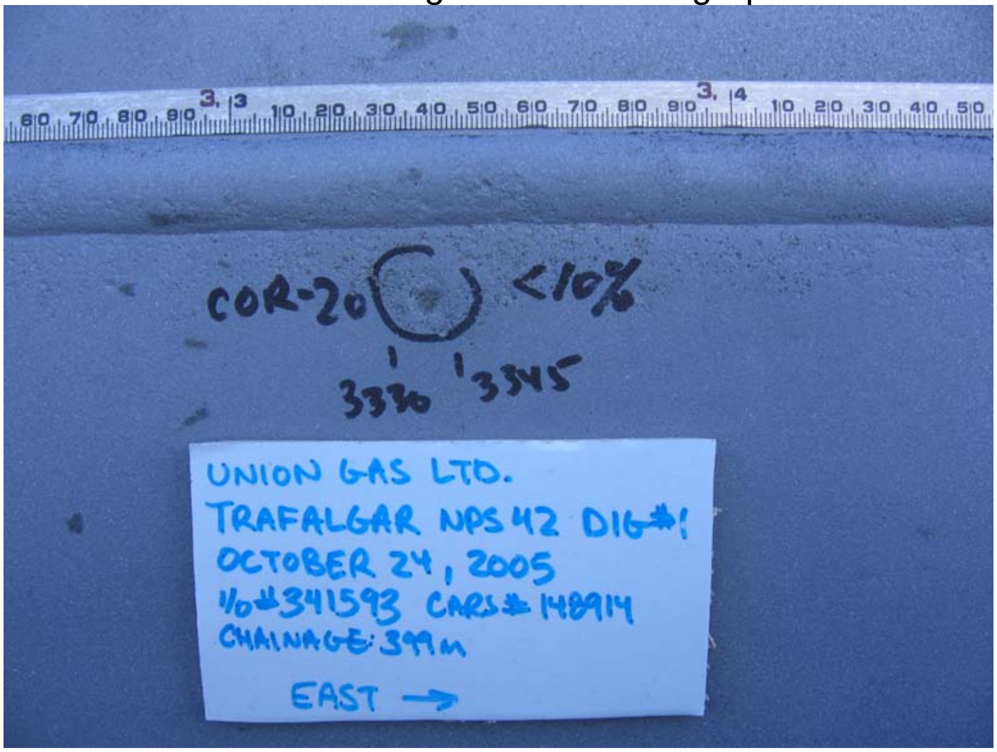
NPS 42 Trafalgar Site 1 Photographs

25) COR-18

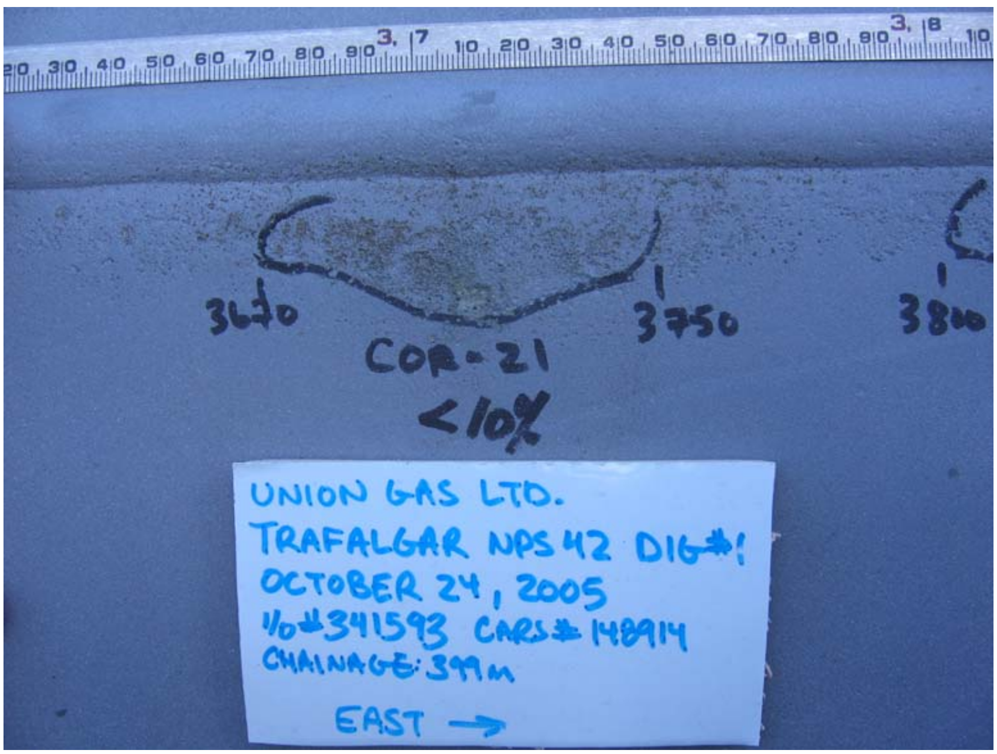


26) COR-19

NPS 42 Trafalgar Site 1 Photographs

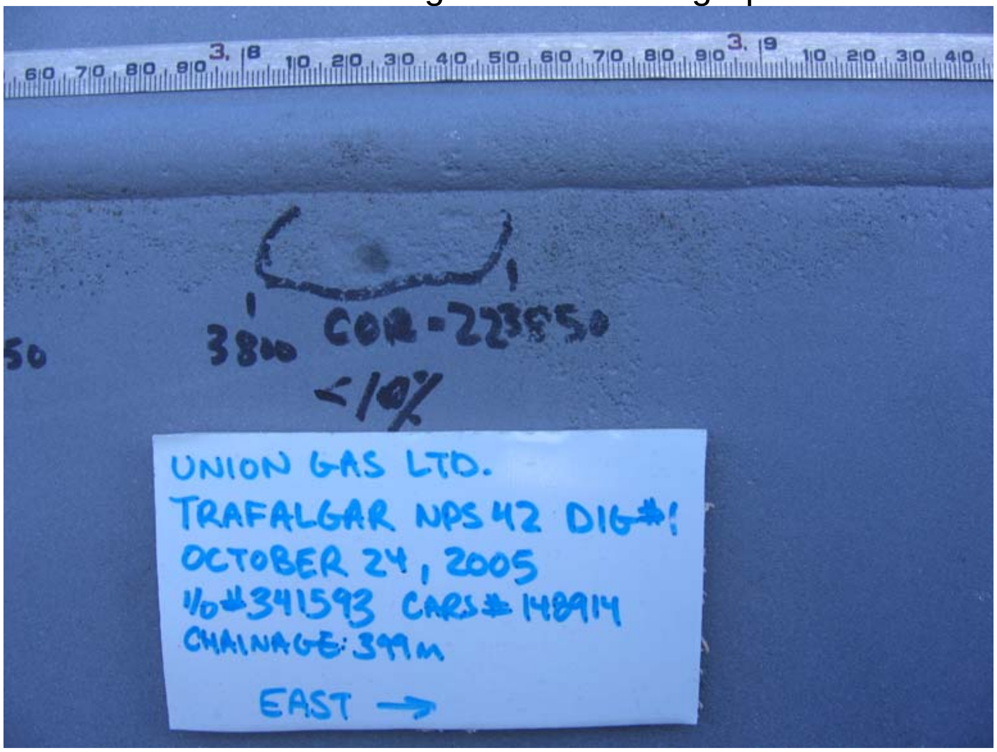


27) COR-20



28) COR-21

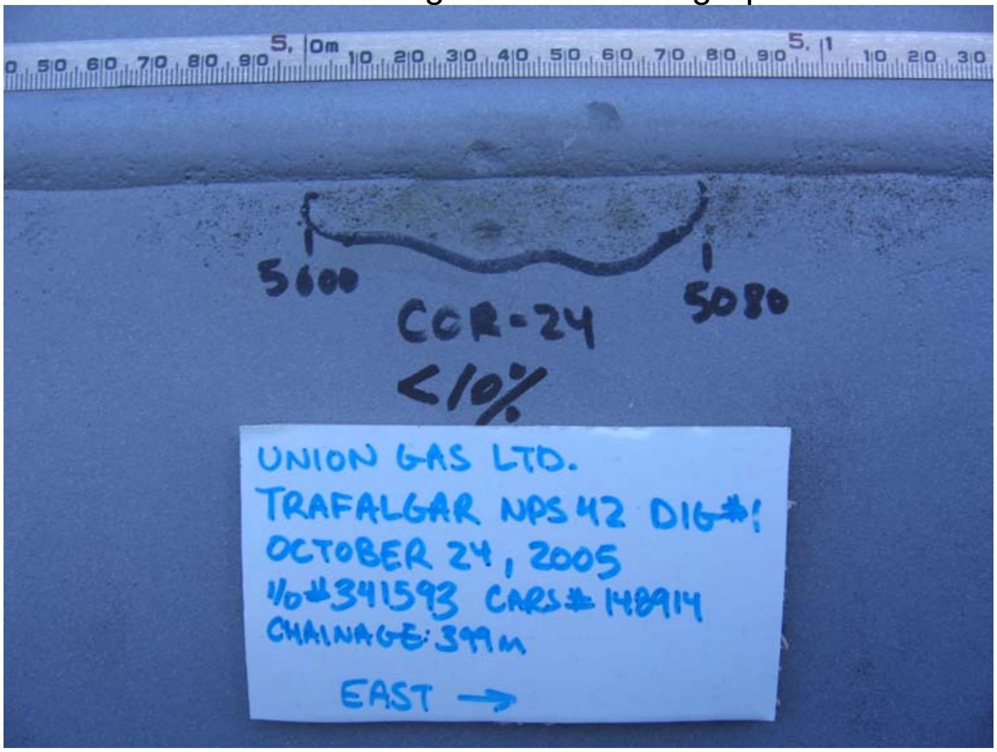
NPS 42 Trafalgar Site 1 Photographs



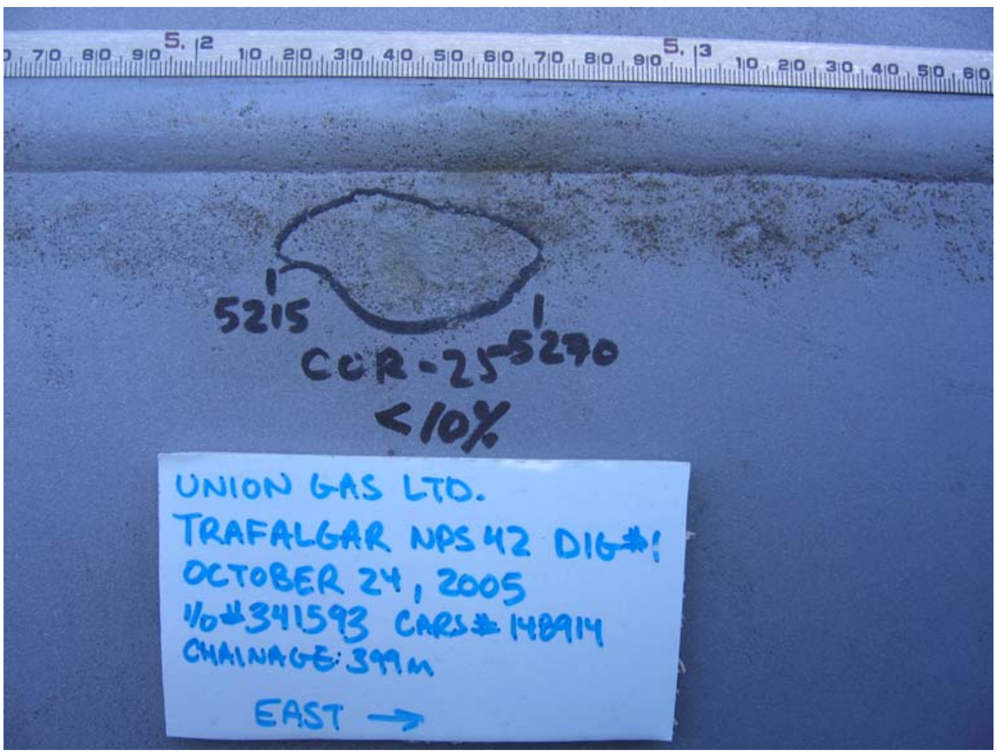
29) COR-22

30) COR-23

NPS 42 Trafalgar Site 1 Photographs

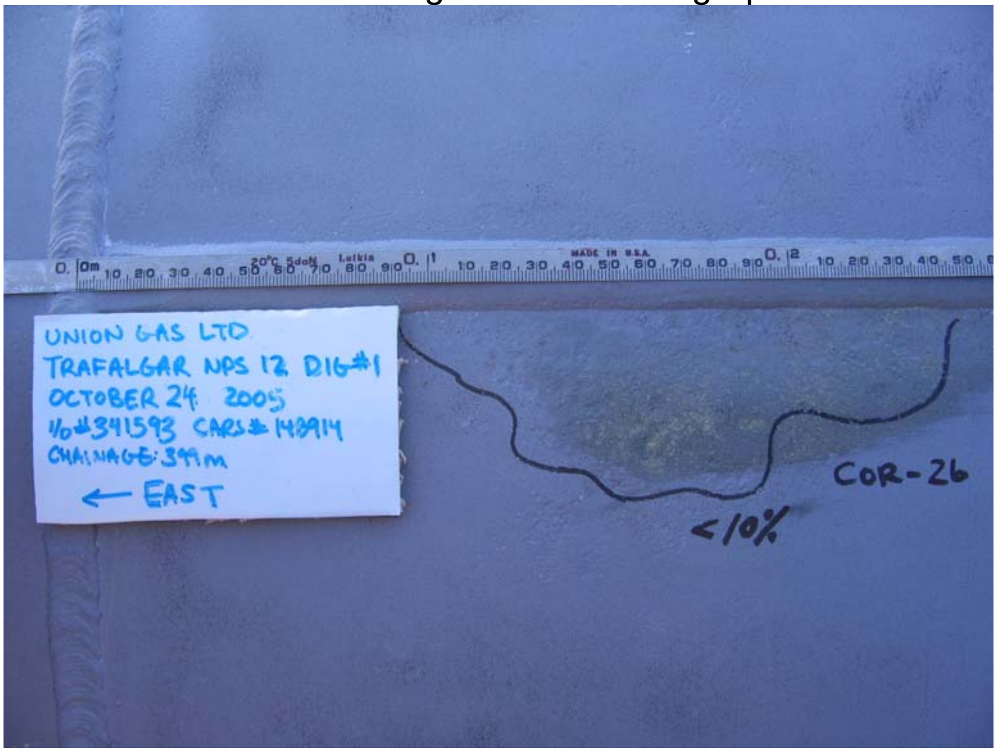


31) COR-24

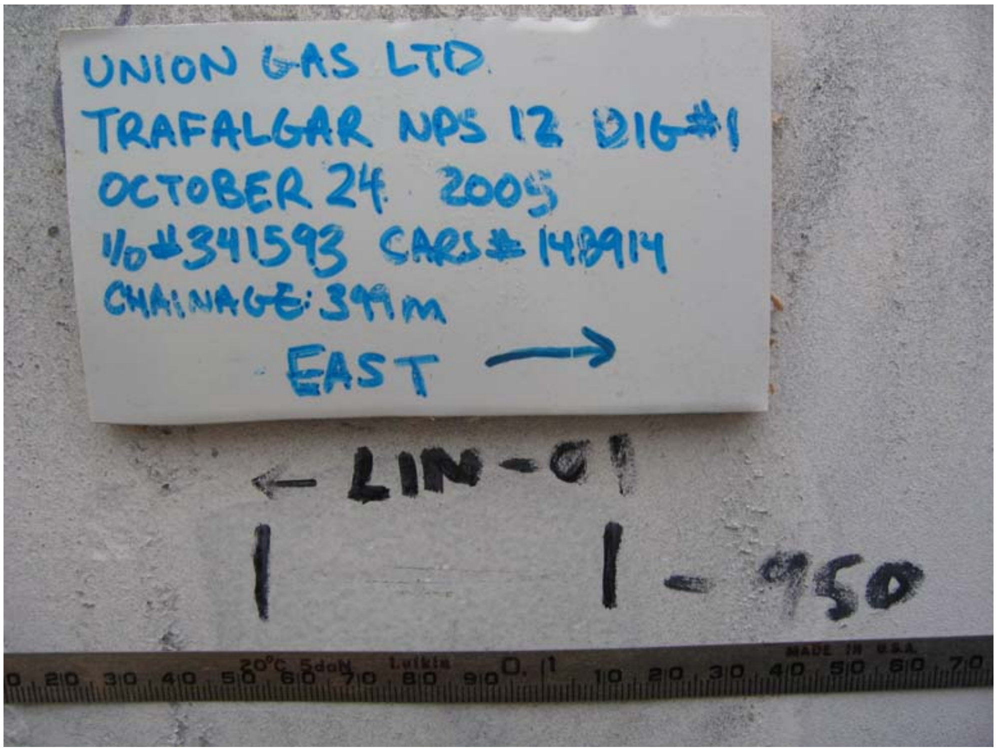


32) COR-25

NPS 42 Trafalgar Site 1 Photographs

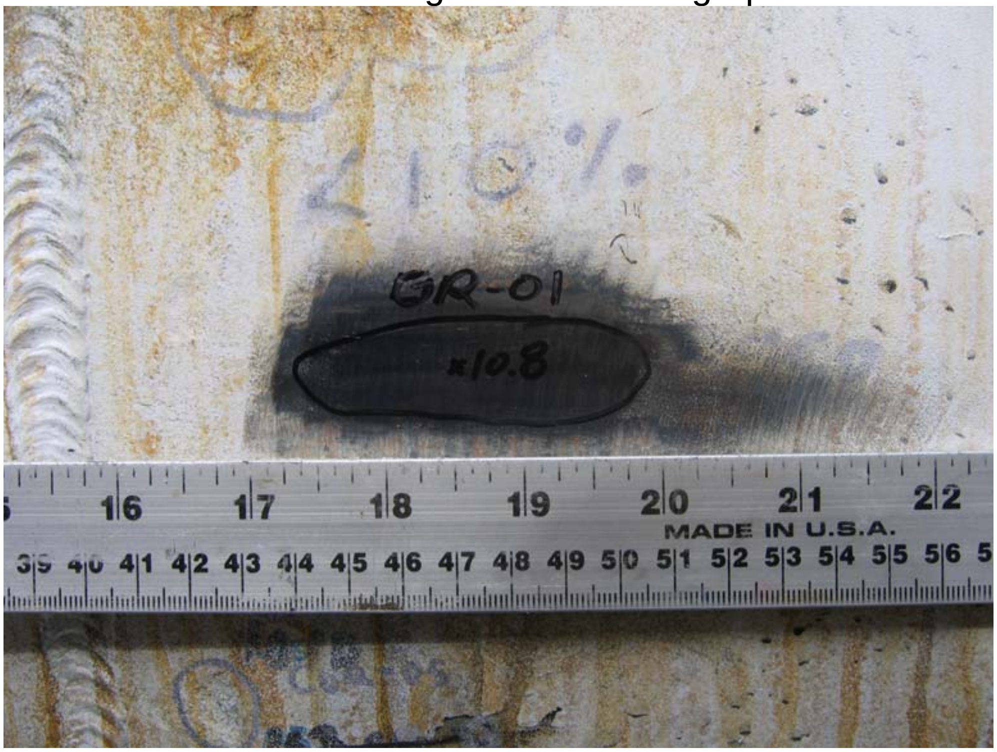


33) COR-26



34) LIN-01

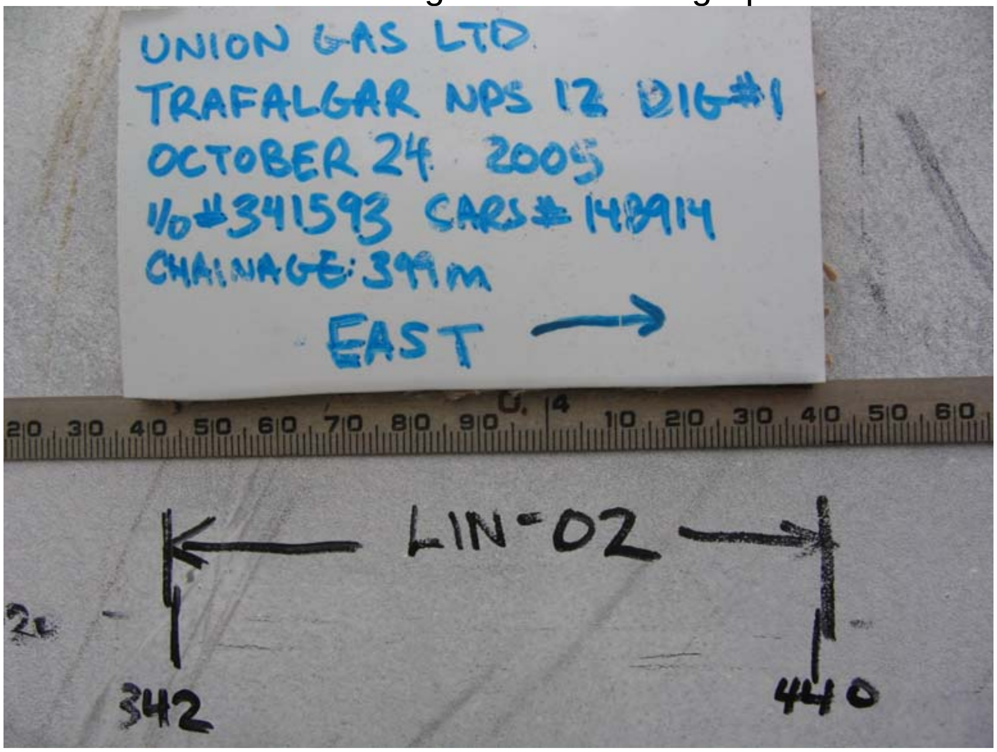
NPS 42 Trafalgar Site 1 Photographs



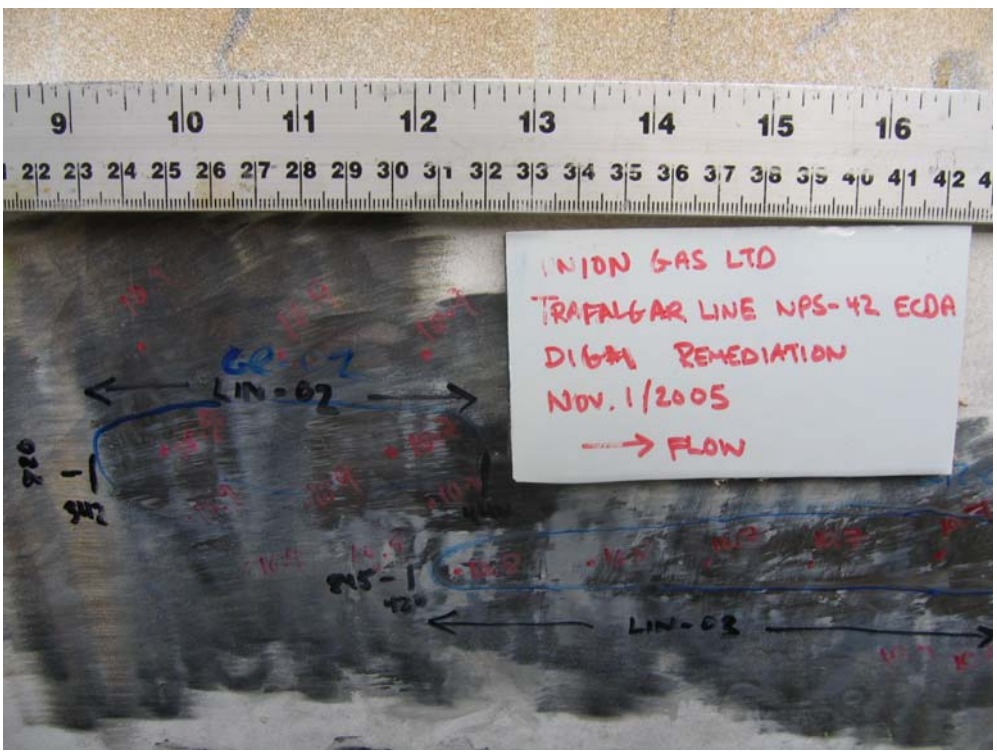
35) GR-01

36) GR-01 Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

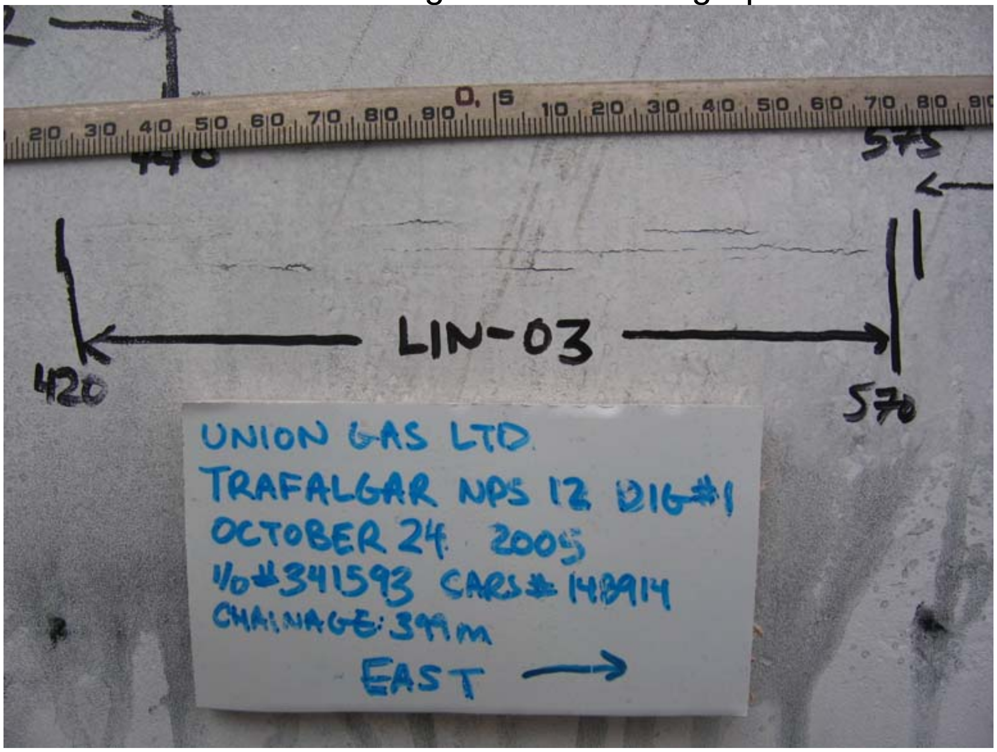


37) LIN-02

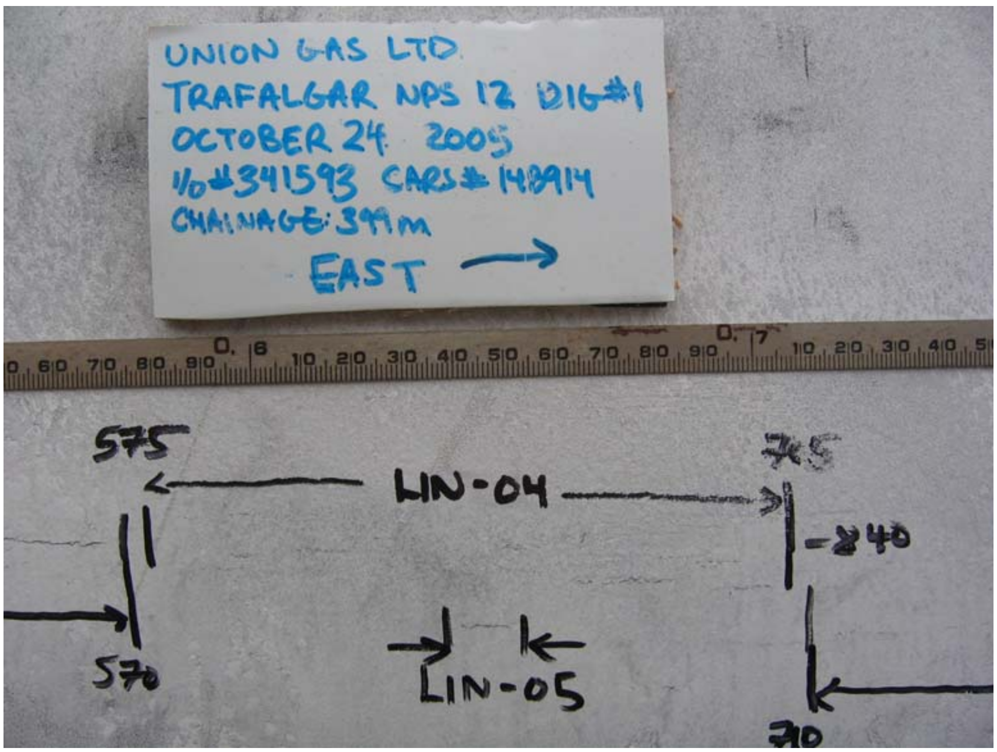


38) GR-02

NPS 42 Trafalgar Site 1 Photographs

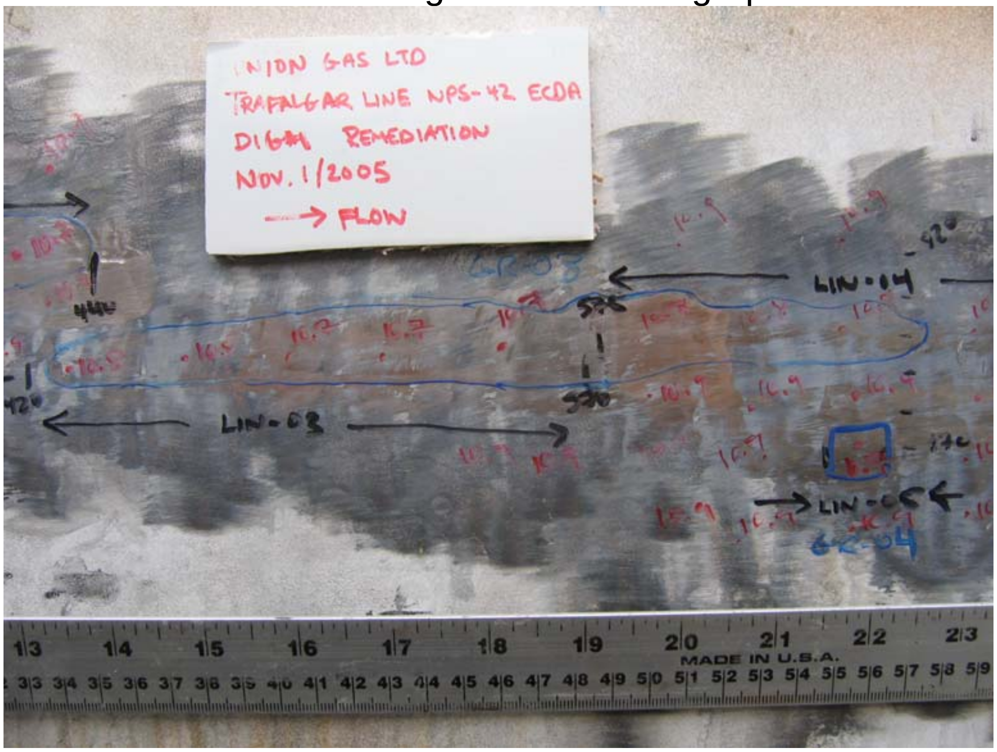


39) LIN-03



40) LIN-(04,05)

NPS 42 Trafalgar Site 1 Photographs



41) GR-03

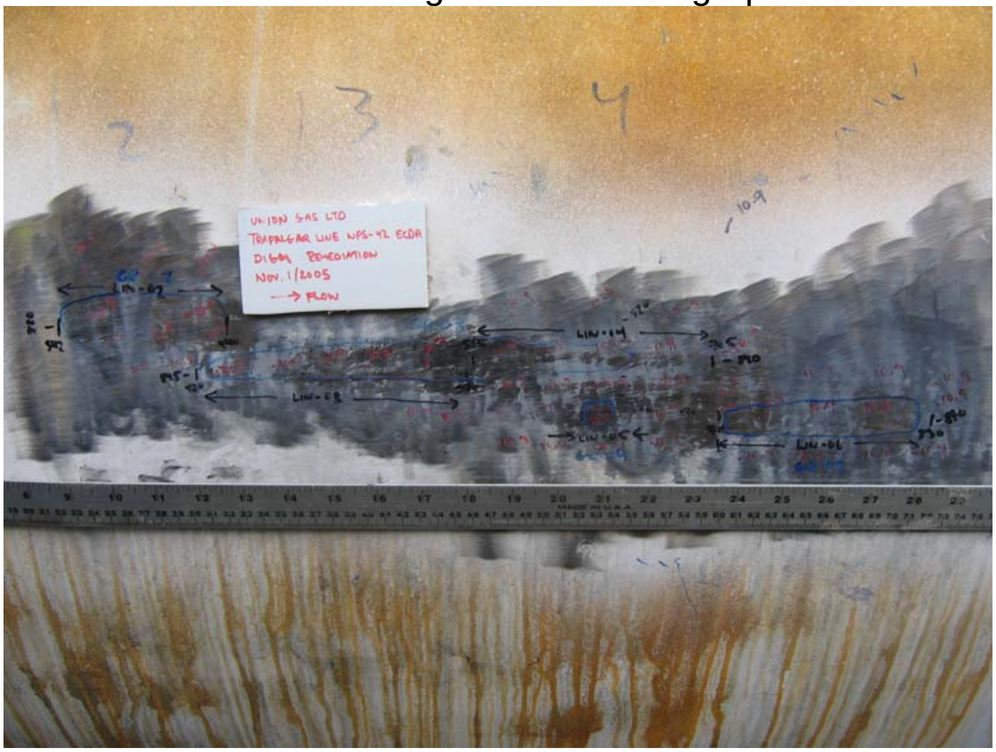
42) GR-04

NPS 42 Trafalgar Site 1 Photographs

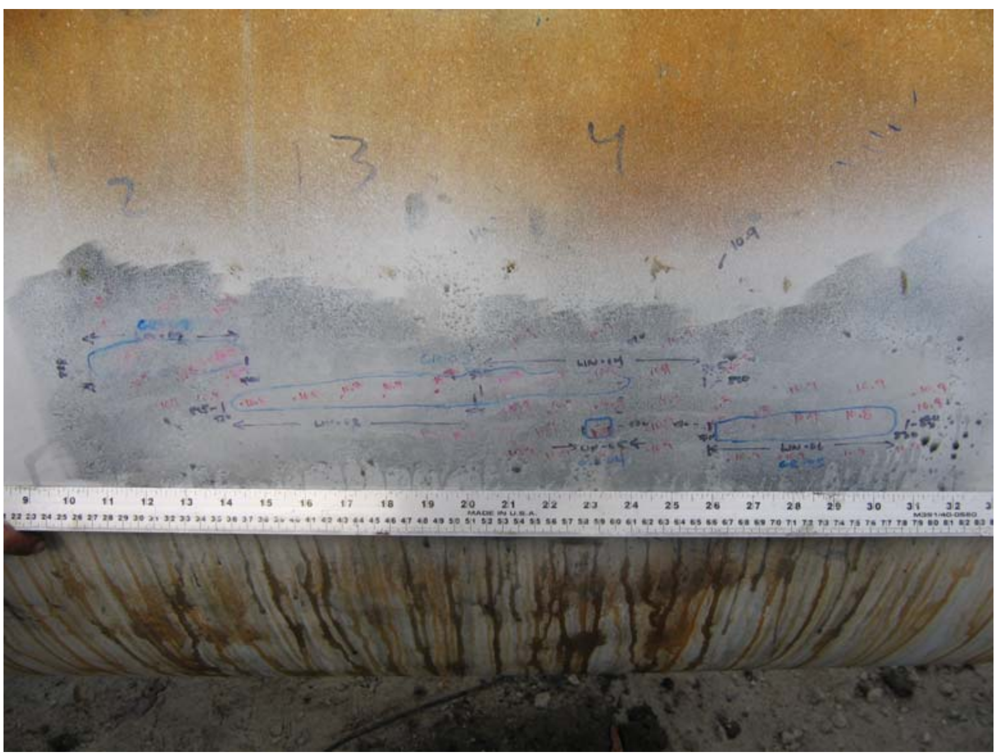
43) LIN-06

44) GR-05

NPS 42 Trafalgar Site 1 Photographs

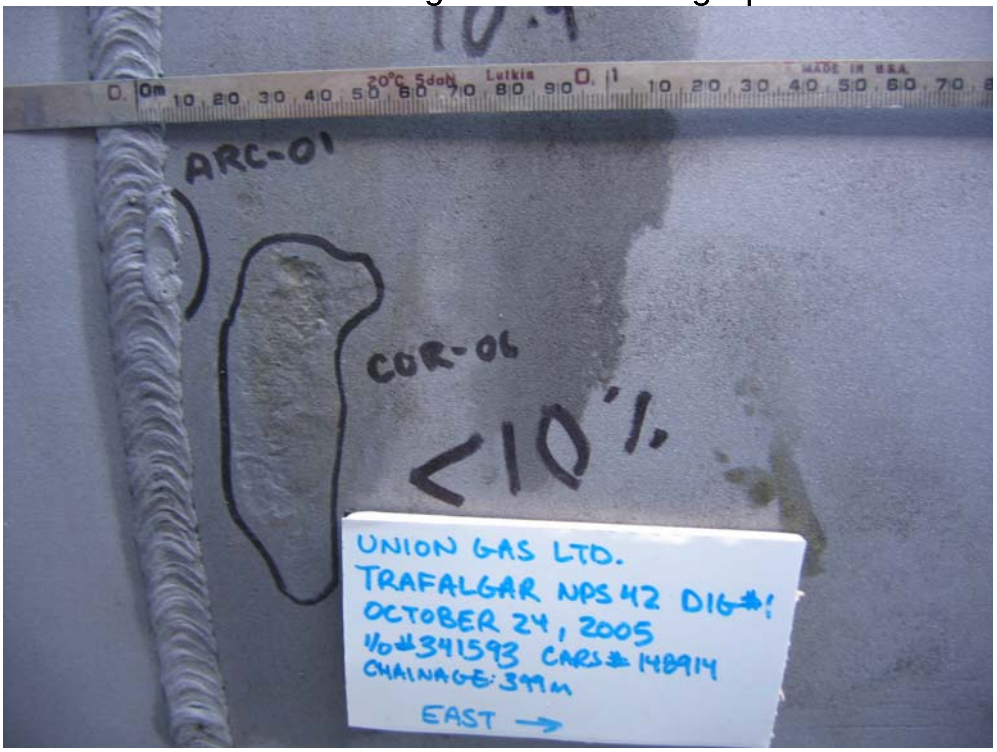


45) GR-(02,03,04,05) Linear Indications



46) GR-(02,03,04,05) Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

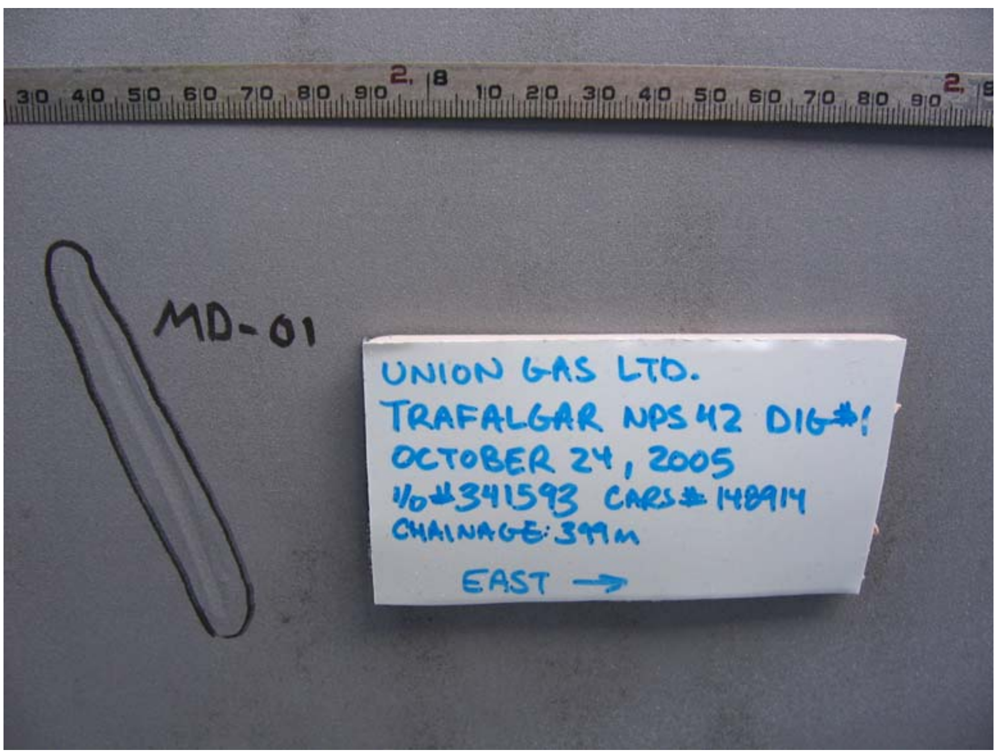


47) ARC-01

48) GR-06

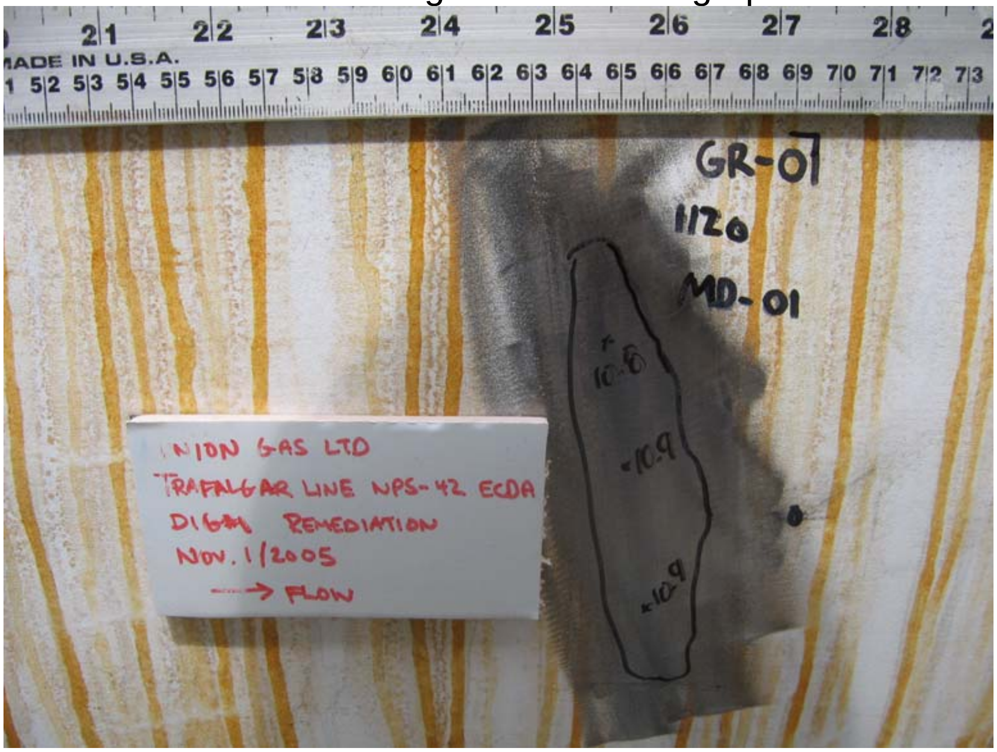
NPS 42 Trafalgar Site 1 Photographs

49) GR-06 Magnetic Particle

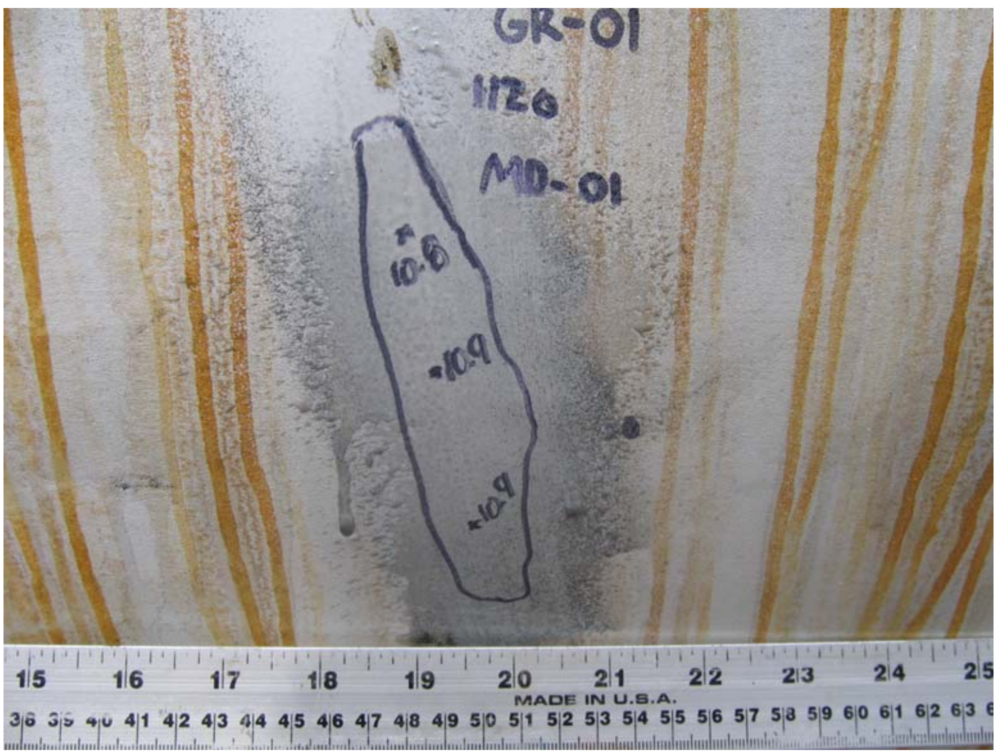


50) MD-01

NPS 42 Trafalgar Site 1 Photographs

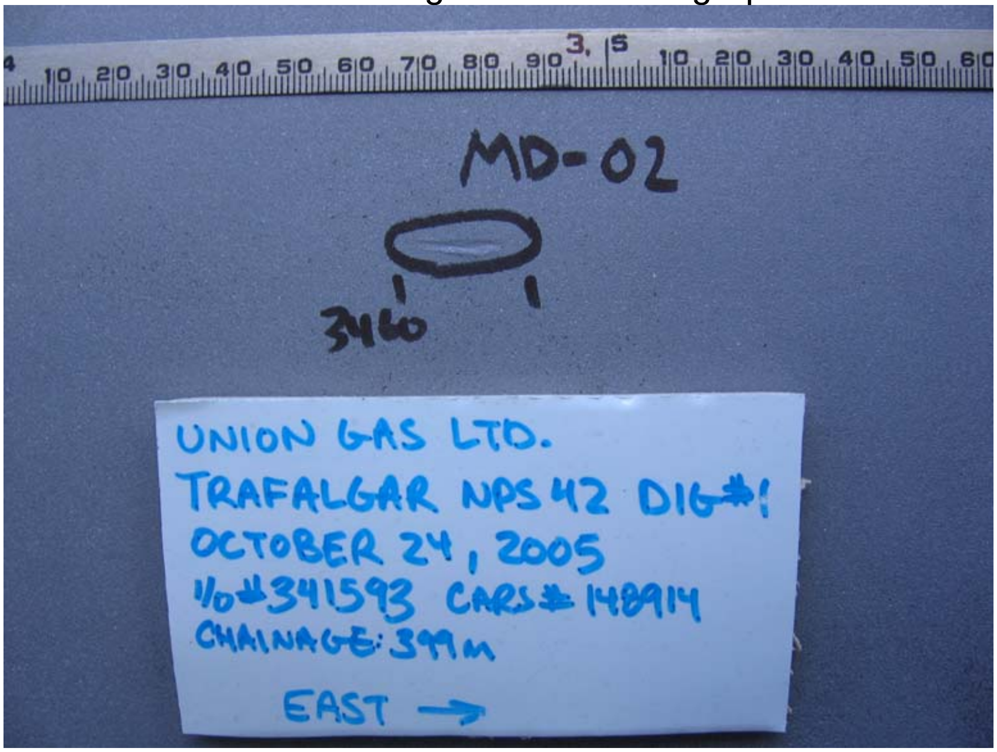


51) GR-07



52) GR-07 Magnetic Particle

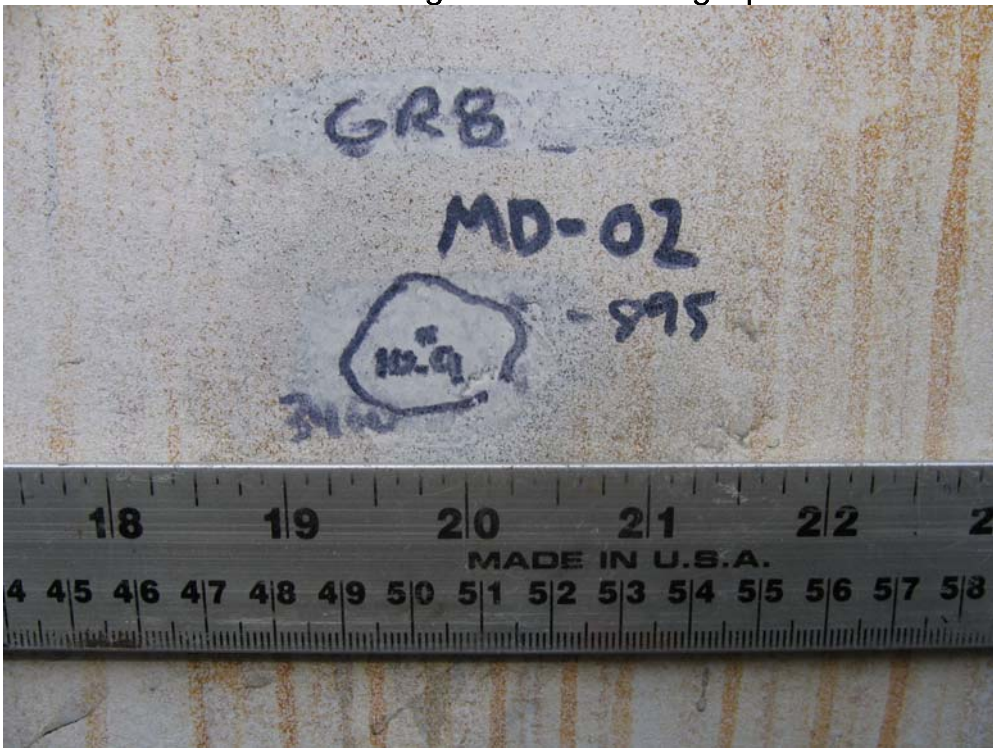
NPS 42 Trafalgar Site 1 Photographs



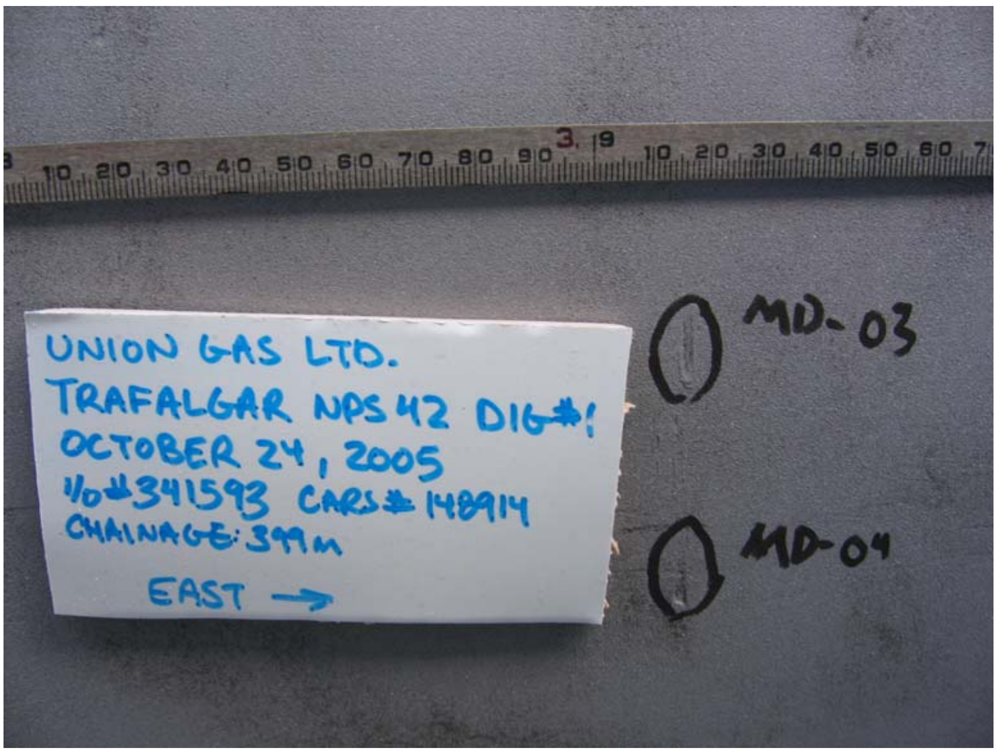
53) MD-02

54) GR-08

NPS 42 Trafalgar Site 1 Photographs

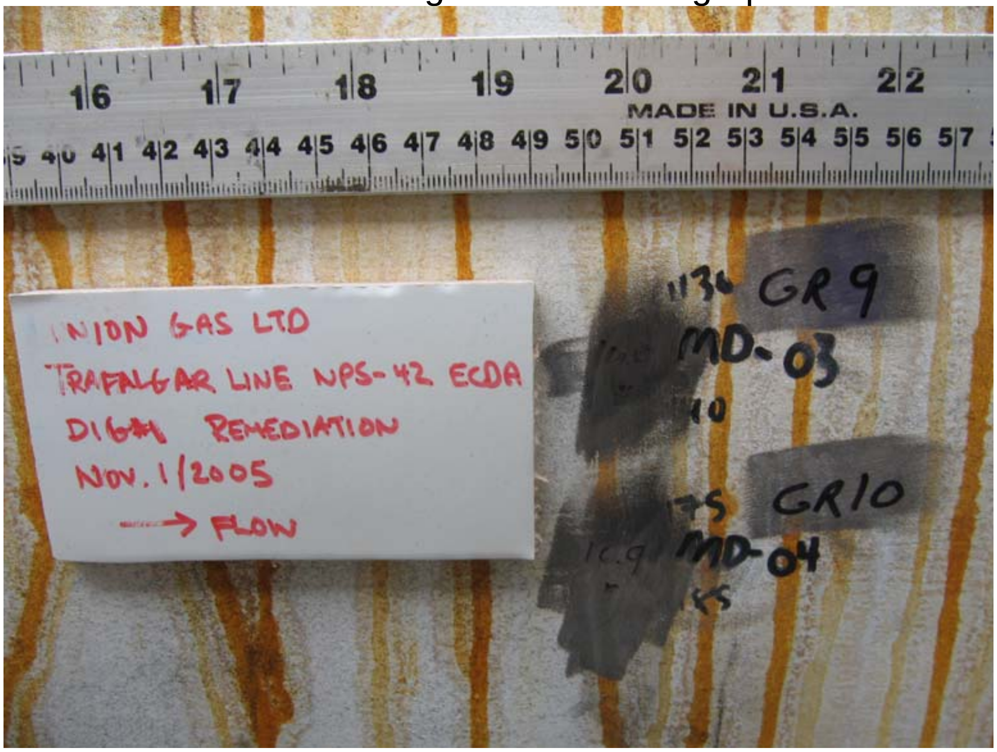


55) GR-08 Magnetic Particle

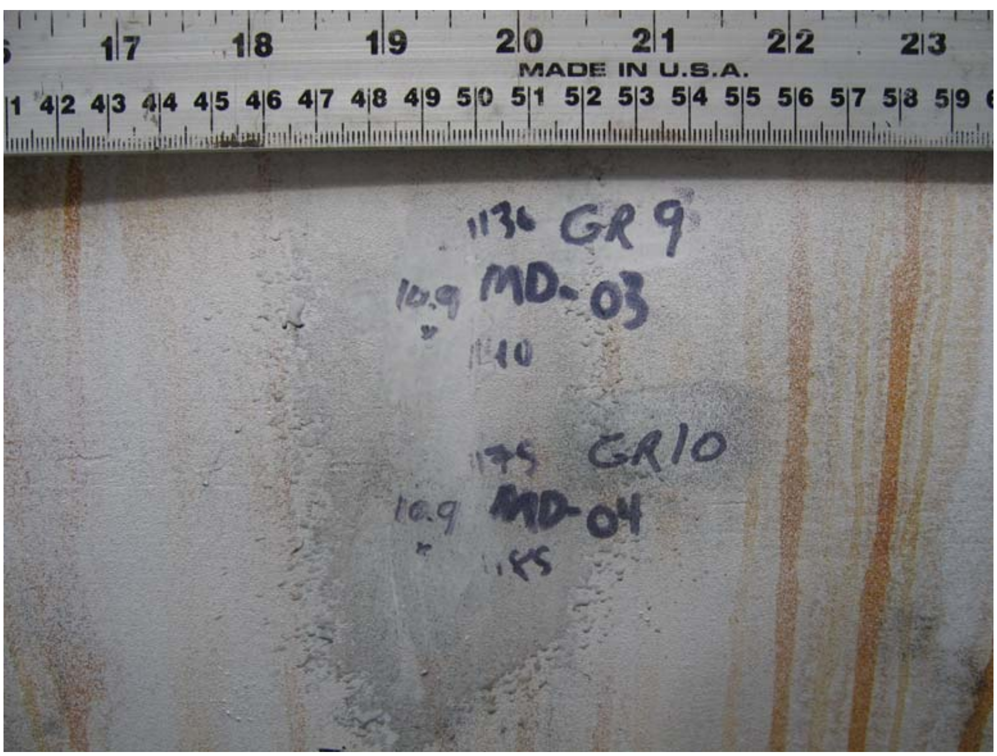


56) MD-(03,04)

NPS 42 Trafalgar Site 1 Photographs

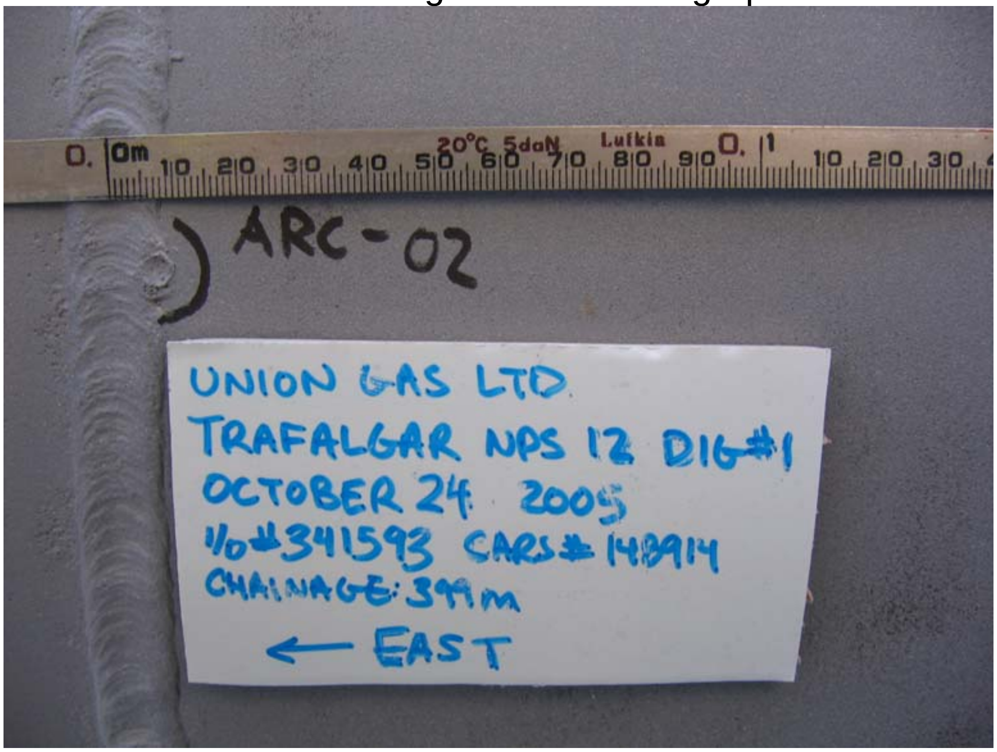


57) GR-(09,10)

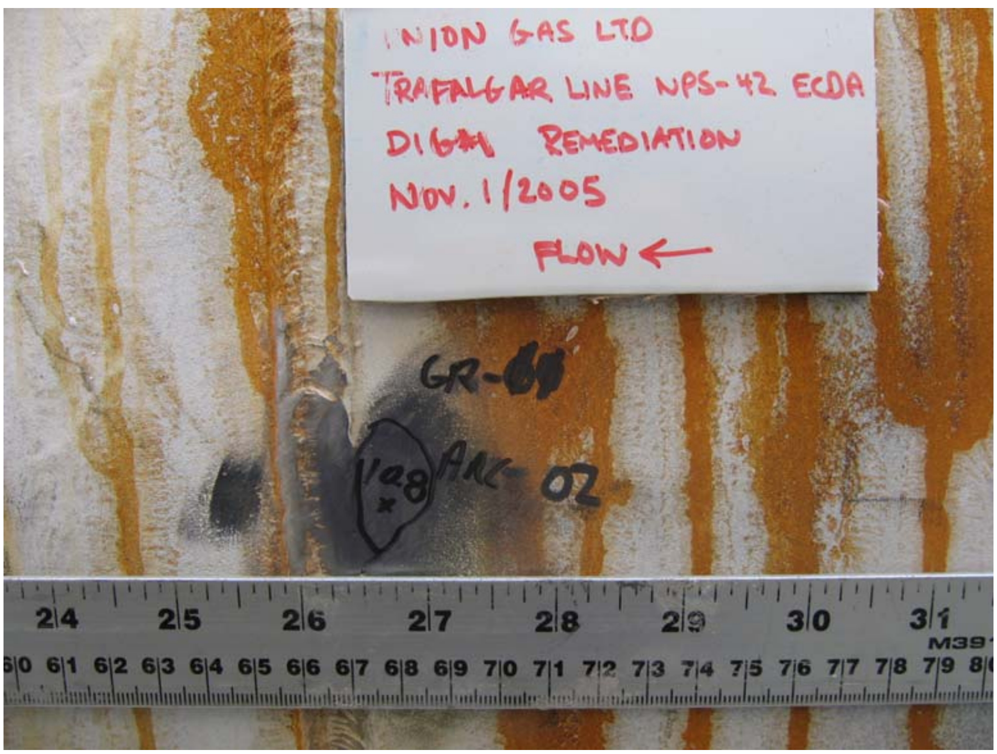


58) GR-(09,10) Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

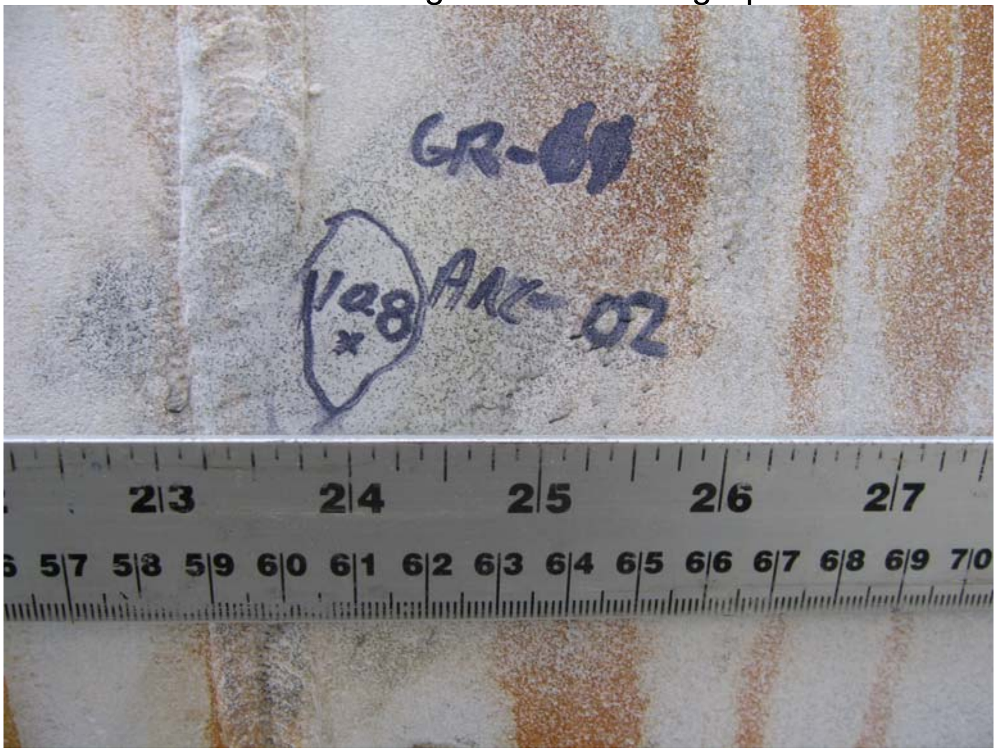


59) ARC-02

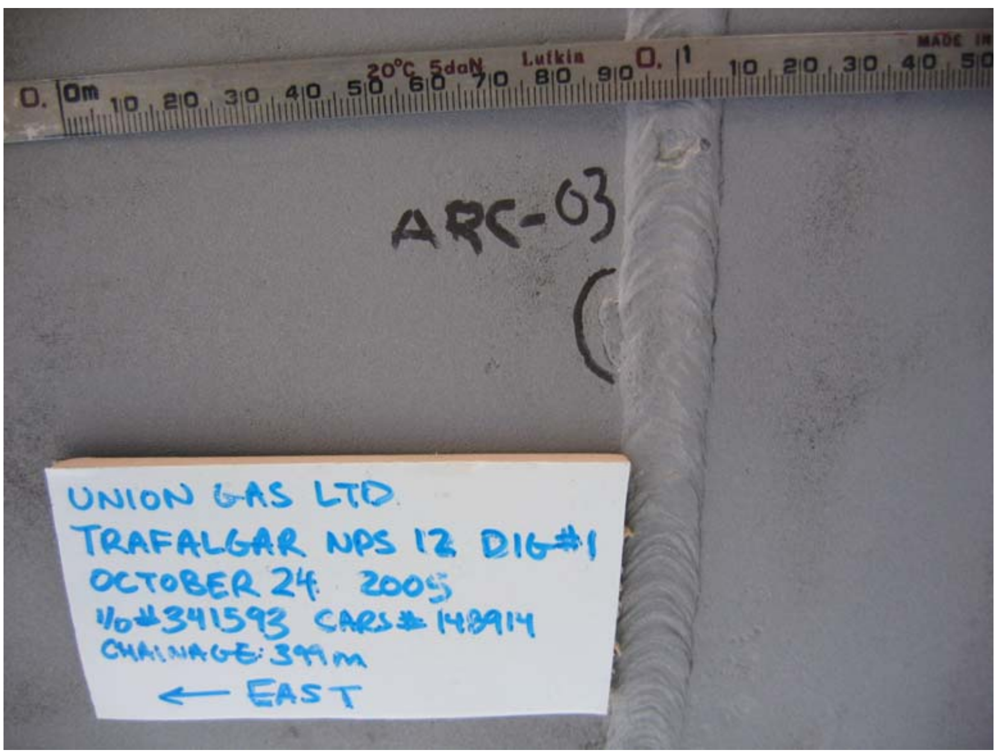


60) GR-11

NPS 42 Trafalgar Site 1 Photographs



61) GR-11 Magnetic Particle



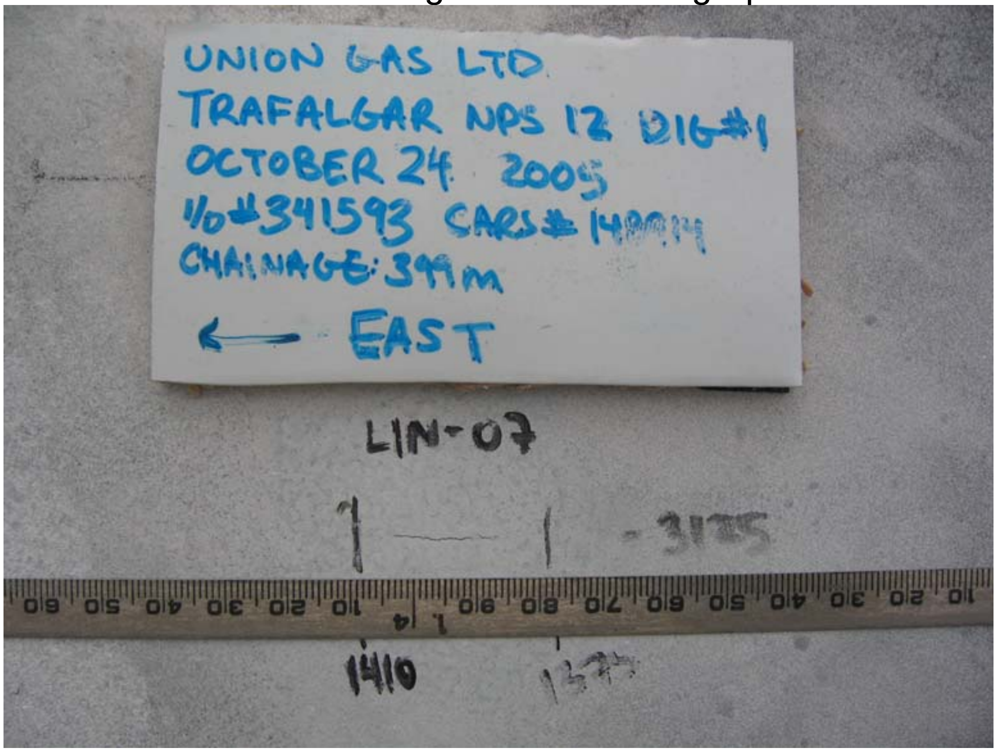
62) ARC-03

NPS 42 Trafalgar Site 1 Photographs

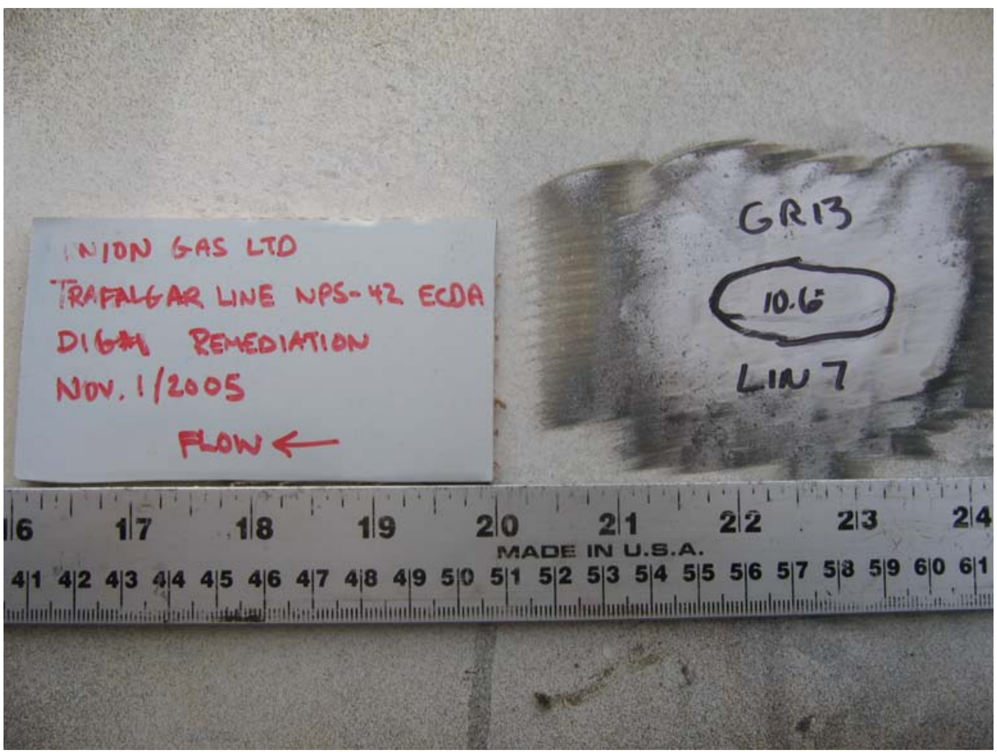
63) GR-12

64) GR-12 Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs



65) LIN-07



66) GR-13

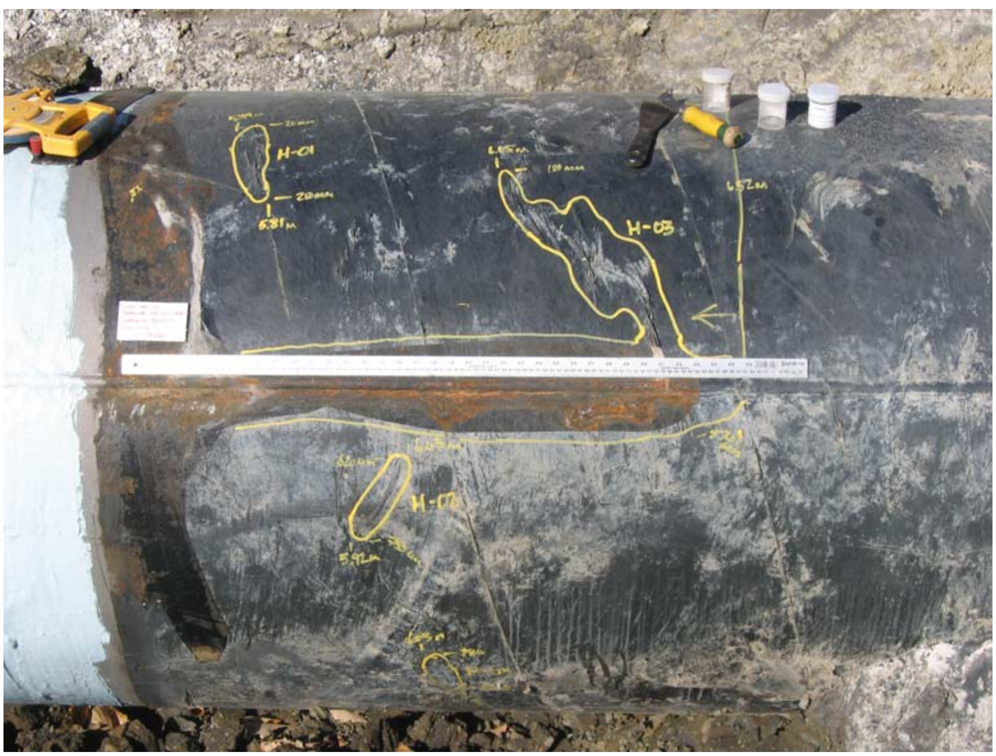
NPS 42 Trafalgar Site 1 Photographs

67) GR-13 Magnetic Particle

68) Corrosion on Longseam

NPS 42 Trafalgar Site 1 Photographs

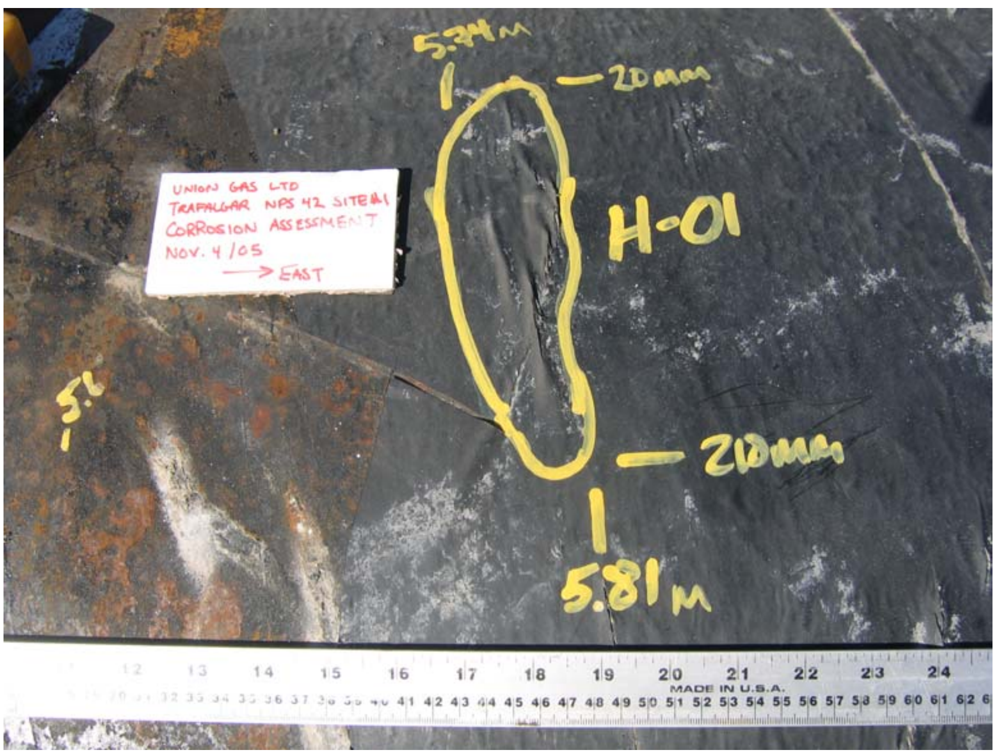
69) Corrosion Along Longseam



70) Disbondment Mapping South Side

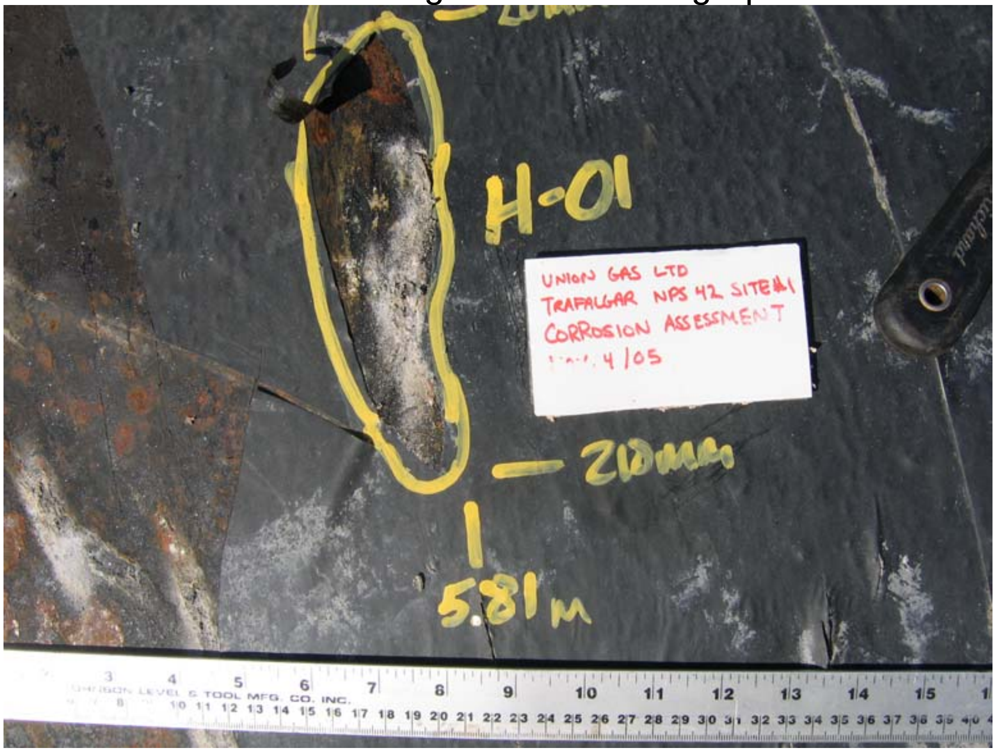
NPS 42 Trafalgar Site 1 Photographs

71) Disbondment North Side



72) H-01

NPS 42 Trafalgar Site 1 Photographs



73) H-01 Corrosion

74) H-02

NPS 42 Trafalgar Site 1 Photographs

75) H-02 Corrosion

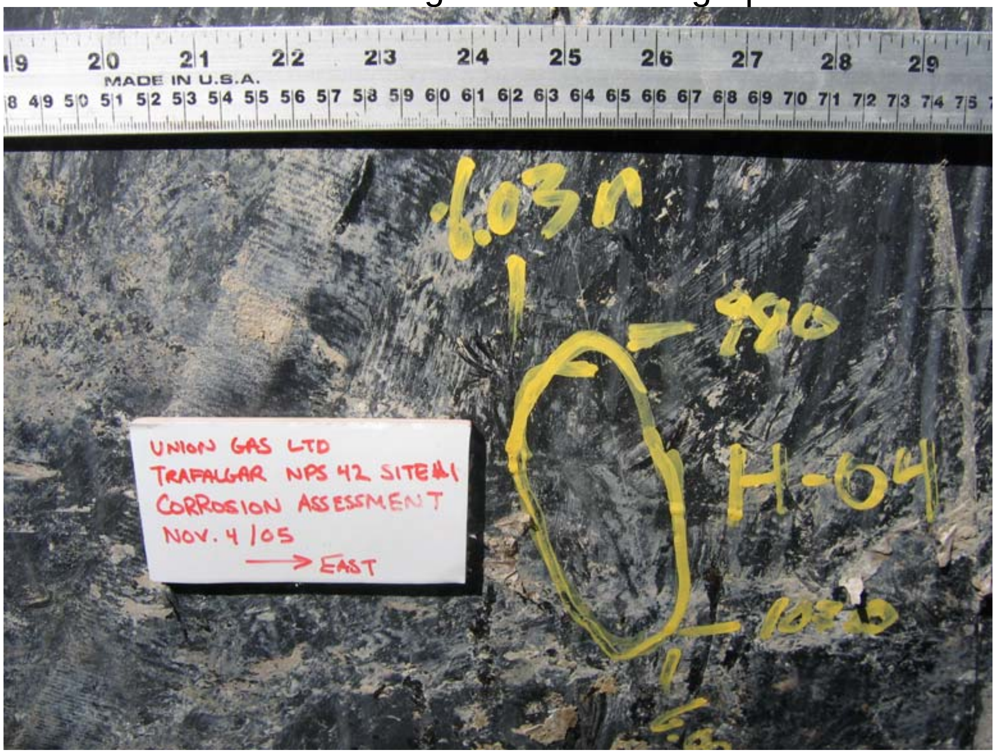
76) H-03

NPS 42 Trafalgar Site 1 Photographs

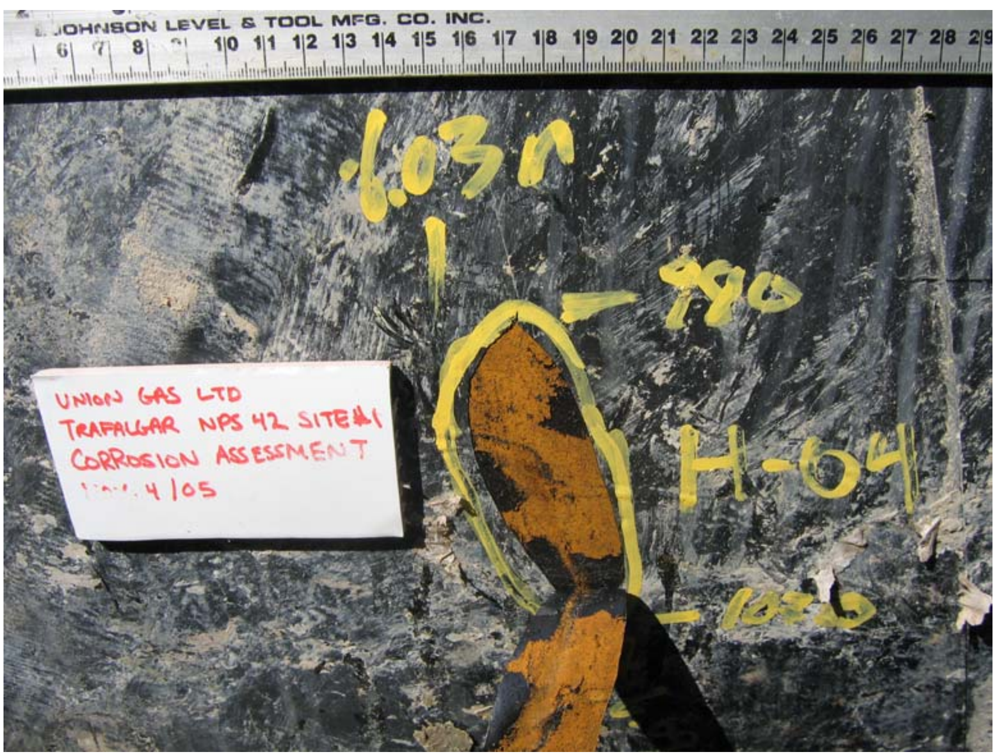
77) H-03 Corrosion and Sand

78) H-03 Corrosion Product

NPS 42 Trafalgar Site 1 Photographs



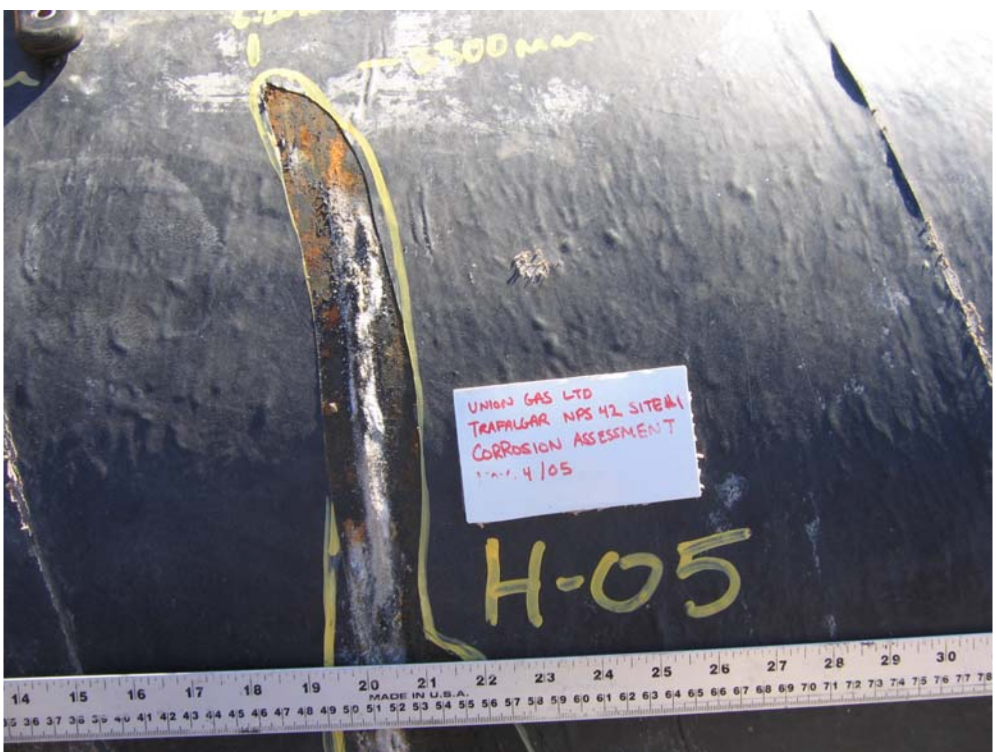
79) H-04



80) H-04 Corrosion

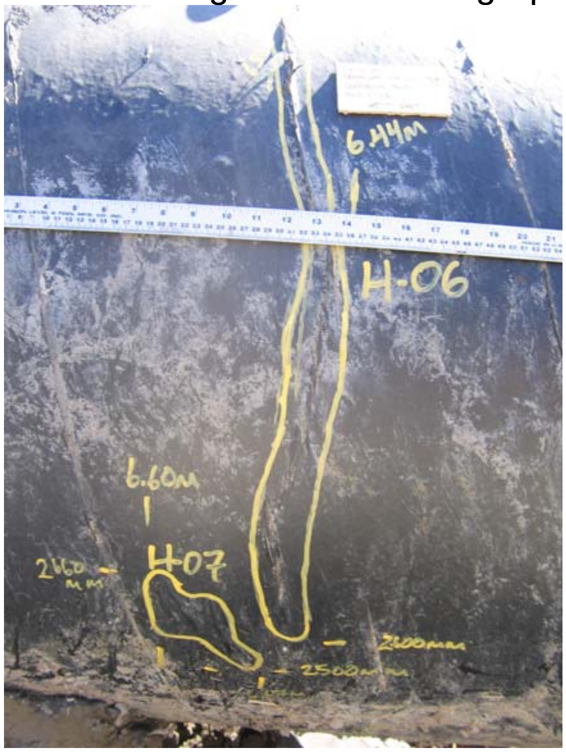
NPS 42 Trafalgar Site 1 Photographs

81) H-05

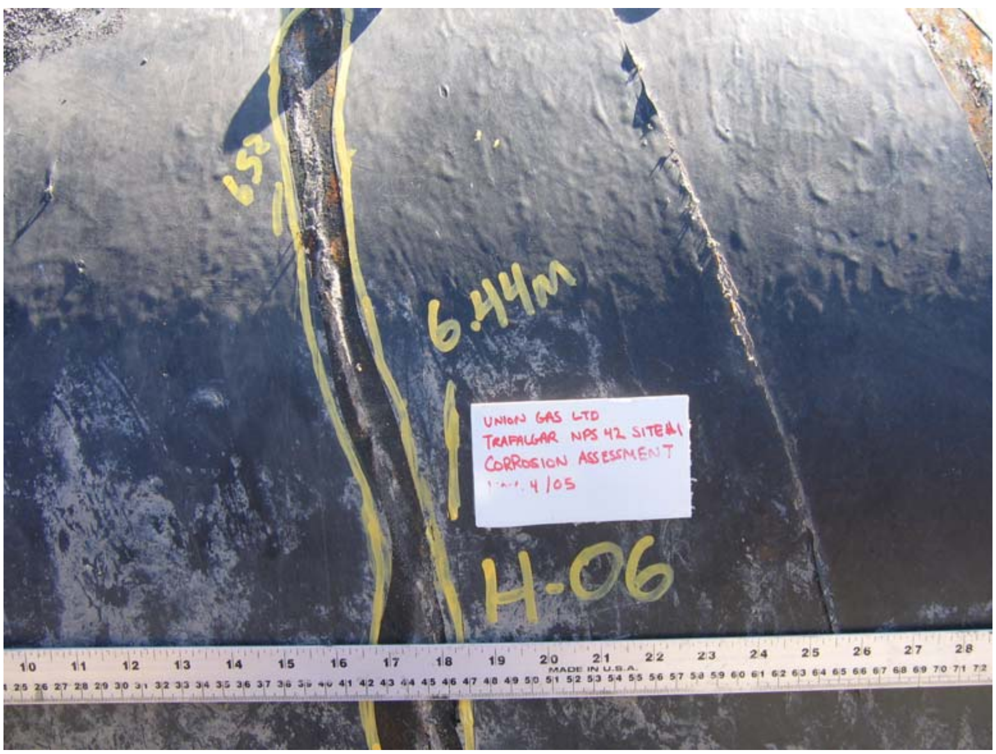


82) H-05 Corrosion and Sand

NPS 42 Trafalgar Site 1 Photographs



83) H-(06,07)



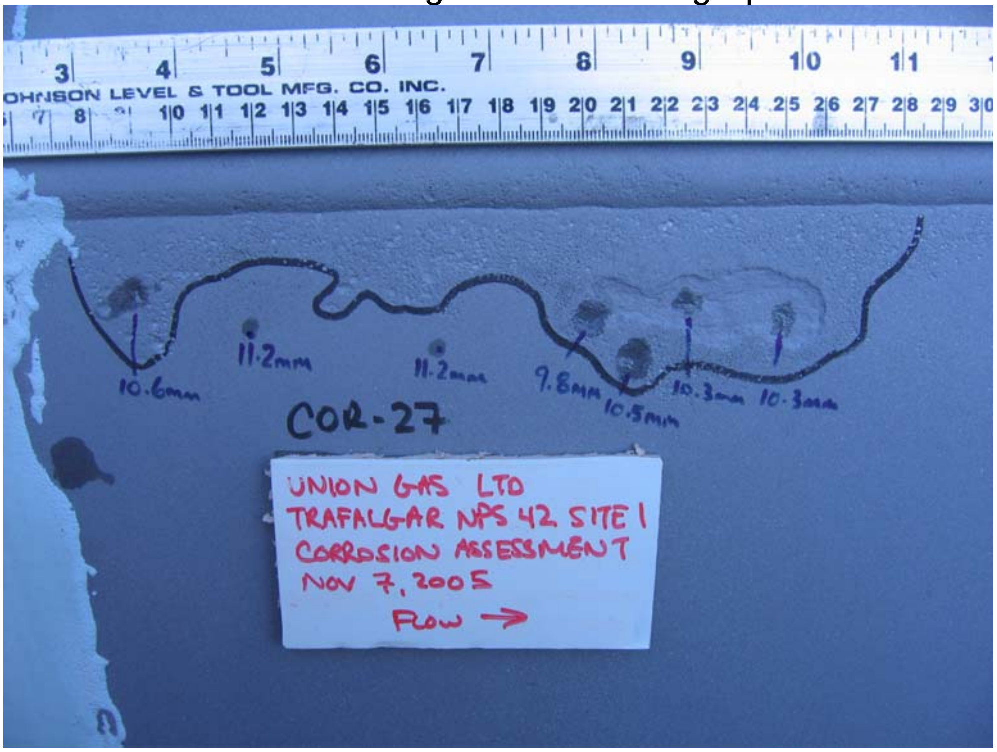
84) H-06 Corrosion and Sand

NPS 42 Trafalgar Site 1 Photographs

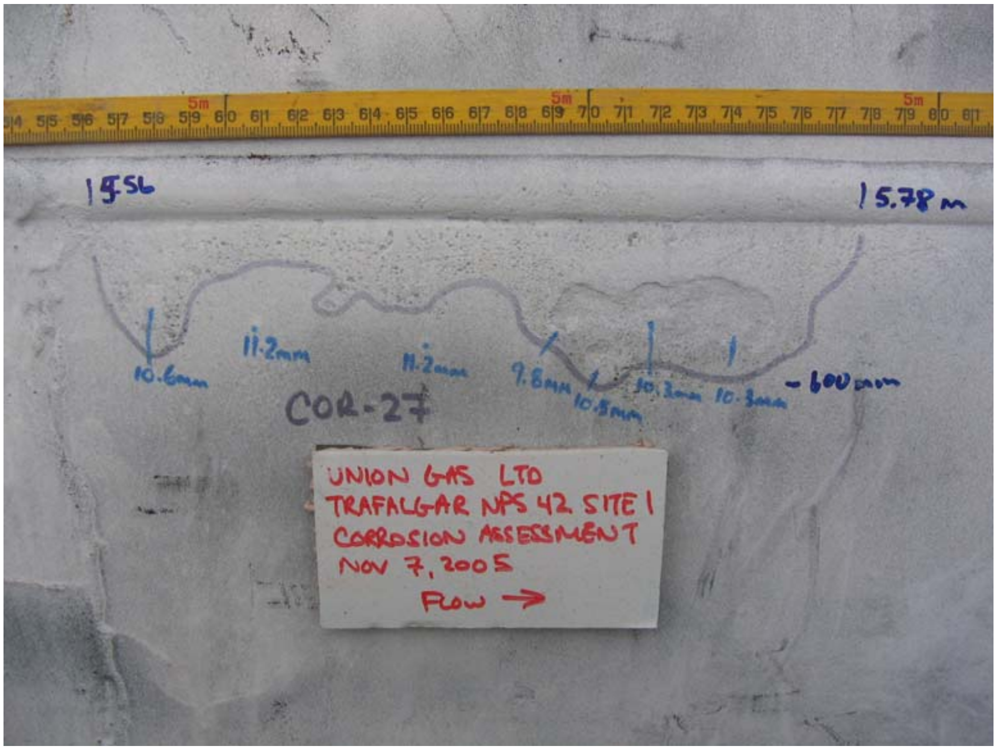
85) H-07 Corrosion

86) Longseam Corrosion

NPS 42 Trafalgar Site 1 Photographs

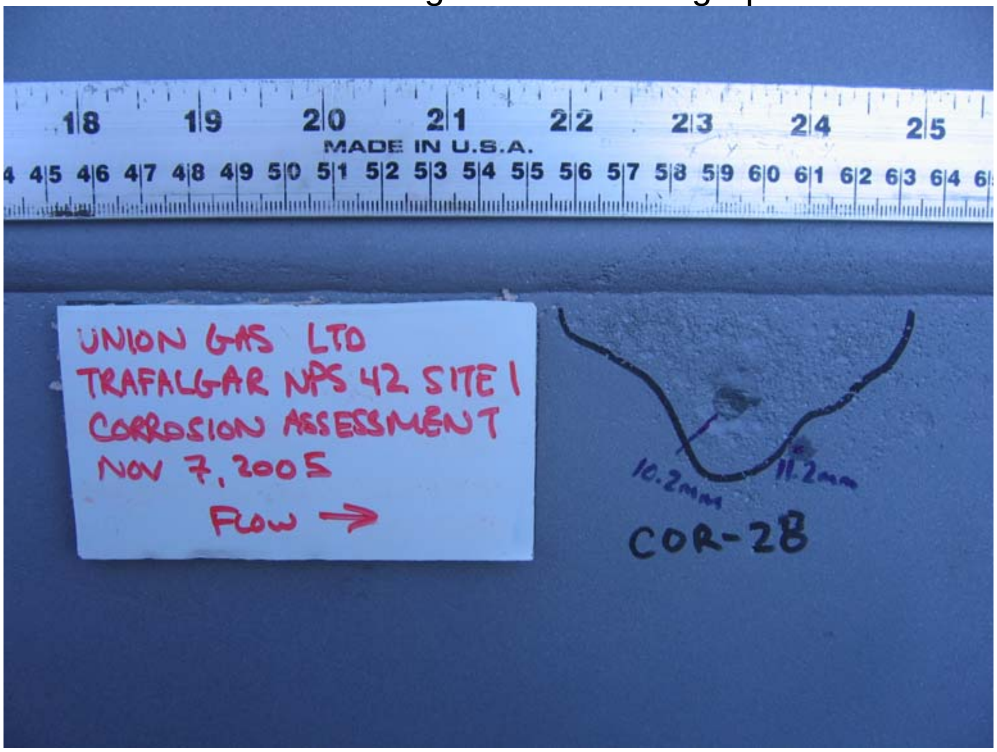


87) COR-27

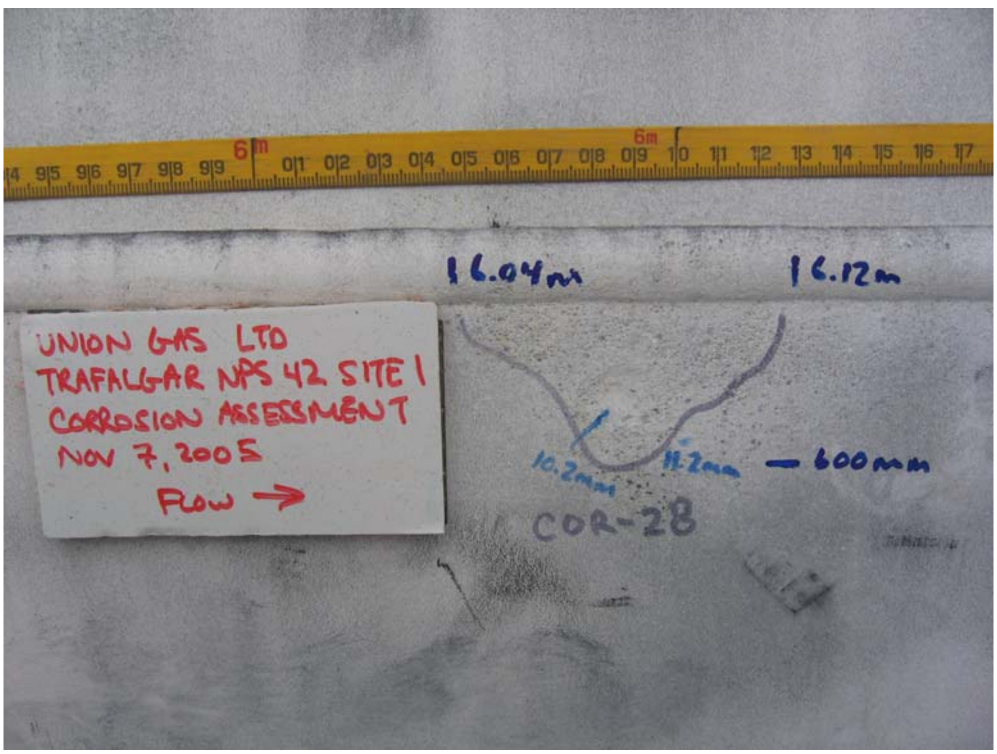


88) COR-27 Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

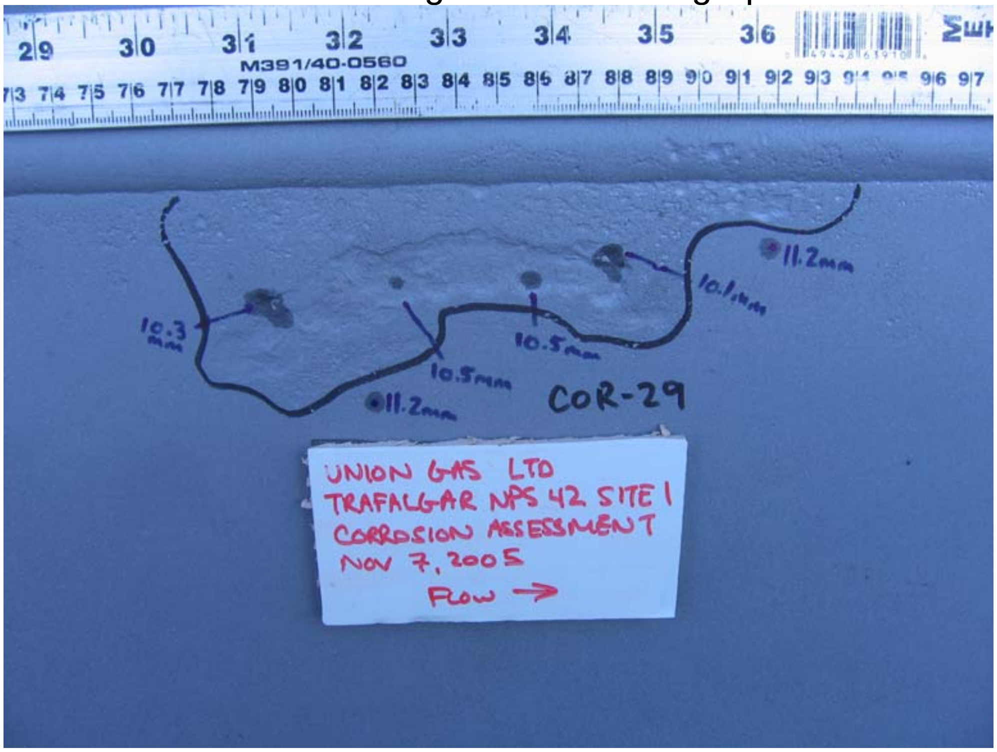


89) COR-28

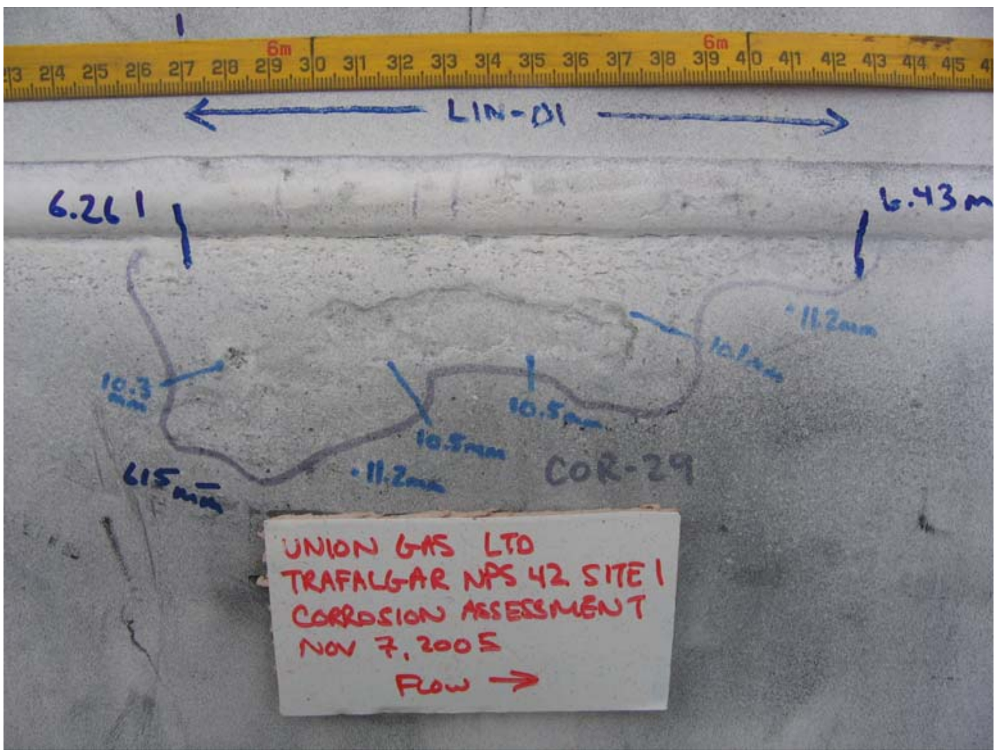


90) COR-28 Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

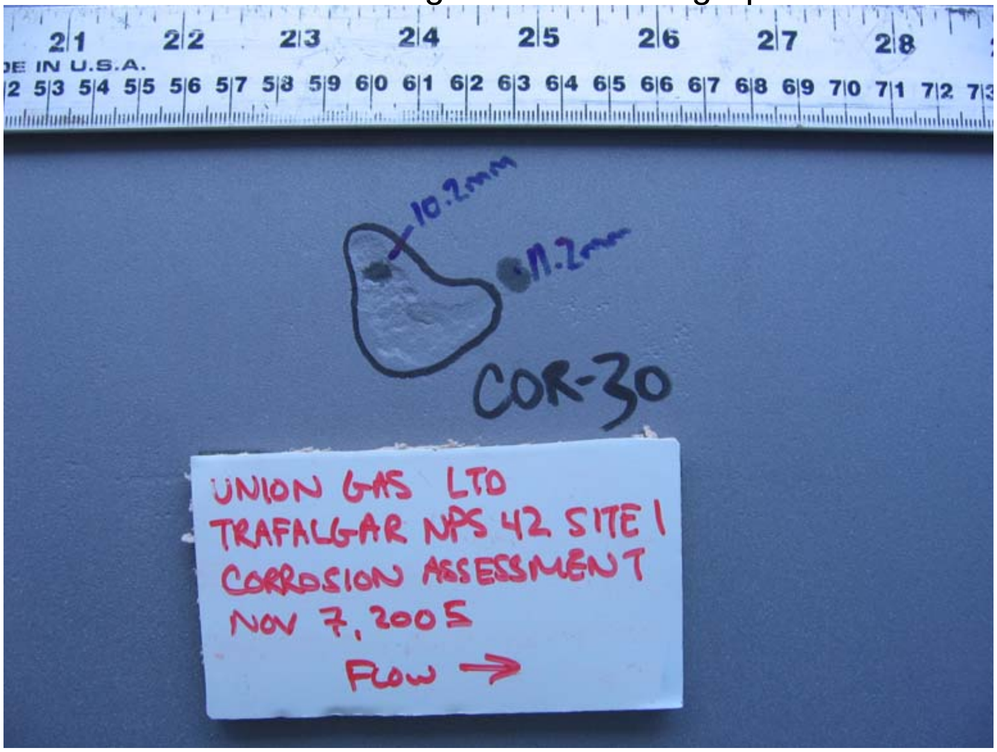


91) COR-29

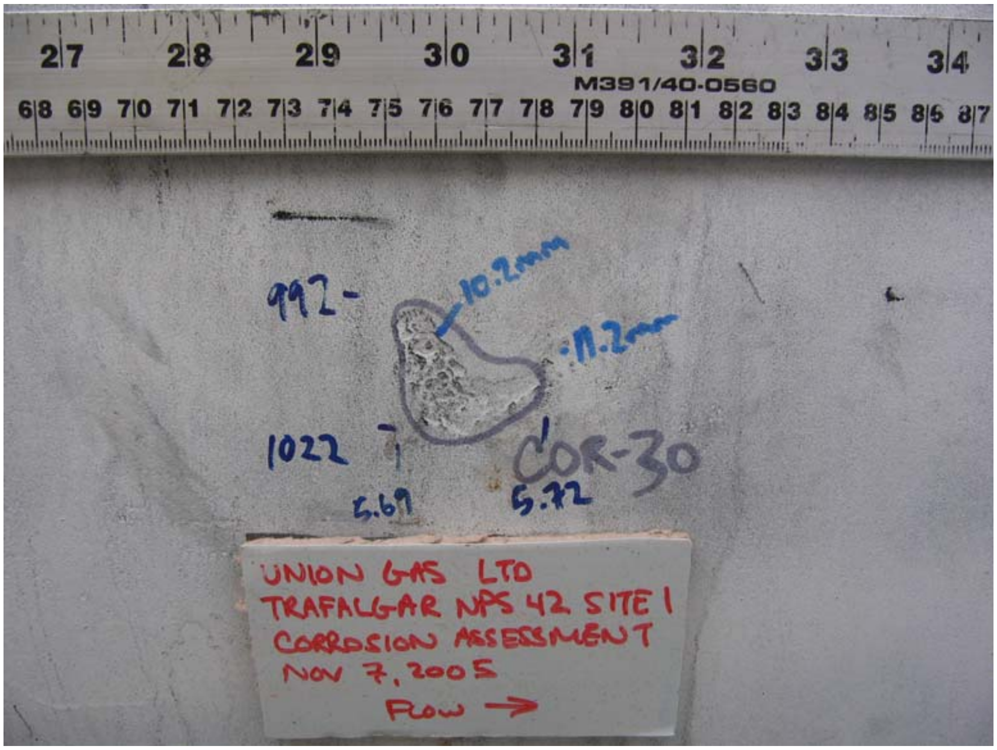


92) COR-29 Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

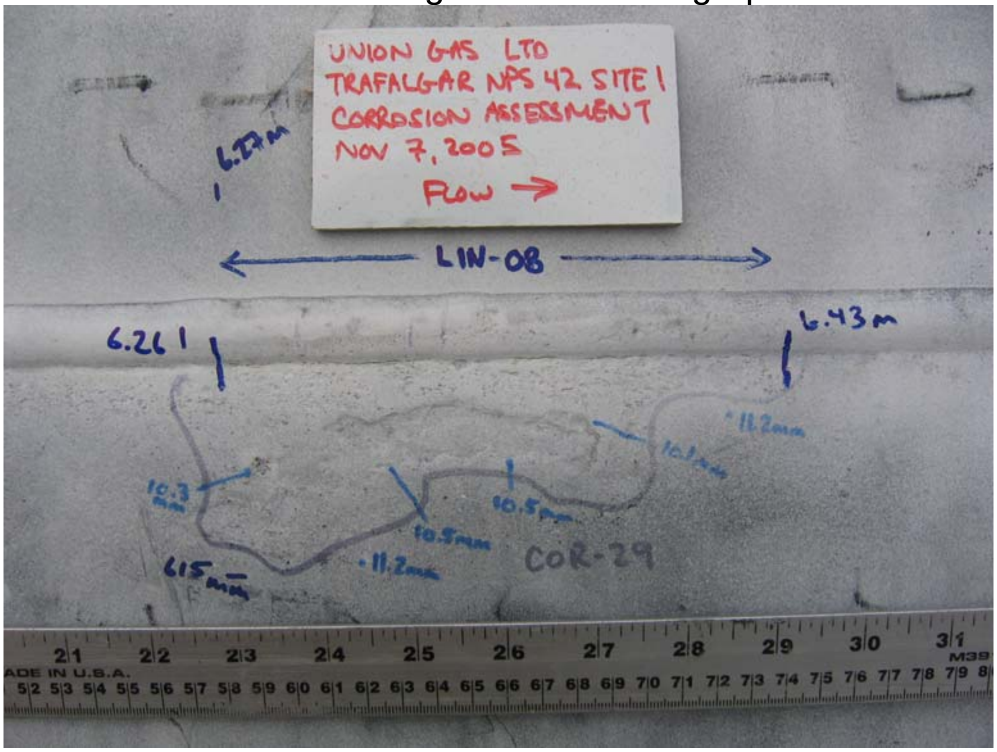


93) COR-30

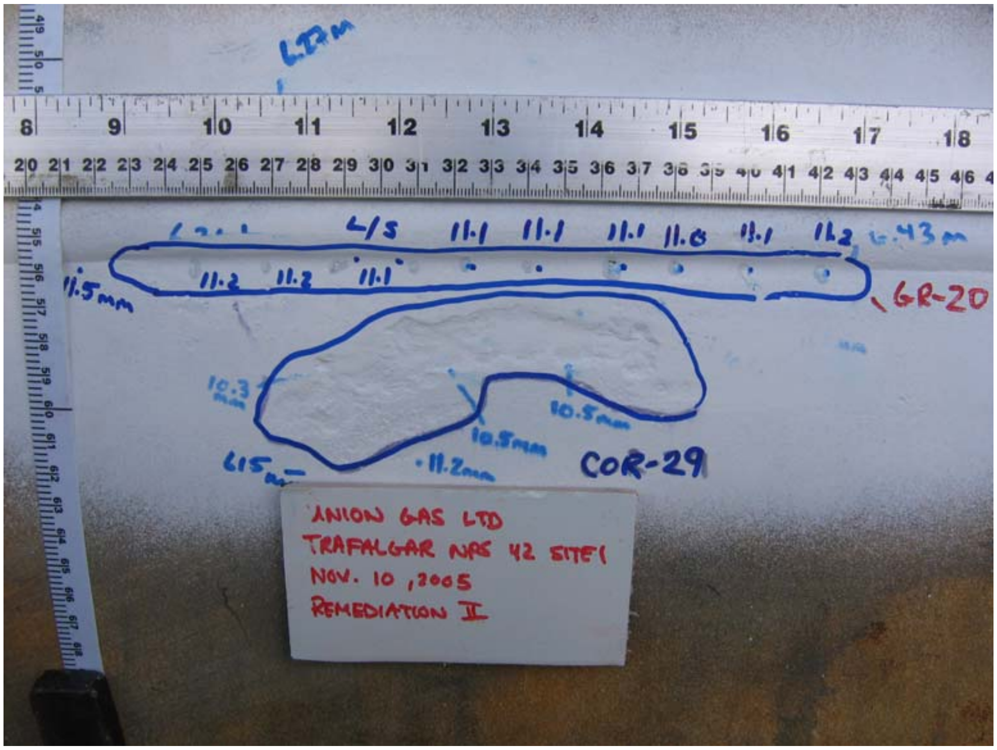


94) COR-30 Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

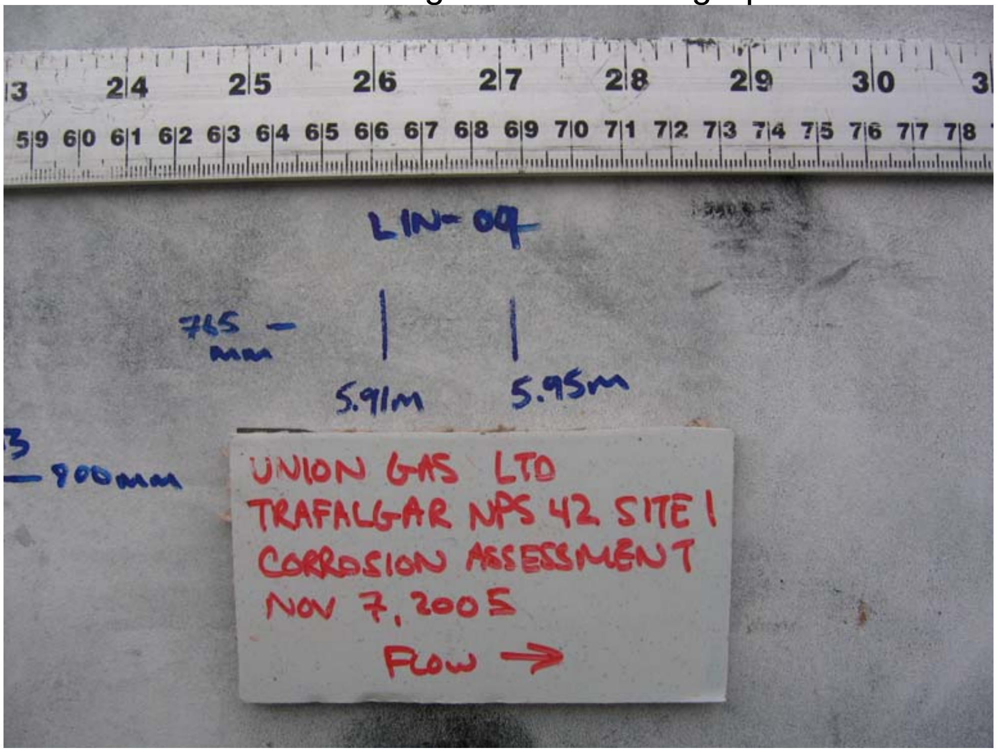


95) LIN-08

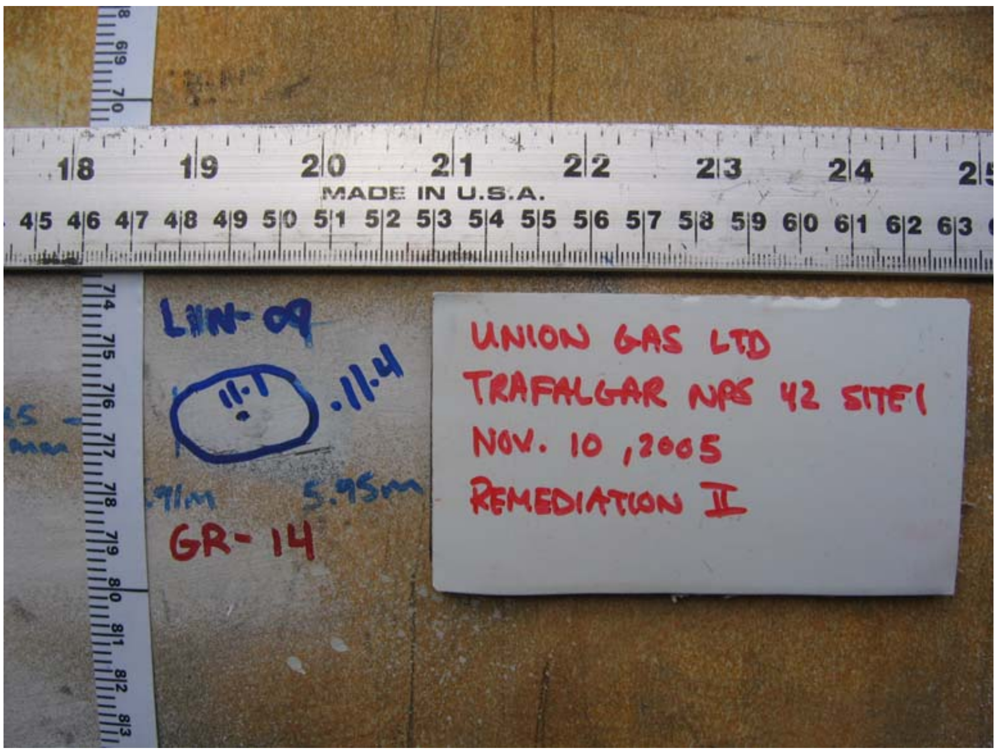


96) GR-20 (LIN-08) Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

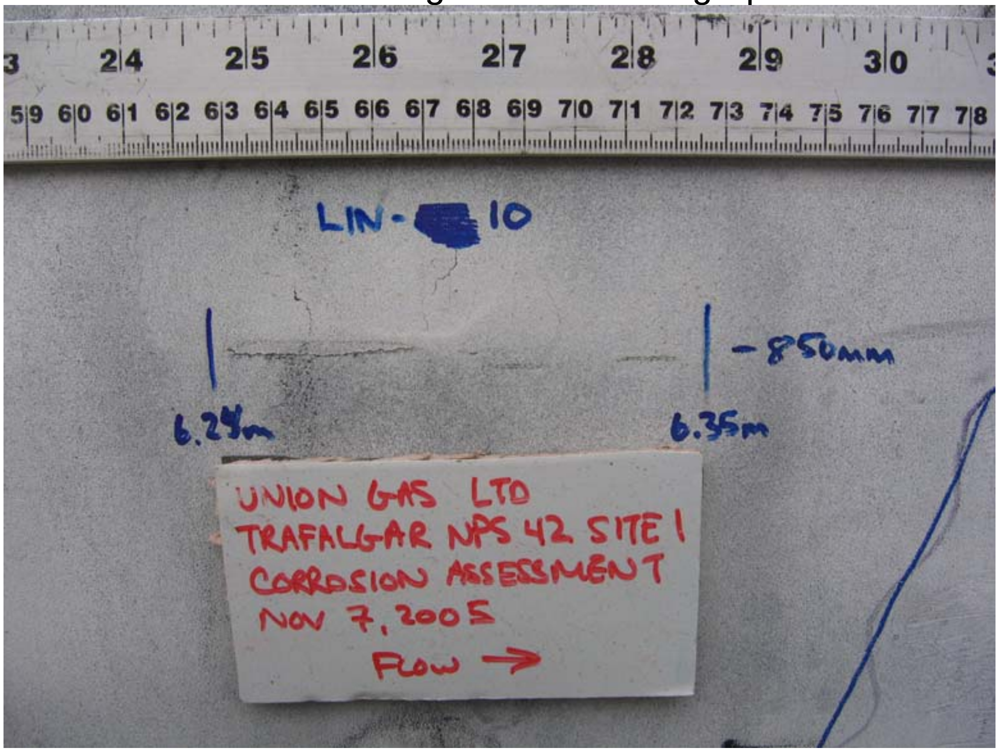


97) LIN-09

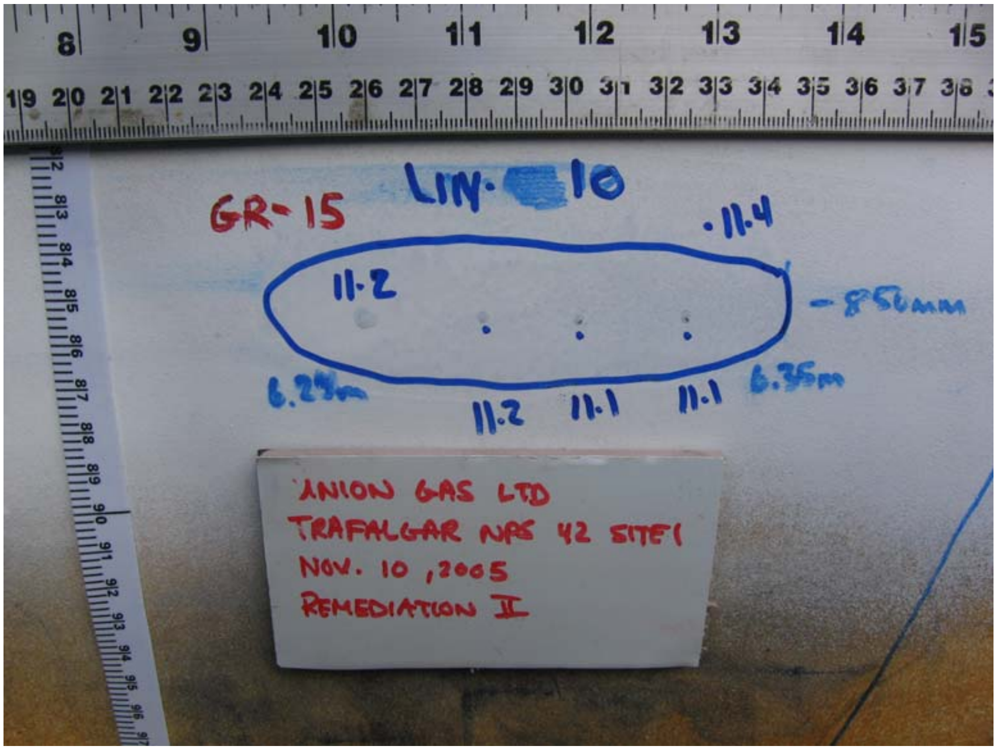


98) GR-14 (LIN-09) Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

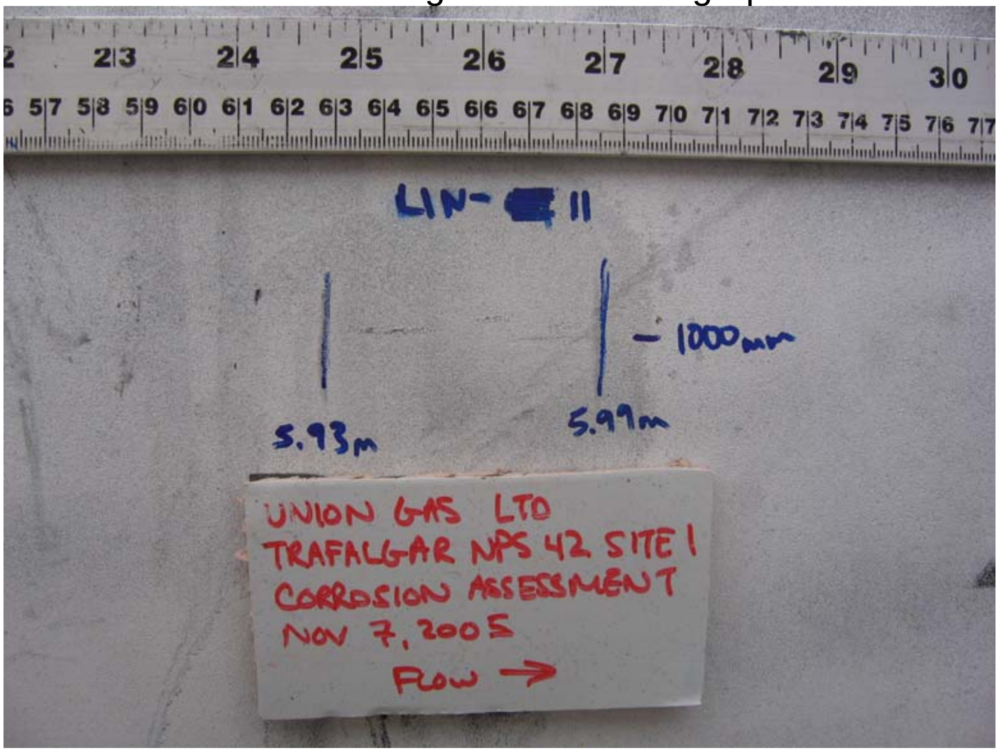


99) LIN-10

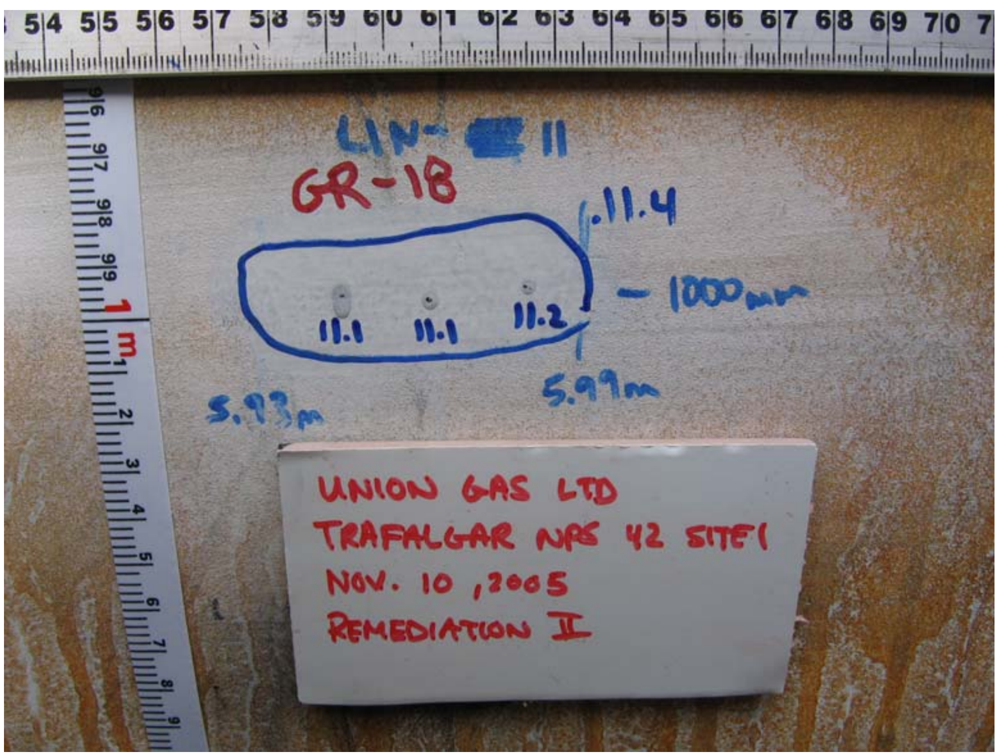


100) GR-15 (LIN-10) Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

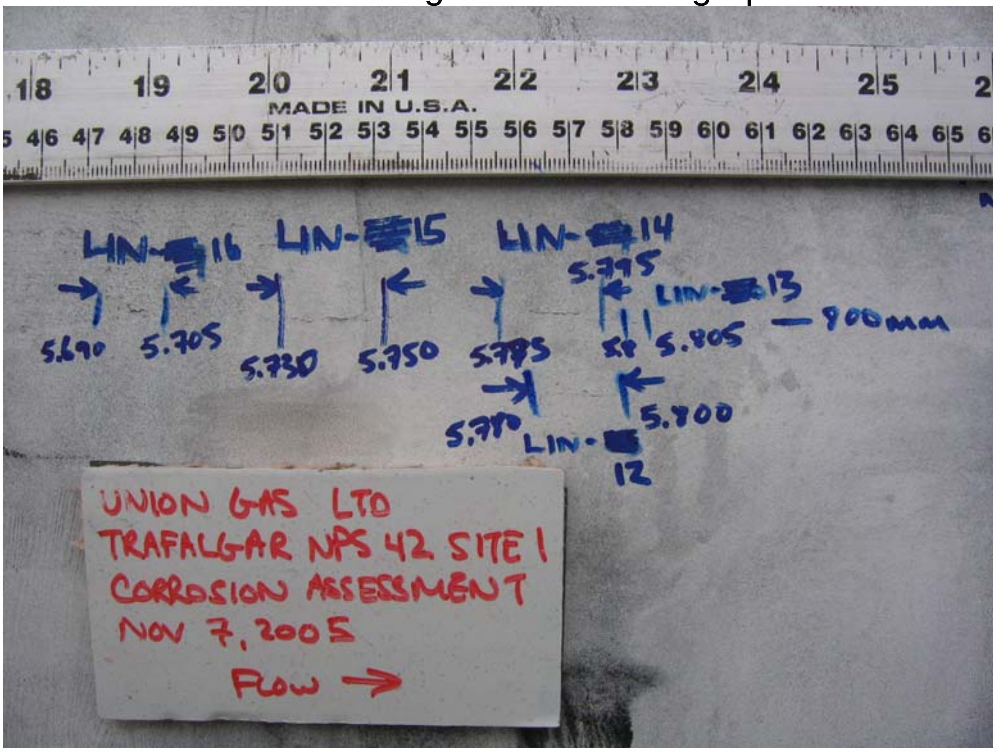


101) LIN-11

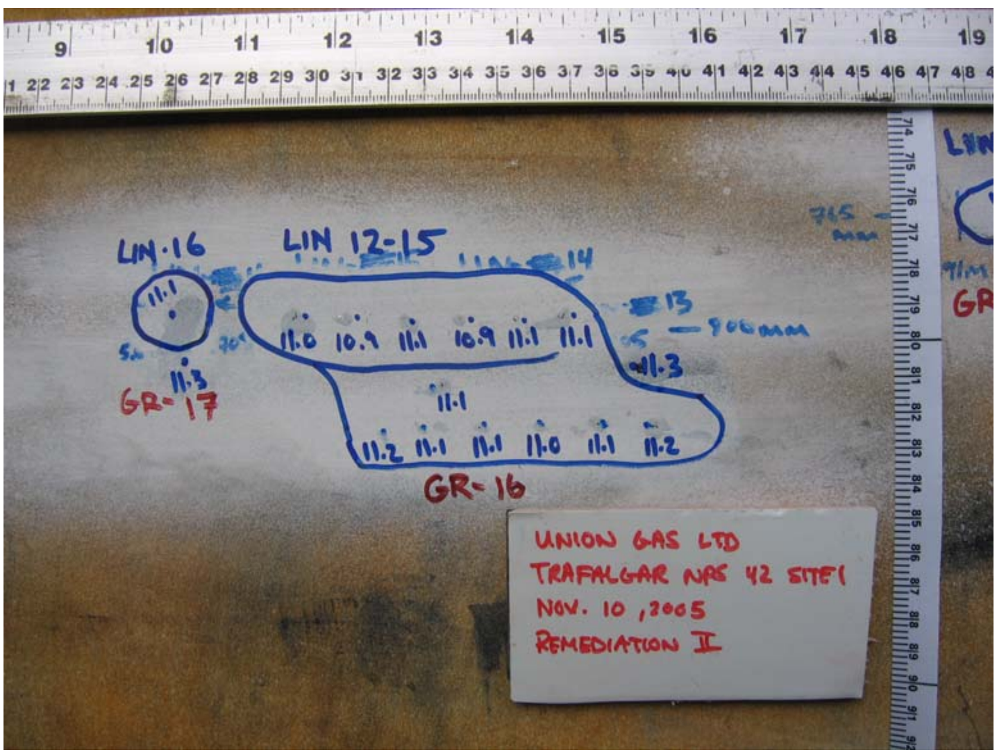


102) GR-18 (LIN-11) Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs

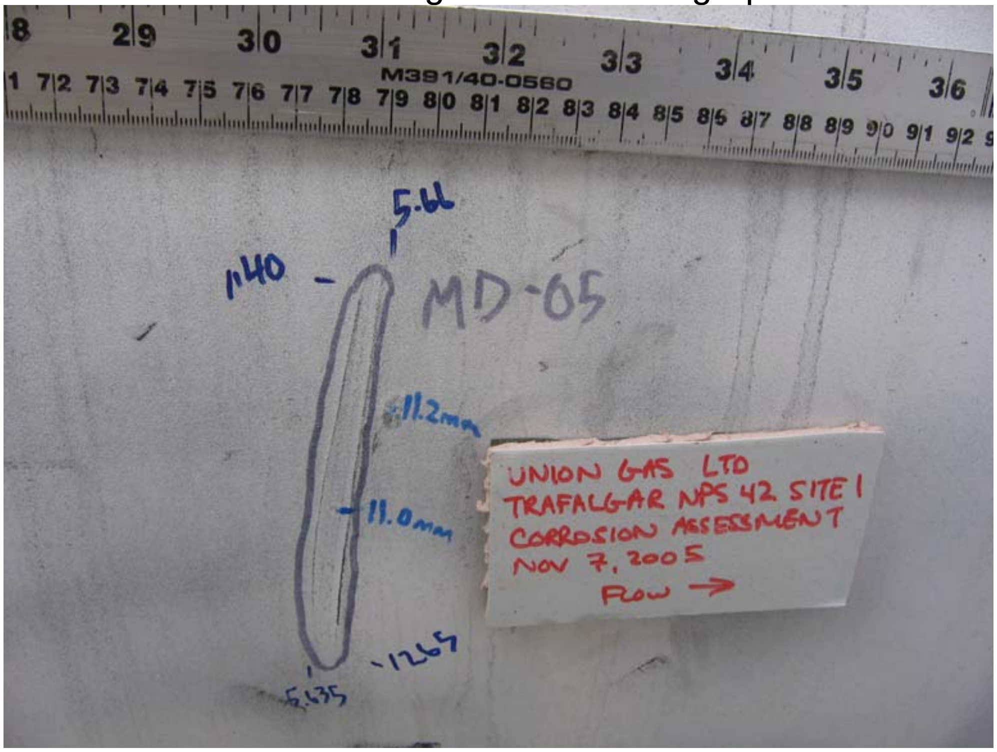


103) LIN-(12,13,14,15,16)

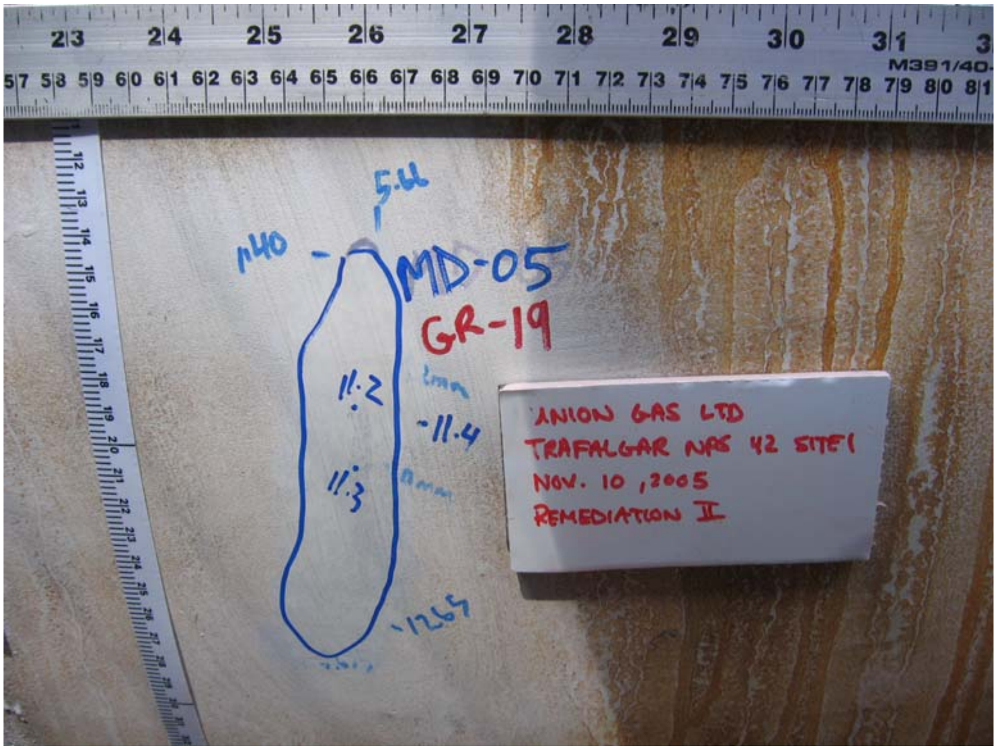


104) GR-(16,17) (LIN-16), (LIN-12,13,14,15,16) Magnetic Particle

NPS 42 Trafalgar Site 1 Photographs



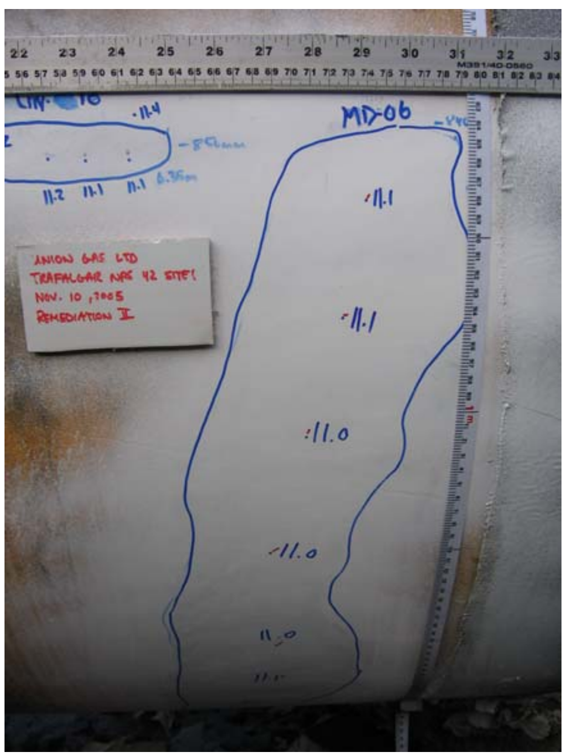
105) MD-05 Magnetic Particle



106) GR-19 (MD-05) Magnetic Particle

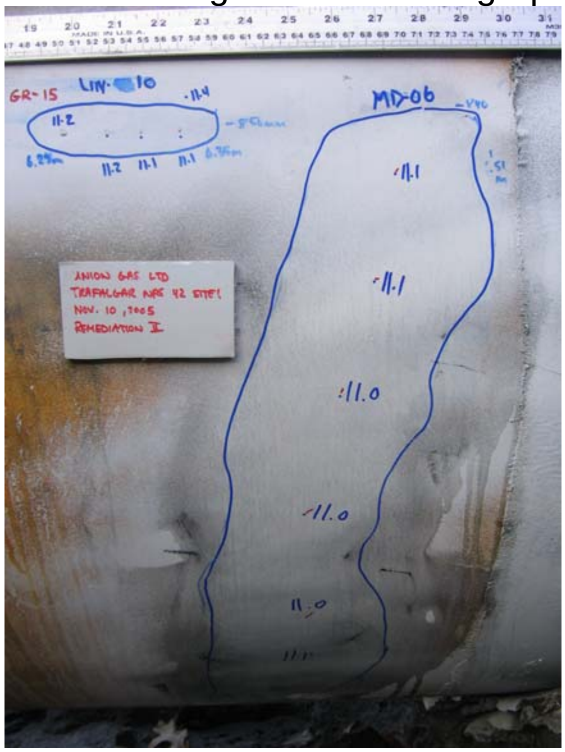
NPS 42 Trafalgar Site 1 Photographs

107) MD-06 Magnetic Particle



108) GR-21

NPS 42 Trafalgar Site 1 Photographs



109) GR-21 Magnetic Particle

Gord Phipps

From: Rob Marson
Sent: October 31, 2005 4:53 PM
To: Steve Gonneau; Pat Sarrazin; Jason Bohn
Cc: Gord Phipps; Scott Walker -Eng; Chris Falconer; Ron Grozelle; Mark Lacina
Subject: FW: Remediation - NPS-42 ECDA - Dig #1

Here is the remediation plan for dig #1 on the NPS 42. Note the pressure in the line has been reduced to less than 400 psig. The plan is to have Acuren (Canspec) work on site 1 to remove the imperfections noted below. At no time should the grind length or depth exceed the recommendation without first consulting with Pipeline Engineering.

If you have any questions please contact myself or Ron Grozelle.

Rob Marson, P.Eng.,
Senior Construction Engineer
Union Gas Limited
rmarson@uniongas.com
office: 519-436-4600, x2077
cell: 519-365-2726
pager: 519-355-2139

From: Ron Grozelle
Sent: October 31, 2005 11:33 AM
To: Rob Marson
Cc: Ken Jeans; Tom Hamilton; Mike Whitehouse; Rod Reid
Subject: Remediation - NPS-42 ECDA - Dig #1

The following is the remediation for Dig # 1

Remediation Action Report

Pipeline Name: Trafalgar Line NPS-42 ECDA
Site Location: Dig #1 Chainage 399m

Attachments: Canspec report – October 24, 2005

Psafe - 5549 kpa (804 psig)

SCC Features:

No SCC features detected. No remediation required.

Linear Indications/Laminations/Hooks:

There were seven (7) Linear Indications were found.

Remedial Action:

1. Grind/Buff linear indication following approved grind procedure specification using rubber-backed 80 – 120 grit buffing disc, to a **maximum depth of 10% (1.1mm)** actual wall thickness. The maximum grind length shall be kept to a minimum and shall not exceed **240 mm**, while ensuring a smooth transition back to the pipe surface.
2. Mag Particle the grind area of the pipe to ensure that the defect has been removed. Measure the remaining wall thickness and grind length. Examine the grind area and note if there are any other features or anomalies within the grind area.
3. Contact Pipeline Engineering – Ron Grozelle for further action.

Corrosion Features:

.re were twenty six (26) corrosion features detected less than 10% . No remediation required.

.Mechanical Damage Features:

There are four (4) scrapes/gouges. Buff the gouges following approved grind procedure specification using rubber-backed 80 – 120 grit buffing disc, to a **maximum of 10%** actual wall thickness. Grind lengths shall be kept to a minimum, while ensuring a smooth transition back to the pipe surface.

Mag Particle the grind area of the pipe to ensure that the defects have been removed. Measure the remaining wall thickness and grind length. Examine the grind area and note if there are any other features or anomalies within the grind area.

Dents:

No dents found

Arc Burns:

There were three (3) arc burns detected. Buff the arc burns following approved grind procedure specification using rubber-backed 80 – 120 grit buffing disc, to a **maximum of 10%** actual wall thickness. Grind lengths shall be kept to a minimum, while ensuring a smooth transition back to the pipe surface.

Re-inspect the buffed area using 5% Nital etch to ensure complete removal of the arch burn. Mag Particle the grind area of the pipe to ensure that the defect has been removed. Measure the remaining wall thickness and grind length. Examine the grind area and note if there are any other features or anomalies within the grind area.

Ron Grozelle, P.Eng.,
Senior Pipeline Engineer
Operations Technical Support
Pipeline Engineering
Ph: 1-519-436-5247
Cell: 1-519-365-0713
Fax: 1-519-436-5292
e-mail: rgrozelle@uniongas.com

ACUREN

Acuren Group Inc.
2190 Speers Road
Oakville, ON L6L 2X8

Phone: 905-825-8595
Fax: 905-825-8598

Materials Engineering and Testing
a Rockwood Company

Pipeline Integrity Inspection Report

NPS 42 Trafalgar Digs
Site 2

Report Prepared For:

uniongas

50 Keil Drive North
PO Box 2001
Chatham, Ontario, Canada
N7M 5M1

Inspection By:

ACUREN

ACUREN JOB No: GL 130-5-0013
PURCHASE ORDER No: 4500124214
DECEMBER 2005

NPS 42 Trafalgar Site 2 Table of Contents

CANSPEC

Summary: Trafalgar NPS 42 Dig #2

Dig ID: **AGM: NA**

Date: **October 25, 2005**

SCOPE OF WORK: Canspec scope of work for these excavations follows UGL specification emailed July 15, 2005 from Tom Hamilton and subsequent conversations there after. which involve: All information relevant to site location and GPS coordinates are provided by UGL inspectors. No soil sampling required, this is to be evaluated on a individual basis depending on our findings. All sandblasted areas are to be VT and MT examined in search of both the target defects and any other external feature as characterized by UGL procedure and Code Z662. All information to be relayed to UGL Eng for evaluation.

Dig site 2 is located in a cleared, level wooded area East of the Union Gas Bentpath station and West of Site 1. The girth weld located at the East end of the excavation was not exposed from the coating but was used for reference. Positive distance away from the girth weld was taken to the west and positive clockwise taken when facing west. The long seam was found at 1:40. A coating and corrosion assessment was not required for this inspection thus no soil samples were collected and the cathodic potential was not measured. The pipe wall thickness was measured to be 11.2mm thick.

No dents or SCC were found on the pipe.

Thirteen areas of corrosion were noted having wall loss of less than 10% the actual wall thickness and six areas were found having wall loss of up to 12%. Most of the corrosion was located next to the long seam. Five areas of mechanical damage were recorded with MD-02 and MD-03 having linear indications within the gouging. The linear indications could not be sized for depth due to their location in the gouge and their lengths.

Remediation action required the removal of five areas of mechanical damage and the linear indications found within the gouges of MD-02 and MD-03 by following the approved grinding procedure specifications. A rubber backed 120 grit buffing disc was used to remove the linear indications and mechanical damage, ensuring minimal grind lengths and a smooth transition to the adjacent surface. Magnetic particle testing was performed to ensure the removal of all defects. All defects were removed below 10% NWT. The remediation action report indicated the removal of three arc burns that were not present in the initial inspection report for this sight although dig site #1 had three arc burns.

CANSPEC

Pipeline Integrity Field Inspection Report
Trafalgar NPS 42 Dig #2
AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Basic Information

Dist from Launch (m): NA
Kilometre Post: NA
Reference Girth Weld: Exposed

Pipe Information

Line #: Trafalgar NPS 42 Dig #2
Line Diameter (mm): 1165.0
Long Seam Type: DSAW

Nominal Pipewall Thickness (mm): 11.20
Actual Pipewall Thickness (mm): 11.20

ILI Dig Information

Type of ILI Tool: NA
ILI Inspection Date: NA
Tool Vendor: NA

Reason for Excavation: Corrosion **SCC**

Location Information

1/4 sec (lot): NA
SEC (conc): NA
TWP: NA

RGE: NA
W: NA
Other (GPS): -82.2161165 Longitude 42.7164243 Latitude

AGM: NA
Distance from AGM to GW (m): NA
GW is U/S or D/S to AGM: NA

Excavation Information

Start of NDE to Reference Point (m): 0.50
End of NDE to Reference Point (m): 8.10
Depth of Cover (m): 1.20

Excavation Length (m): 18.80
Excavation Width (m): 6.80

GW Number Exposed*	Joint Length (m)	Type of Joint Exposure	Longseam Orientation (Clock Position)	Method of detecting the LS weld
GW	8.1	Partial	1:40	Visual

*Only to be filled in for welds that are fully exposed.

Technician 1 James Allen
Technician 2 Jason Bohn

On File
Signature

On File
Signature

Pipe Pressure at Time of Inspection (PSI) ______
Pipe Temperature (C): ______

Method of MPI Color Contrast - Water Based

CANSPEC

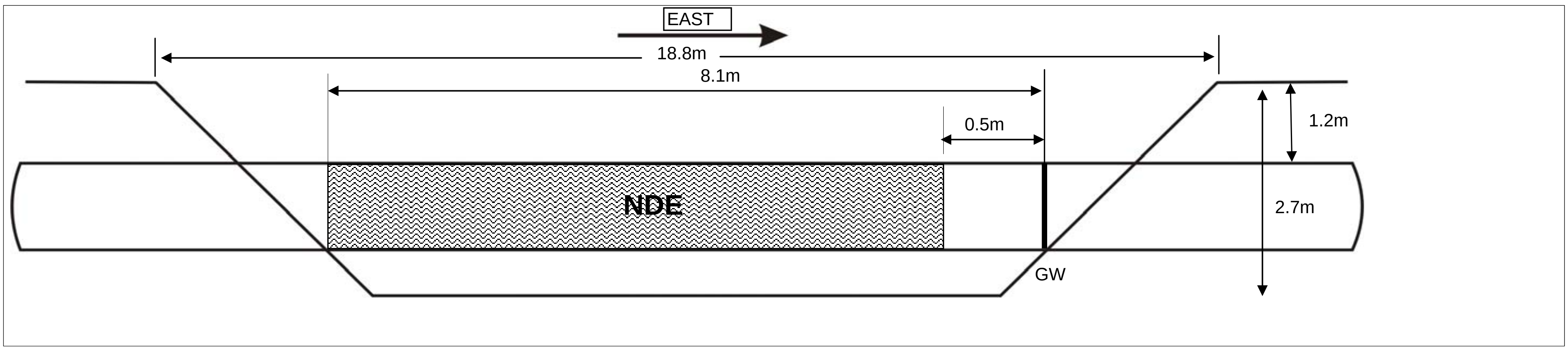
Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2
AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Sketch of Excavation

ELEVATION VIEW



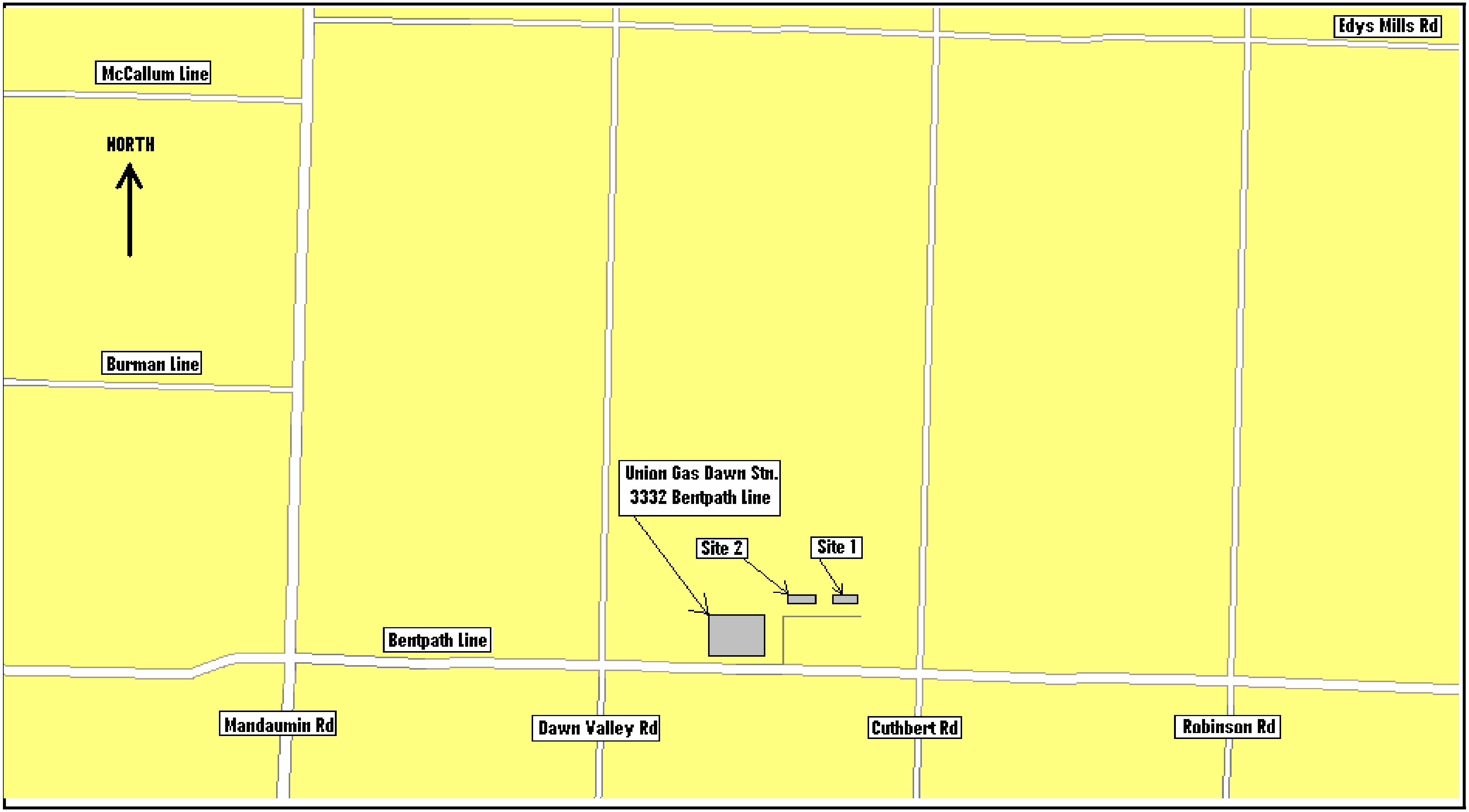
All measurements must be made from reference.

Does section have sag?	☐ Yes ☑ No **If Yes,**	Location from reference (m):	------	Reference Point:	GW
Does section have an overbend?	☐ Yes ☑ No **If Yes,**	Location from reference: (m)	------	Excavation Width (m)	6.80
Number of full joints in excavation:		Excavation Type (**F**ull/**B**ell)		Depth of Ditch (m)	2.70
Start of exposed pipe (360°) to reference (m)		End of exposed pipe (360°) to reference (m)	8.100	Depth of Cover (m)	1.20
Start of NDE to reference point (m)	0.50	End of NDE to reference point (m)	8.100	Ditch Length (m)	18.80
Spiral Weld? ☐ Yes ☑ No	**If no,**	Longseam Orientation (Clock Position): West of GW	GW 1 : 40 o'clock	Dist Long seam from TDC (mm)	510

Site Diagram Trafalgar NPS 42 Dig #2

Dig ID: Trafalgar NPS 42 Dig #2

Date: October 25, 2005



CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2

AGM: NA

Client: Union Gas

Date: October 25, 2005

Girth Weld: Chainage 68m

Soil and Landscape Information

Land Use Cultivated

Site Position Level

Topography Level

Parent Material Till (Moraine)

Texture Sandy Clay

Coarse Fragments Estimated % By Volume: **10%**

- ☐ Boulders (> 60 cm)
- ☑ Small Stones (2.5 cm <= X<10)
- ☐ Large Stones (10 cm <= X<60)
- ☑ Gravel (<2.5 cm)

Drainage Poor

Gleying Strongly Gleyed (Dark Grey)

Mottling

Abundance	Common
Size	Medium
Contrast	Distinct

Visible Salts
(Check All That Apply)

- ☐ Surface Salt Crusts (White and Powdery)
- ☐ White/Grey Salts at Pipe Depth That Don't React With Acid
- ☐ Gypsum (Clear to Brown) Salt Crystals At Pipe Depth-Don't React With Acid
- ☐ Other (Explain in Comments)

Soil and Environmental Comments

Gleying and mottling is present in the soil pile.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2

AGM: NA

Client: Union Gas

Date: October 25, 2005

Girth Weld: Chainage 68m

Coating Condition

Pipe Coating Type Polyethylene Tape

Weld Coating Type Polyethylene Tape

Cathodic Potential (mV)
US/DS ____________

Pipe Coating Condition Poor

Weld Coating Condition Poor

Coating Comments

Coating was removed prior to investigation.

Corrosion Deposits

Corrosion Present ☑ Yes ☐ No

Colour		Texture		Magnetic Reaction		Carbonate Reaction (10% HCl Reaction)	
White	☐	Film	☐	Strong Magnetic Reaction	☐	Bubbles Strongly	☐
Brown	☐	Pasty	☐	Weak Magnetic Reaction	☐	Bubbles Weakly	☐
Black	☐	Scaly	☐	Does Not React	☐	Does not Bubble	☐
Green	☐	Powdery	☐			Rotten Egg Smell	☐
Olive/ Beige	☐	Metallic	☐			Turns Yellowish	☐
Orange	☐	Waxy	☐			Turns Clear	☐
Blue	☐						
Grey	☐						
Red	☐						
Clear	☐						

Samples Collected

Sample Number	Associated Feature / Location

Corrosion Product Comments

Corrosion examination was not required as part of this inspection.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2
AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Sampling and Analysis

SOIL

Sample No.	Location	pH	ORP	10% HCl Reaction

ELECTROLYTE

Sample No.	Sample Taken (Y/N)	Location	pH
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

GROUNDWATER

Sample No.	Location	pH	ORP

Sampling and Analysis Comments

No groundwater was present in the excavation. Soil samples were not required as part of this inspection. Coating was removed and the pipe surface was sandblasted prior to inspection.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2
AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Corrosion Assessment

RSTRENG Completed by NA **Assessment Method** Visual, UT

Corrosion Feature Number	Type of Corrosion	Relative to Girth Weld Start of Cluster (mm)	Relative to Girth Weld End of Cluster (mm)	Total Length of Cluster (mm)	Effective RSTRENG Start Length (mm)	Effective RSTRENG Cluster Length (mm)	Circ Start of Cluster (mm)	Circ End of Cluster (mm)	Circ Width of Cluster (mm)	O'Clock From	O'Clock To	Lowest Actual Remaining Wall Thickness (mm)	Max Depth (mm)	Max Depth (%)	RSTRENG Results (RPR) (Case 1: Effective Area)	RSTRENG Results (RPR) (Case 2 0.85 DL)	On or Near Weld (Y/N) *	Rubbing Submitted (Y/N)	Reason for Repair	Sleeved (Y/N)	Figure Number
COR-01	External	1200	1220	20			885	925	40	2 : 54	3 : 02	10.30	0.90	8%			N	N	Repair not Required	N	6
COR-02	External	1060	1300	240			1050	1085	35	3 : 27	3 : 33	10.00	1.20	11%			N	N	Repair not Required	N	7
COR-03	External	1100	1210	110			1290	1350	60	4 : 14	4 : 26	10.40	0.80	7%			N	N	Repair not Required	N	8
COR-04	External	2150	2205	55			530	545	15	1 : 44	1 : 47	10.20	1.00	9%			Y	N	Repair not Required	N	9
COR-05	External	2300	2500	200			1050	1350	300	3 : 27	4 : 26	9.90	1.30	12%			N	N	Repair not Required	N	10
COR-06	External	2735	2870	135			525	575	50	1 : 43	1 : 53	10.30	0.90	8%			Y	N	Repair not Required	N	11
COR-07	External	2750	3100	350			1060	1350	290	3 : 29	4 : 26	9.90	1.30	12%			N	N	Repair not Required	N	12
COR-08	External	3020	3125	105			525	565	40	1 : 43	1 : 51	10.60	0.60	5%			Y	N	Repair not Required	N	13
COR-09	External	3030	3040	10			1105	1115	10	3 : 37	3 : 39	10.00	1.20	11%			N	N	Repair not Required	N	14
COR-10	External	3060	3070	10			1095	1105	10	3 : 35	3 : 37	9.90	1.30	12%			N	N	Repair not Required	N	14
COR-11	External	4810	5205	395			525	540	15	1 : 43	1 : 46	10.30	0.90	8%			Y	N	Repair not Required	N	15
COR-12	External	6825	6960	135			525	550	25	1 : 43	1 : 48	10.40	0.80	7%			Y	N	Repair not Required	N	16
COR-13	External	7200	7560	360			875	950	75	2 : 52	3 : 07	10.40	0.80	7%			N	N	Repair not Required	N	17
COR-14	External	7580	7760	180			525	555	30	1 : 43	1 : 49	10.30	0.90	8%			Y	N	Repair not Required	N	18
COR-15	External	7835	7960	125			530	550	20	1 : 44	1 : 48	10.50	0.70	6%			Y	N	Repair not Required	N	19
COR-16	External	6890	6640	250			2500	2360	140	8 : 12	7 : 44	10.70	0.50	4%			N	N	Repair not Required	N	20
COR-17	External	7825	7835	10			2475	2495	20	8 : 07	8 : 11	10.60	0.60	5%			N	N	Repair not Required	N	21
COR-18	External	7700	7980	280			2670	2770	100	8 : 45	9 : 05	10.60	0.60	5%			N	N	Repair not Required	N	22
COR-19	External	4750	4760	10			915	913	2	3 : 00	2 : 60	10.10	1.10	10%			N	N	Repair not Required	N	23

* **ON** - On Weld, **NEAR** - From toe of weld to 10 mm

Corrosion Comments

CANSPEC

Pipeline Integrity Field Inspection Report
Trafalgar NPS 42 Dig #2
AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

COATING INSPECTION

AREAS OF DISBONDMENT (Includes Wrinkling) AND MAJOR HOLIDAYS

Feature Number	Start of Feature Axially (mm)	End of Feature Axially (mm)	Axial Length (mm)	Top Dead Centre to Start of Feature (Circ.) (mm)	Top Dead Centre to End of Feature (Circ.) (mm)	Circumferential Width (mm)	Clock Position (to start of feature)	Reason for Disbond (1)	pH @pipe surface

Comments

Coating assessment was not required as part of this inspection.

Pipeline Integrity Field Inspection Report
Trafalgar NPS 42 Dig #2
AGM: NA

Corrosion Map of Feature H1 & H2

Client: Union Gas
Date: 25-Oct-05

Each Square =	0.2314286	m
Coating Thickness =	#DIV/0!	mils

Coating thickness gaug	X	
Pit Depth Gauge		

Direction of Flow

Map X axis represents longitudinal distance in mm from referenc
Map Y axis represents distance measured from TDC in mm

Symbols are B for bare, D for disbonded. Numbers are coating thickness in mils.
Black numbers are pipe coating thickness surface pH numbers in blue

	0.0	0.2	0.5	0.7	0.9	1.2	1.4	1.6	1.9	2.1	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	####	CLOCK POSITION
10																																				12:00
40																																				
70																																				
100																																				
130																																				
160																																				
190																																				
220																																				
250																																				
280																																				3:00
310																																				
340																																				
370																																				
400																																				
430																																				
460																																				
490																																				
520																																				6:00
550																																				
580																																				
610																																				
640																																				
670																																				
700																																				
730																																				
760																																				9:00
790																																				
820																																				
850																																				
880																																				
910																																				
940																																				
970																																				
1000																																				
1030																																				12:00

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2
AGM: NA

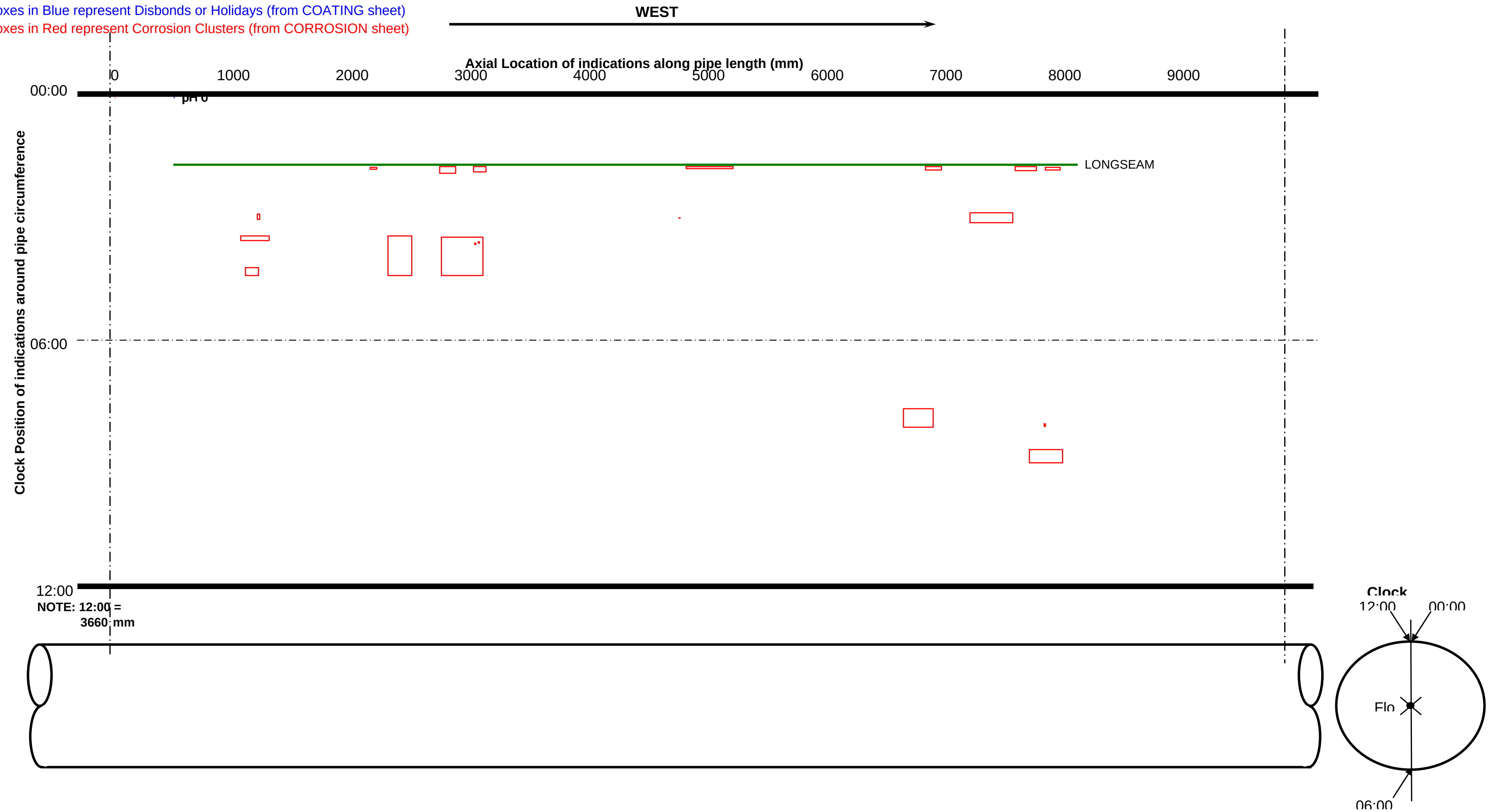
Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Coating and Corrosion Diagram

NDT Inspector **NDT Company** Canspec Group Inc.

Pipe Rollout

Boxes in Blue represent Disbonds or Holidays (from COATING sheet)
Boxes in Red represent Corrosion Clusters (from CORROSION sheet)



CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2
AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Grind Assessment

Grind Feature Number	Corresponding Features Within Grind Area	Measured Wall Thickness Before Grinding (mm)	Measured Wall Thickness After Grinding (mm)	Measured Grind Length after Grinding (mm)	Type of Repair	Client Contacted (Y/N)
GR-01	MD-01	11.10	10.80	20	Removed	N
GR-02	MD-02	11.10	10.70	20	Removed	N
GR-03	MD-03	11.10	10.00	20	Removed	N
GR-04	MD-04	11.10	10.90	140	Removed	N
GR-05	MD-05	11.10	10.80	30	Removed	N

Grind Area Comments

Linear indications present in the gouges of MD-02 & MD-03 were removed with the corresponding grind features.

	Wall Thickness @ Reference GW			
	Upstream (mm)		Downstream (mm)	
12:00	11.10		11.20	
3:00	11.20		11.20	
6:00	11.20		11.20	
9:00	11.10		11.20	

	Wall Thickness @ West of GW			
	Upstream (mm)		Downstream (mm)	
12:00				
3:00				
6:00				
9:00				

Mechanical Damage and Arc Burn Assessment

Damage Feature Number	Relative Distance to U/S GW to feature (mm)	Orientation of Feature (Clock Position)	Type of Damage	Length (mm)	Max Depth (mm)	Max Depth (%)	Figure Number
MD-01	1655	10:25-10:34	Scrape /Gouge	25	0.20	2%	24
MD-02	2775	9:25-9:44	Scrape /Gouge	5	0.20	2%	27
MD-03	2740	9:30-9:54	Scrape /Gouge	10	0.20	2%	27
MD-04	1400	8:28-8:31	Scrape /Gouge	130	0.20	2%	32
MD-05	5920	3:26-3:35	Scrape /Gouge	50	0.60	5%	34

Mechanical Damage and Arc Burn Comments

MD-02 and MD-03 were found to have linear indications within the gouging.

	Wall Thickness @			
	Upstream (mm)		Downstream (mm)	
12:00				
3:00				
6:00				
9:00				

	Wall Thickness @			
	Upstream (mm)		Downstream (mm)	
12:00				
3:00				
6:00				
9:00				

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2

AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Linear Indication Assessment

NDT Inspector James Allen **NDT Company** Acuren Group Inc

Linear Indication Feature Number	ILI Area Number (From Field Sheets)	Type of Indication	Indication Relative Position*	Indication Radial Position	Axial Start of Indication (mm)	Axial End of Indication (mm)	Axial Length of Indication (mm)	Circ Orientation of Linear Indication (mm)	Clock Position	Indication in Corrosion (Y/N)	Indication Depth (mm)	Indication Depth (%)	Type of Repair	NDT Analysis Method Used to Size Feature	Figure Number

* **IW** - In Weld, **AW** - At Weld (From toe of weld to 10 mm), **BM** - Base Metal (From 11 mm past toe of weld)

Linear Indication Comments

Linear indications were found in the gouges of MD-02 and MD-03. Depths of these linears could not be measured due to their location and length.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2

AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Stress Corrosion Cracking Assessment

SCC Found ☐ Yes ☑ No

SCC Feature Number	ILI Area Number (From Data Sheets)	Feature Areas Inspected	Axial Start of Colony (mm)	Axial End of Colony (mm)	Axial Length of Colony (mm)	Circ Start of Colony (mm)	Circ End of Colony (mm)	Circ Width of Colony (mm)	O'Clock From	O'Clock To	Average Crack Length (mm)	Max Crack Length (mm)	Interacting Axially (Y/N)	Interacting Circ (Y/N)	Longest Interacting Crack Length (mm)	Max Crack Depth (mm)	Max Crack Depth (%)	Significant SCC Colony (Y/N)	Cracking associated with Corrosion (Y/N)	Depth of Colony [Corr. + Crack] (mm)	Depth of Colony [Corr. + Crack] (%)	Was SCC Removed (Y/N)	Type of Repair	Corresponding Feature(s)	Figure Number

SCC Comments

No SCC was found in the area of NDE.

CANSPEC

Pipeline Integrity Field Inspection Report

Trafalgar NPS 42 Dig #2

AGM: NA

Client: Union Gas

Date: October 25, 2005

Girth Weld: Chainage 68m

Dent Assessment

Dent Feature Number	Corresponding Feature(s)	Axial Start of Dent (mm)	Axial End of Dent (mm)	Axial Length of Dent (mm)	Circ Start of Dent (mm)	Circ End of Dent (mm)	Circ Width of Dent (mm)	O'clock From	O'clock To	U/S Pipe Dia. 0°	U/S Pipe Dia. 90°	D/S Pipe Dia. 0°	D/S Pipe Dia. 90°	At Dent Pipe Dia. 0° (DMIN)	At Dent Pipe Dia. 90° (DMAX)	Max Diameter Reduction (Dnom-Dmax)	Ovality (Oval) Dmax Dnom	Half Ovality (Ohalf) 1/2*Oval	Eff. Dent (B) (Rmax-Ohalf)	Dent %	Is the dent sharp? (Y/N)	Is there wall thinning? (Y/N)	Possible Reasons For Dent As Observed

Dent

No dents were found in the area of NDE.

CANSPEC

Pipeline Integrity Field Report

Trafalgar NPS 42 Dig #2
AGM: NA

Client: Union Gas
Date: October 25, 2005
Girth Weld: Chainage 68m

Equipment

ULTRASONICS

Scan Type ☑ A ☐ B ☑ Flaw ☑ Thickness ☐ FAST™

Instrument				Transducer	Type: Single	Type: Dual	Frequency (MHz)	Serial #
Manufacturer	Krautkramer Branson USN52L			0°	☑	☐	15	1685
Serial #	00W566			60°	☑	☐	5	00YY8Y
Cal. Due Date	7-Dec-05			60°	☑	☐	10	0126FR
Range	Various			0°	☐	☑	7.5	FH2E
Transfer Value					☐	☐		
Cal Block	Step Wedge	S/N	113		☐	☐		
Cal Block	Rompas Block	S/N	99-693		☐	☐		
				Other:	☐	☐		
Couplant	Sonoglide Gr 20			Other:	☐	☐		

Scan Type ☐ A ☐ B ☐ Flaw ☐ Thickness ☐ FAST™

Instrument				Transducer	Type: Single	Type: Dual	Frequency (MHz)	Serial #
Manufacturer					☐	☐		
Serial #					☐	☐		
Cal. Due Date					☐	☐		
Range					☐	☐		
Transfer Value					☐	☐		
Cal Block		S/N			☐	☐		
Cal Block		S/N			☐	☐		
				Other:	☐	☐		
Couplant				Other:	☐	☐		

MAGNETIC PARTICLE

MPI Equipment

Manufacturer	Type	S/N	Cal. Due Date
Parker	B 300UF	9452	30-Nov-05

Magnetizing Method ☑ AC or ☐ DC ☑ Continuous or ☐ Residual ☐ Yoke ☐ Coil

	Name	Signature	CGSB Number
Technician	James Allen	On File	10019
Technician	Joseph Lui	On File	

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

01) East View of Excavation

02) South East View of Excavation

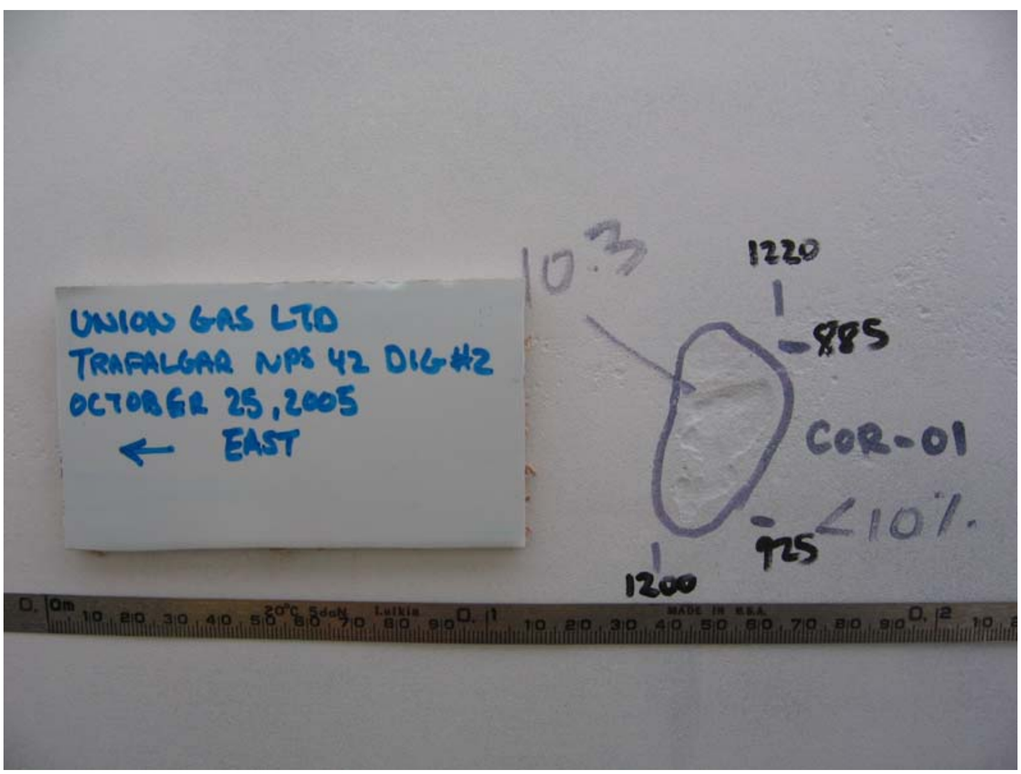
Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

03) North East View of Excavation

04) Soil Pile

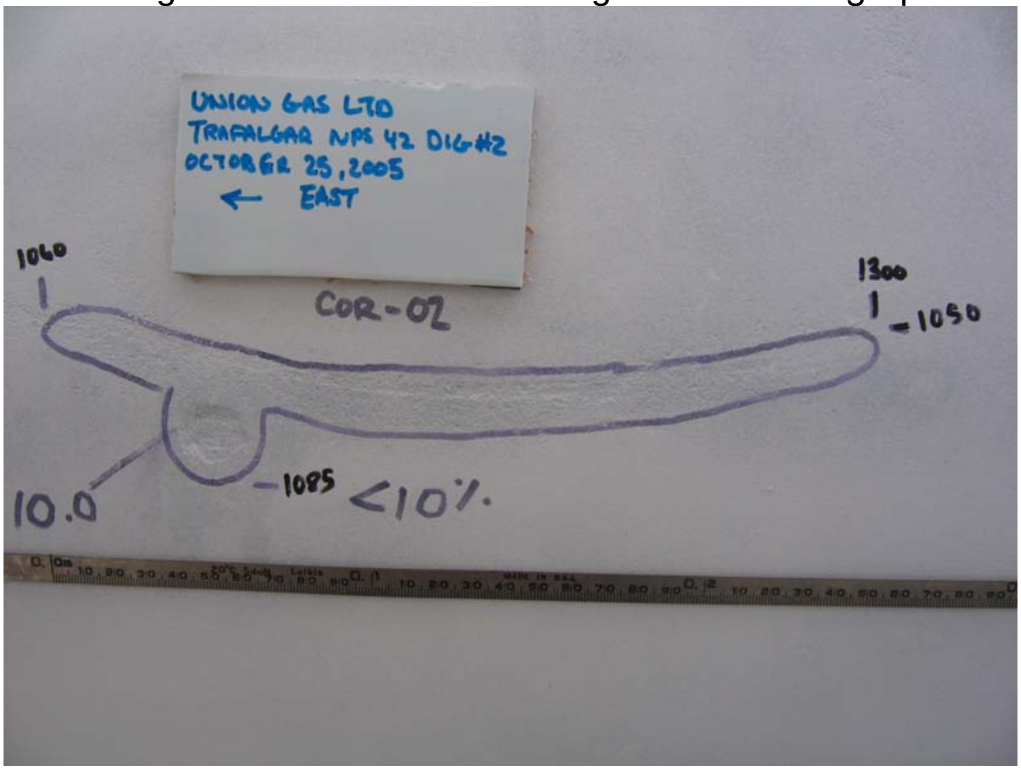
Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

05) Soil

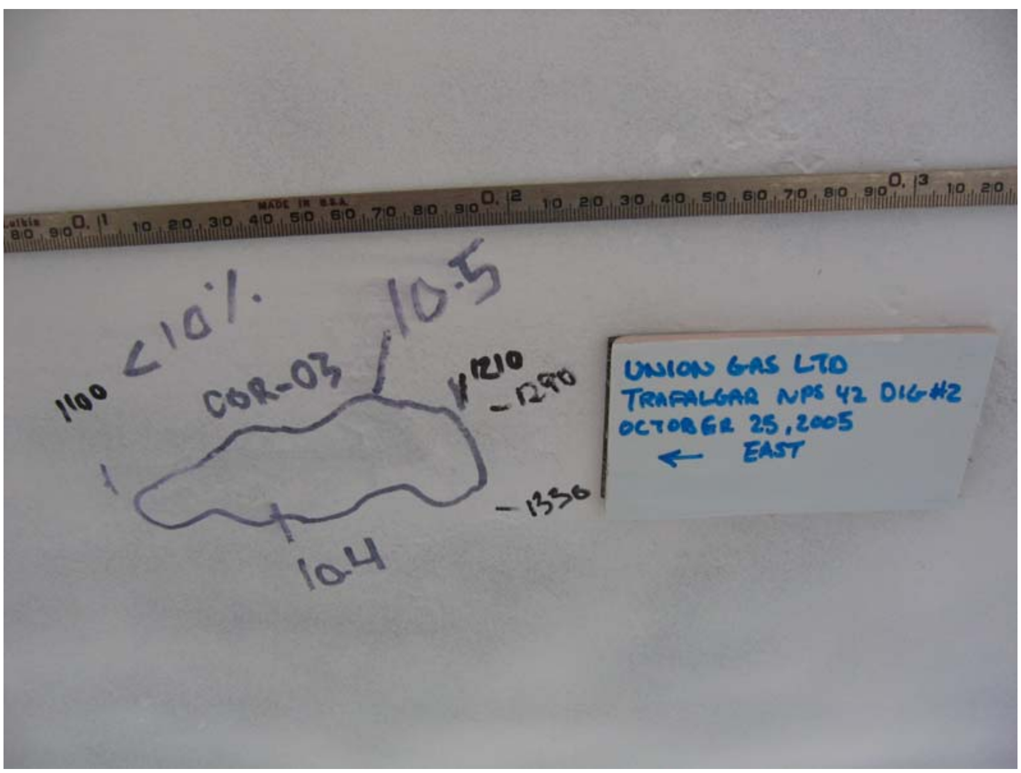


06) COR-01

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

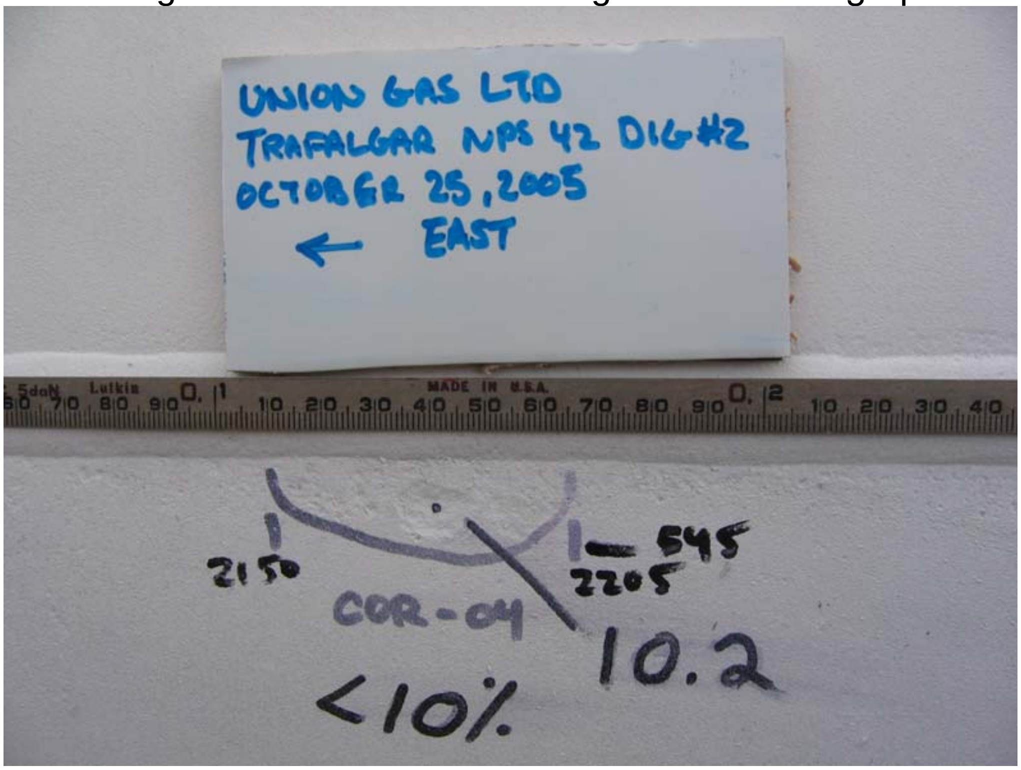


07) COR-02

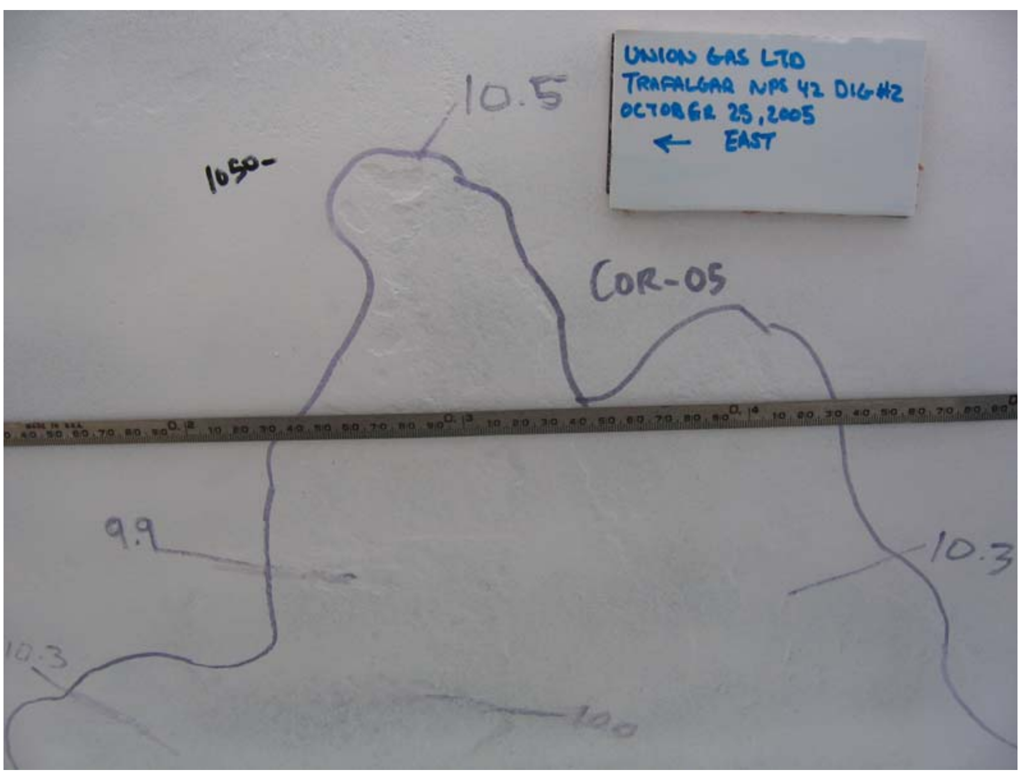


08) COR-03

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

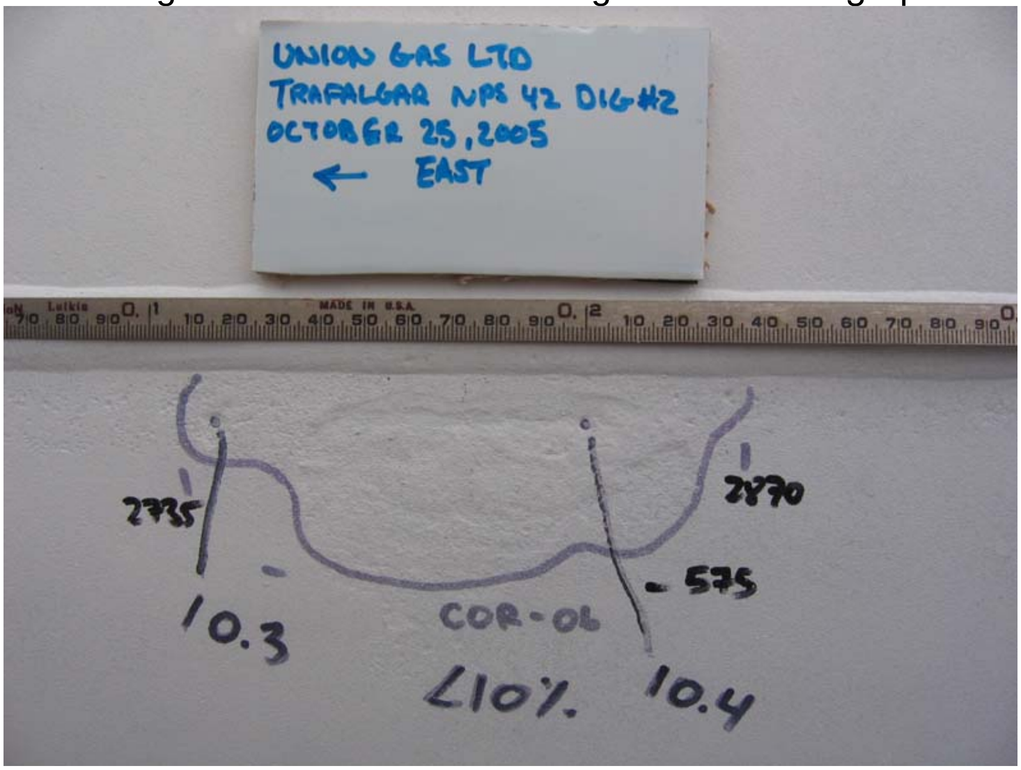


09) COR-04

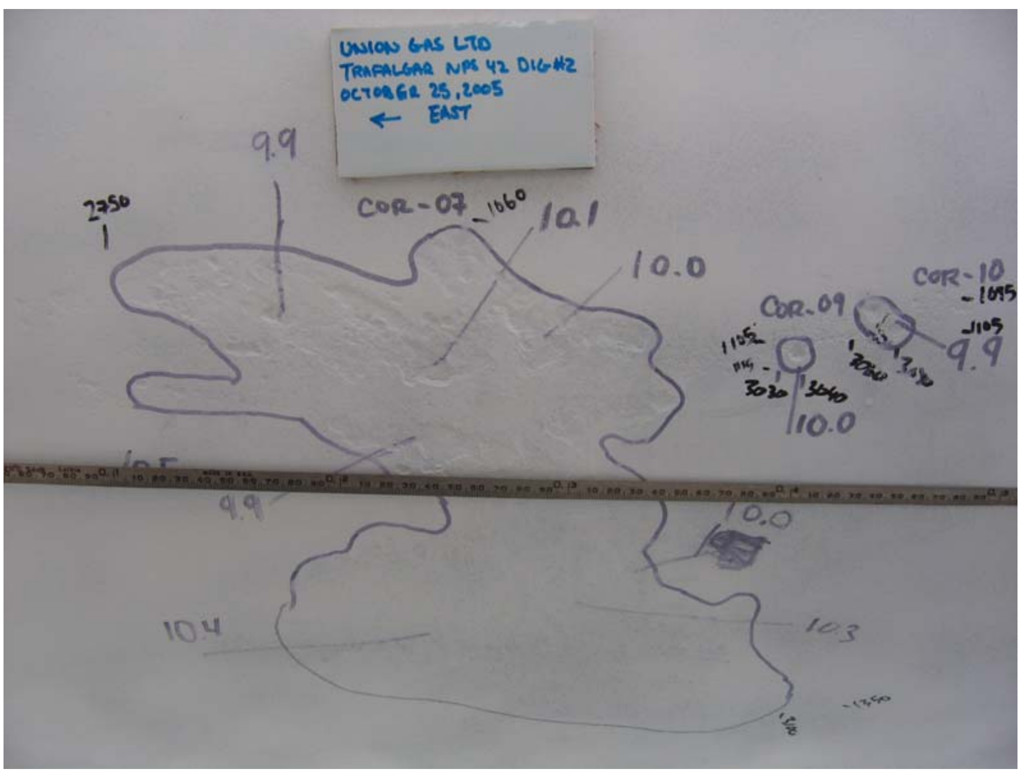


10) COR-05

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

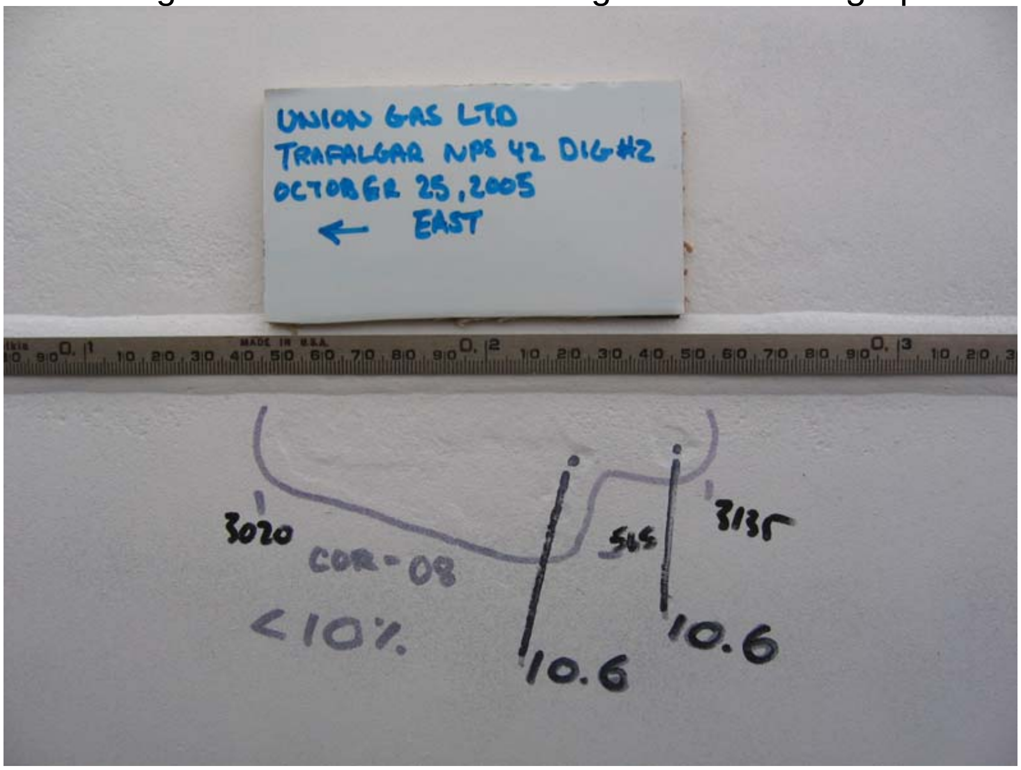


11) COR-06

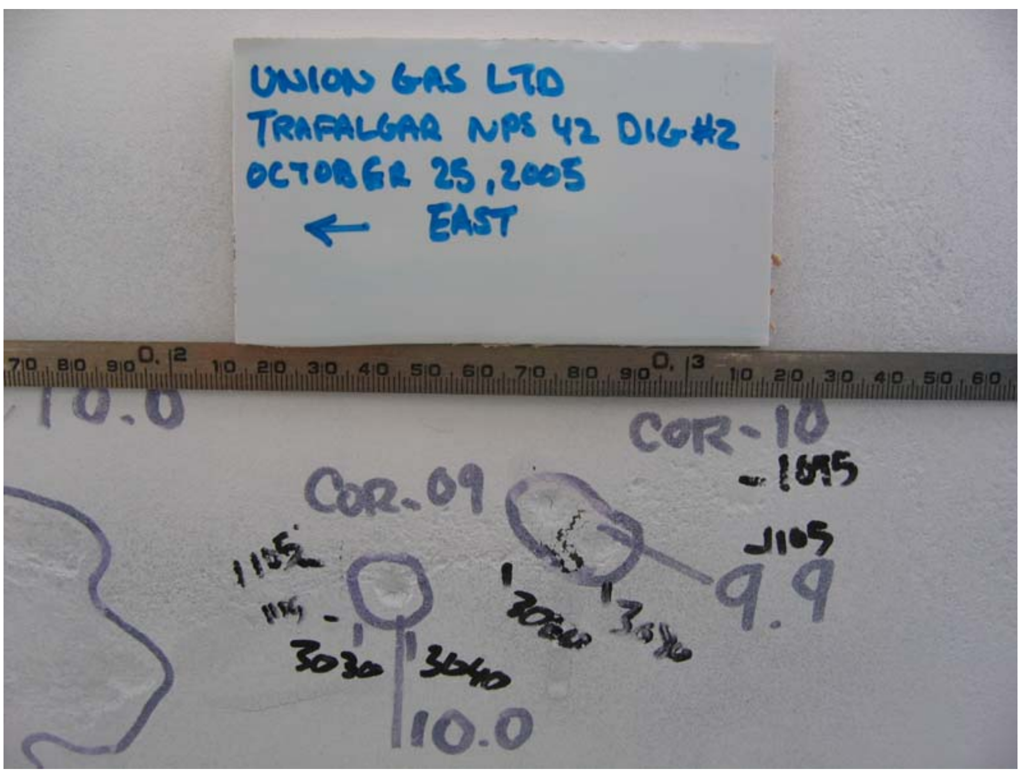


12) COR-07

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

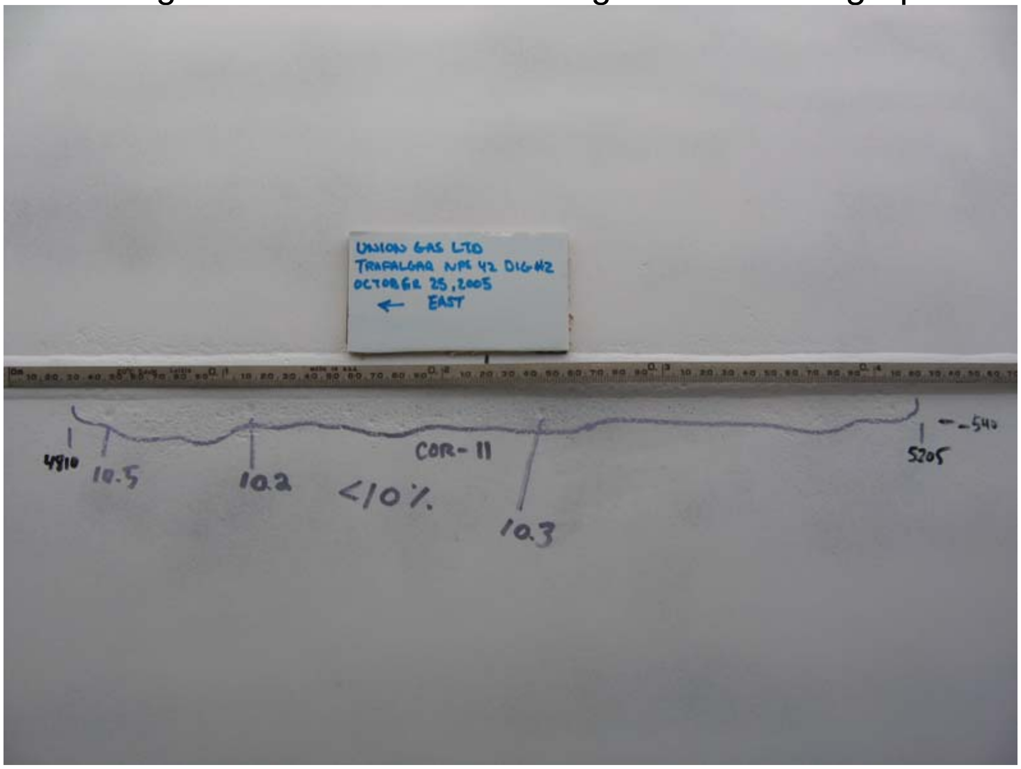


13) COR-08

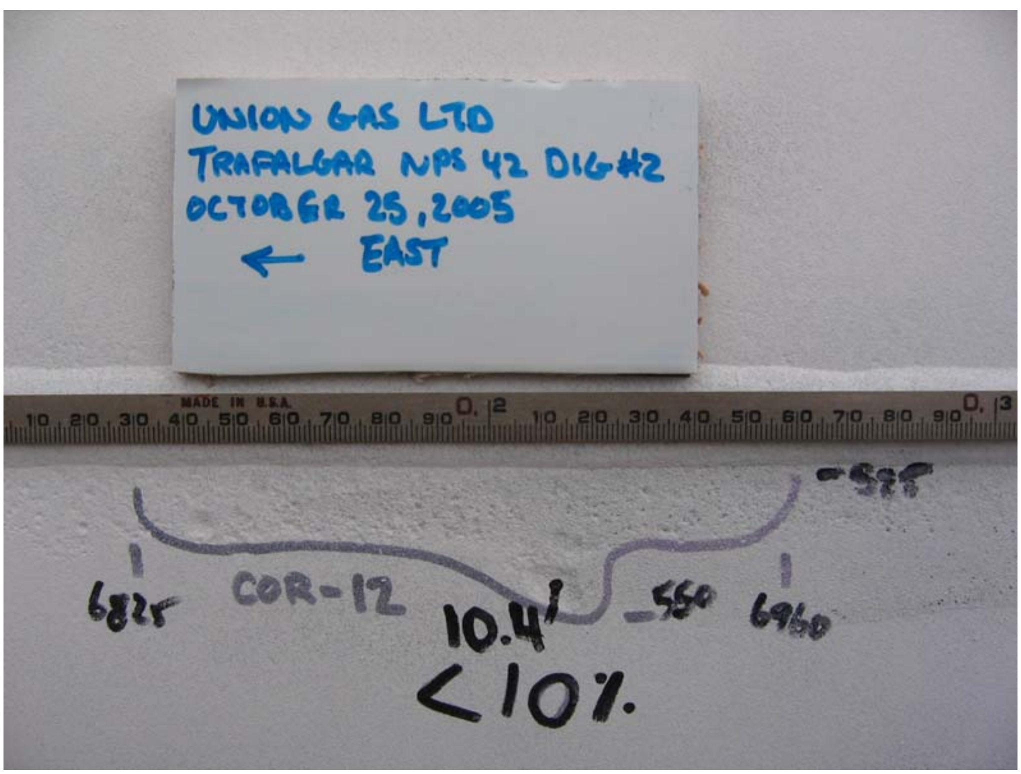


14) COR-(09,10)

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

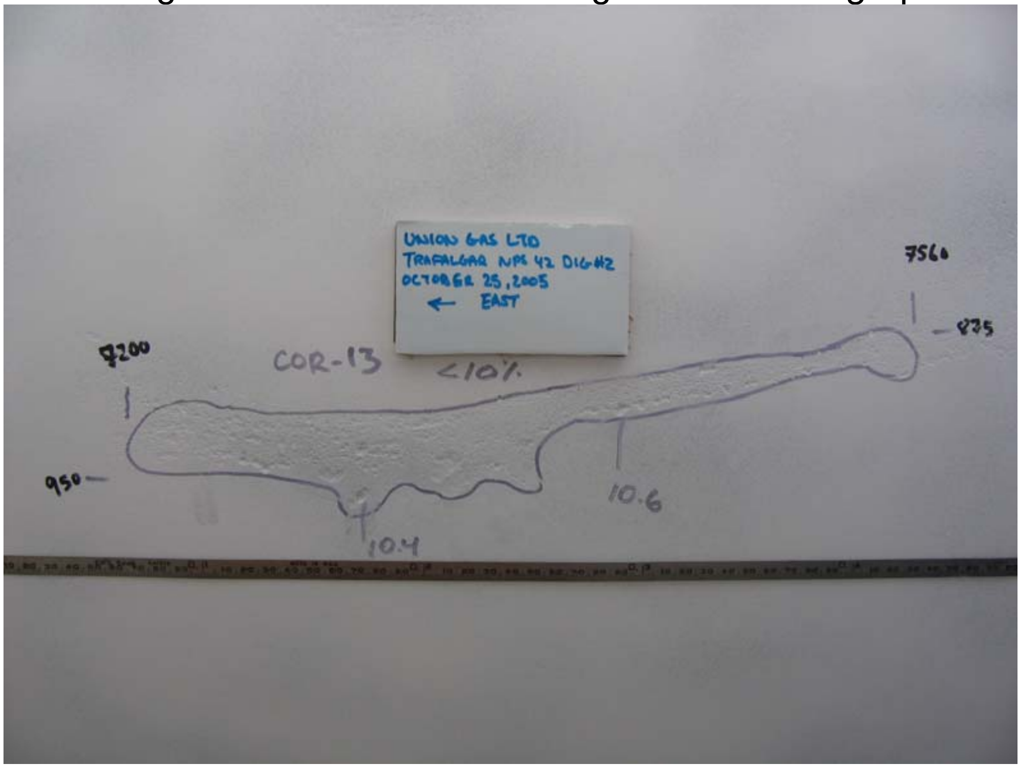


15) COR-11

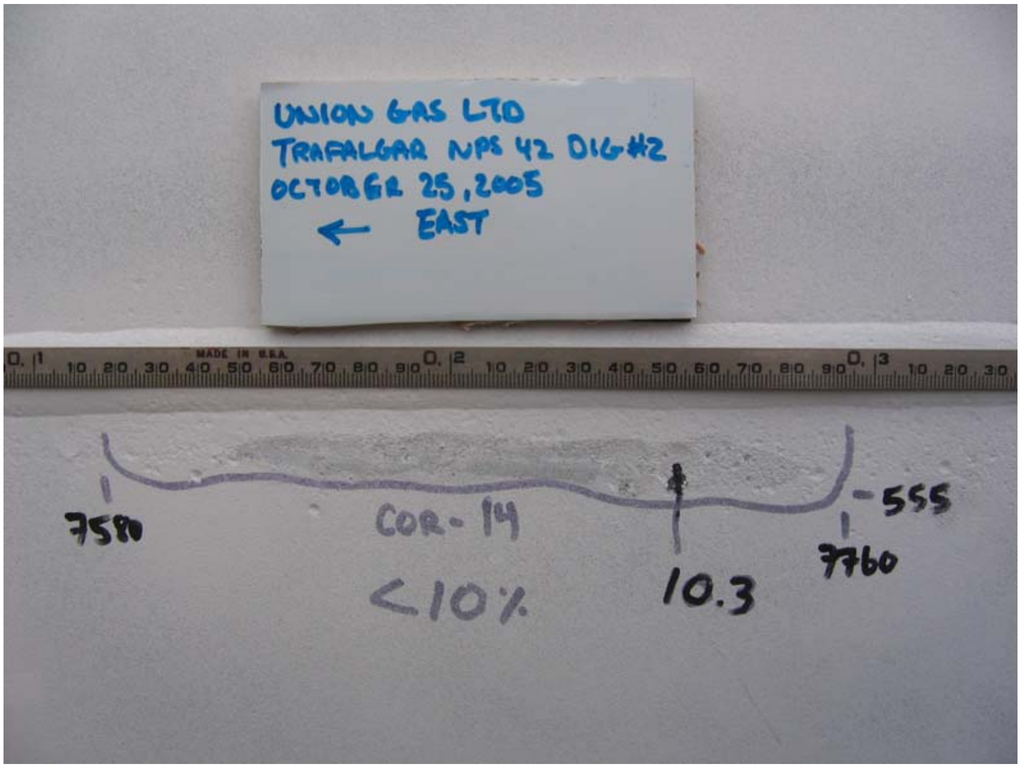


16) COR-12

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

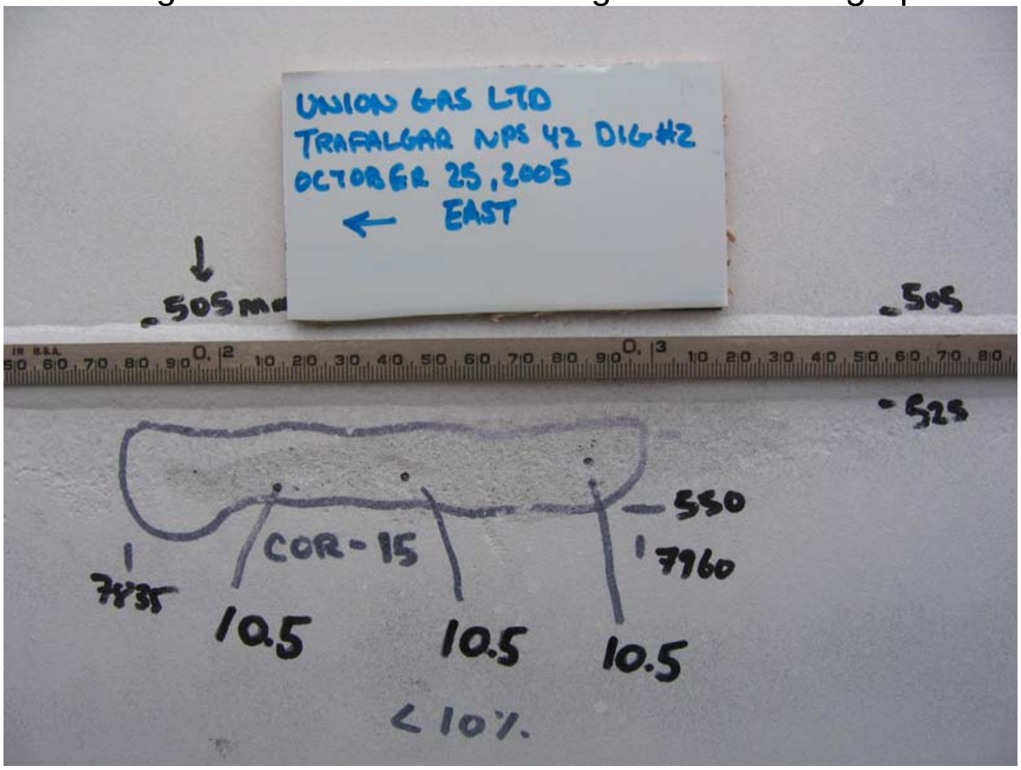


17) COR-13

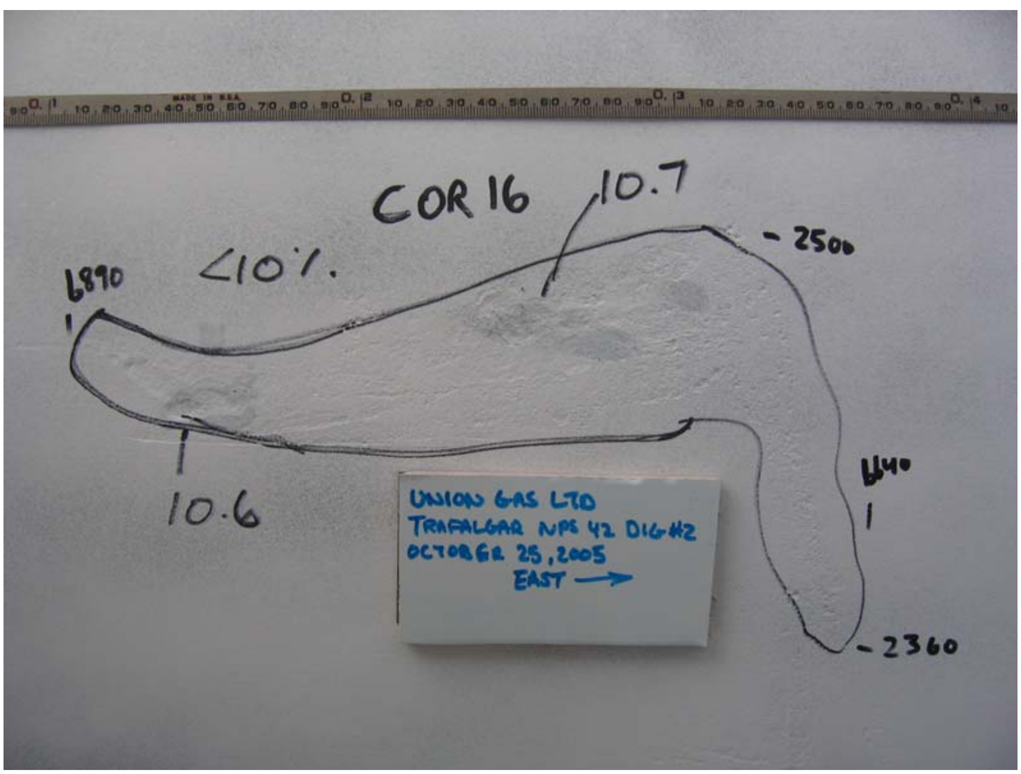


18) COR-14

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

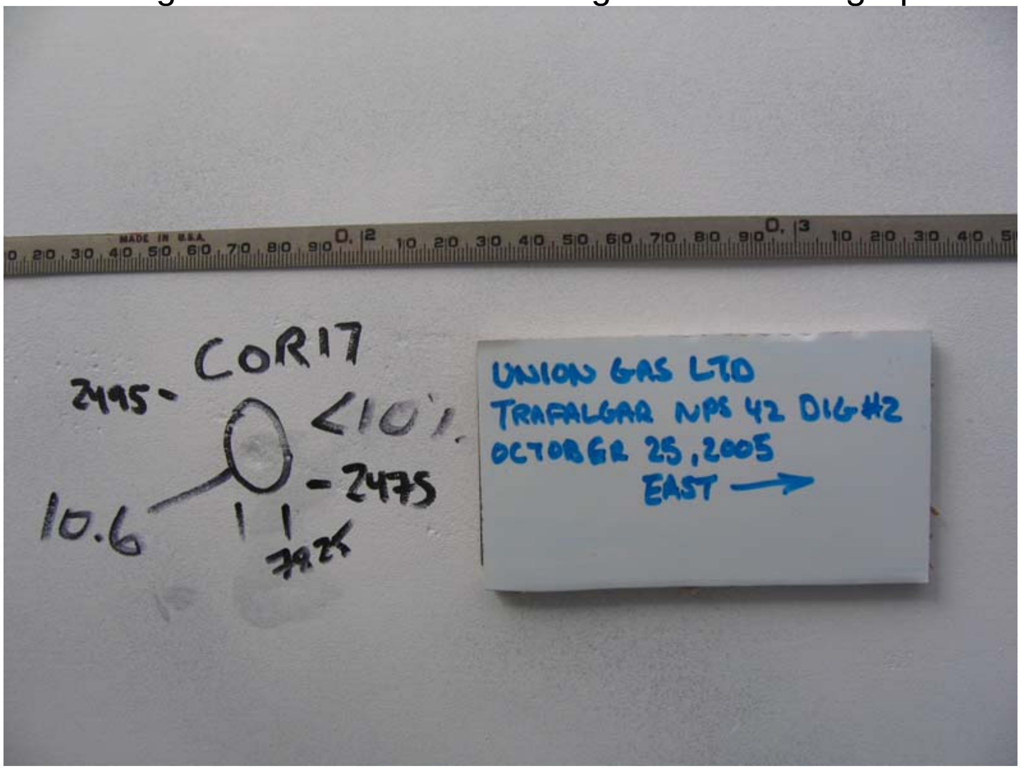


19) COR-15

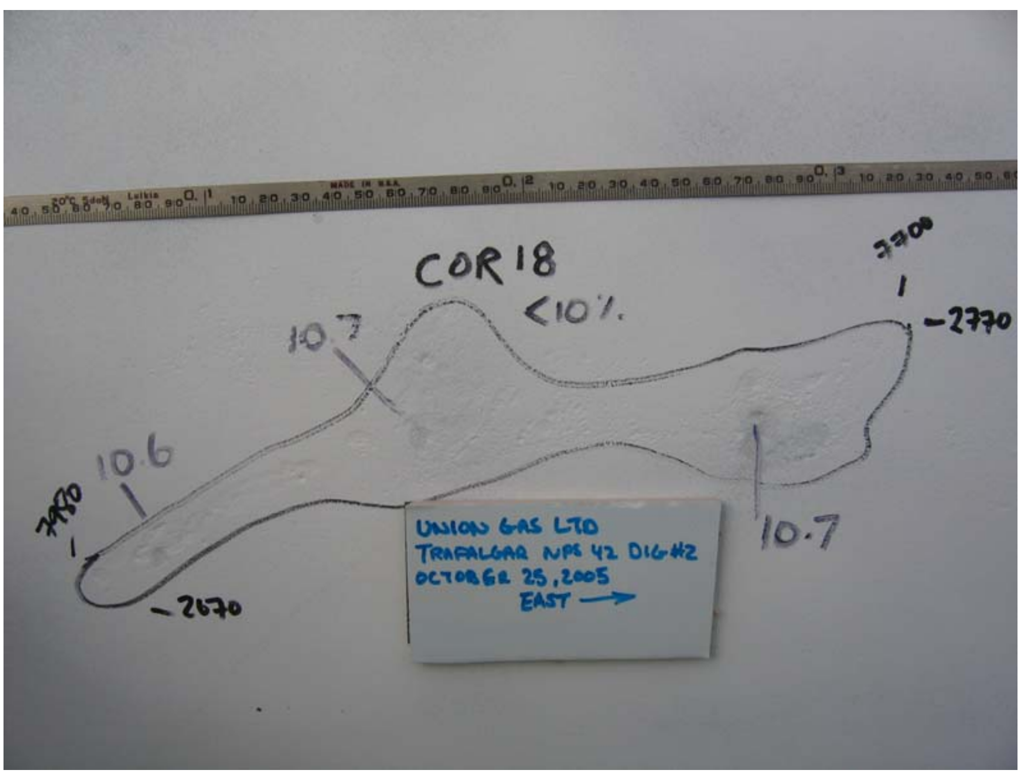


20) COR-16

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

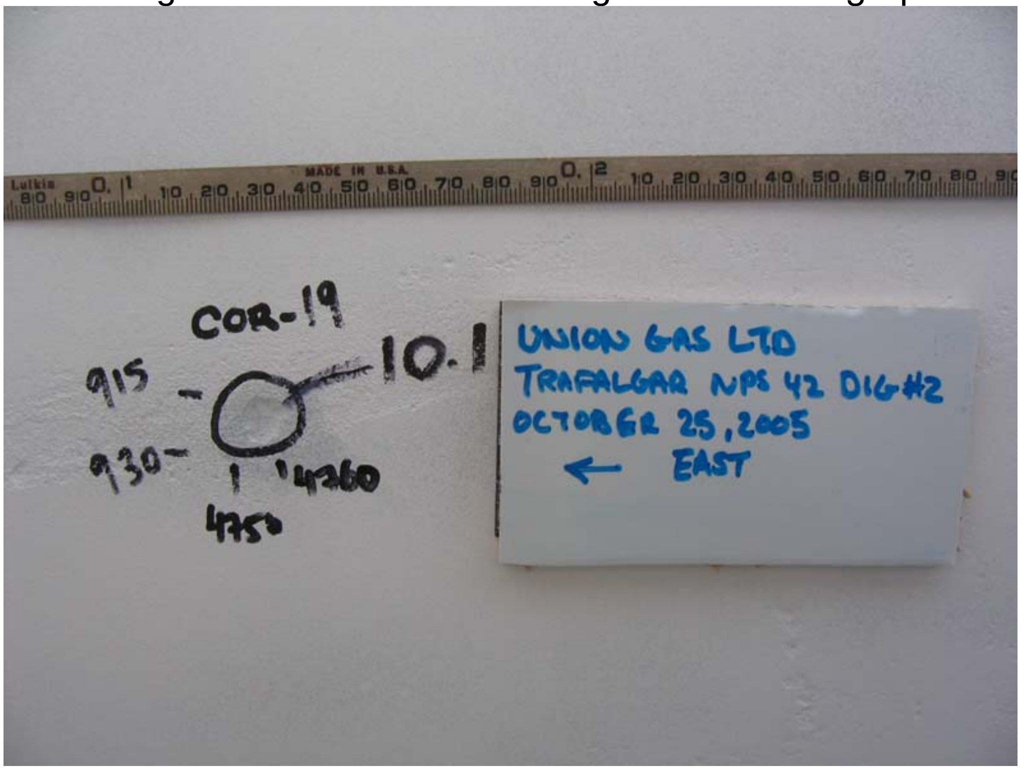


21) COR-17

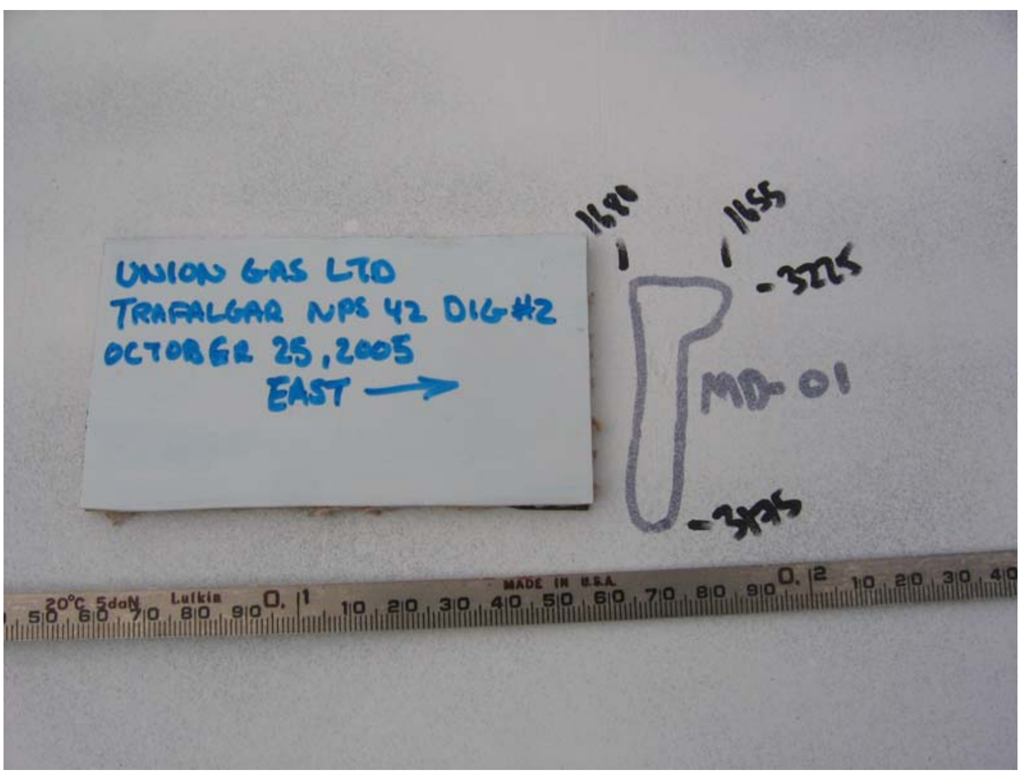


22) COR-18

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

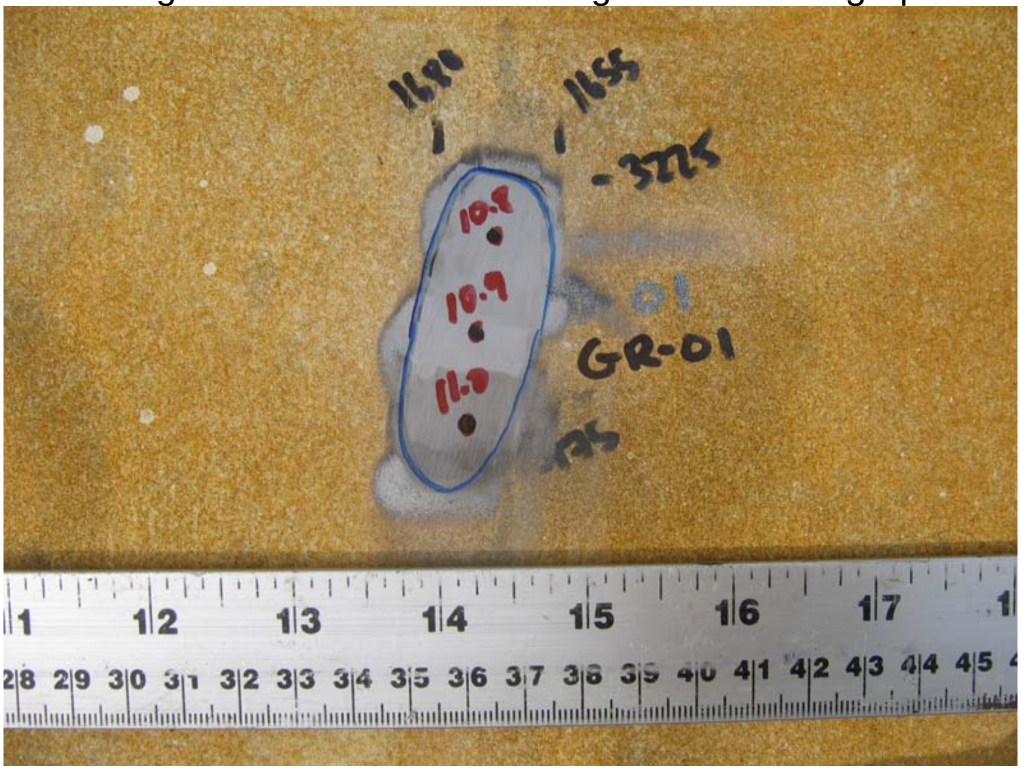


23) COR-19

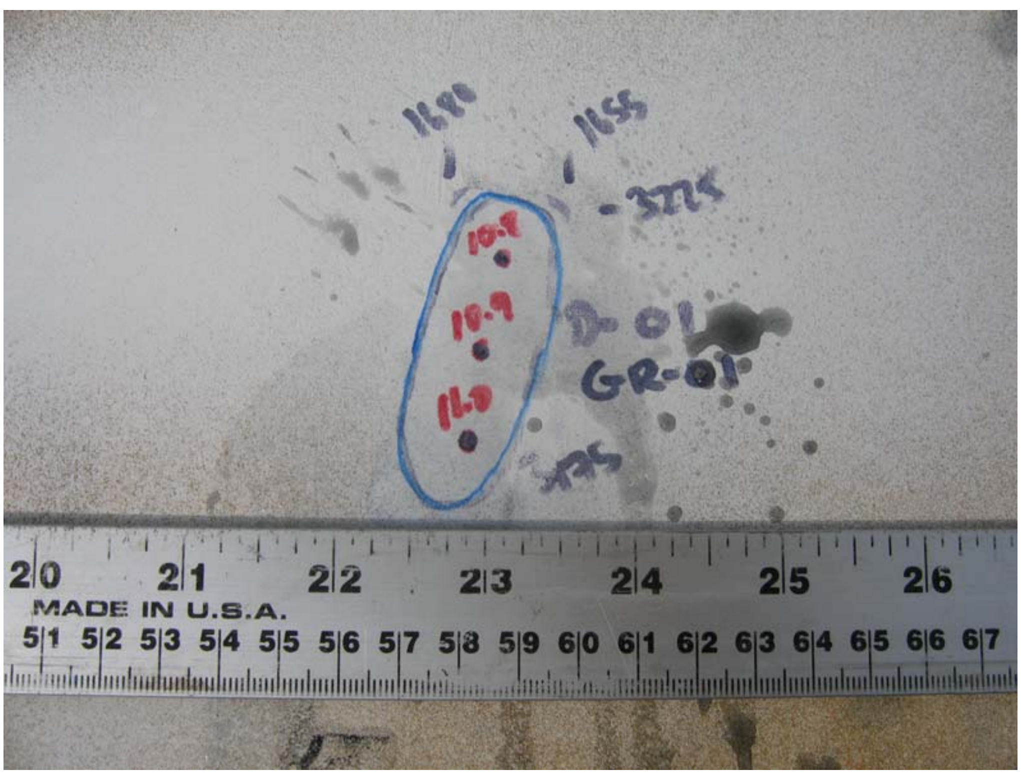


24) MD-01

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

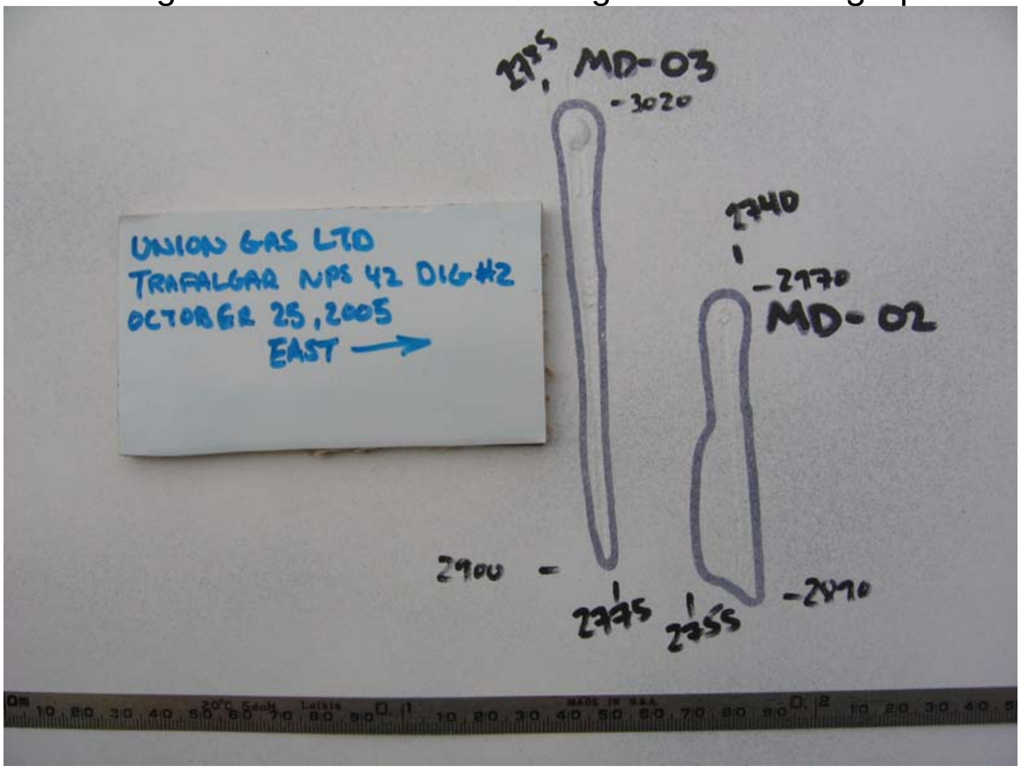


25) GR-01

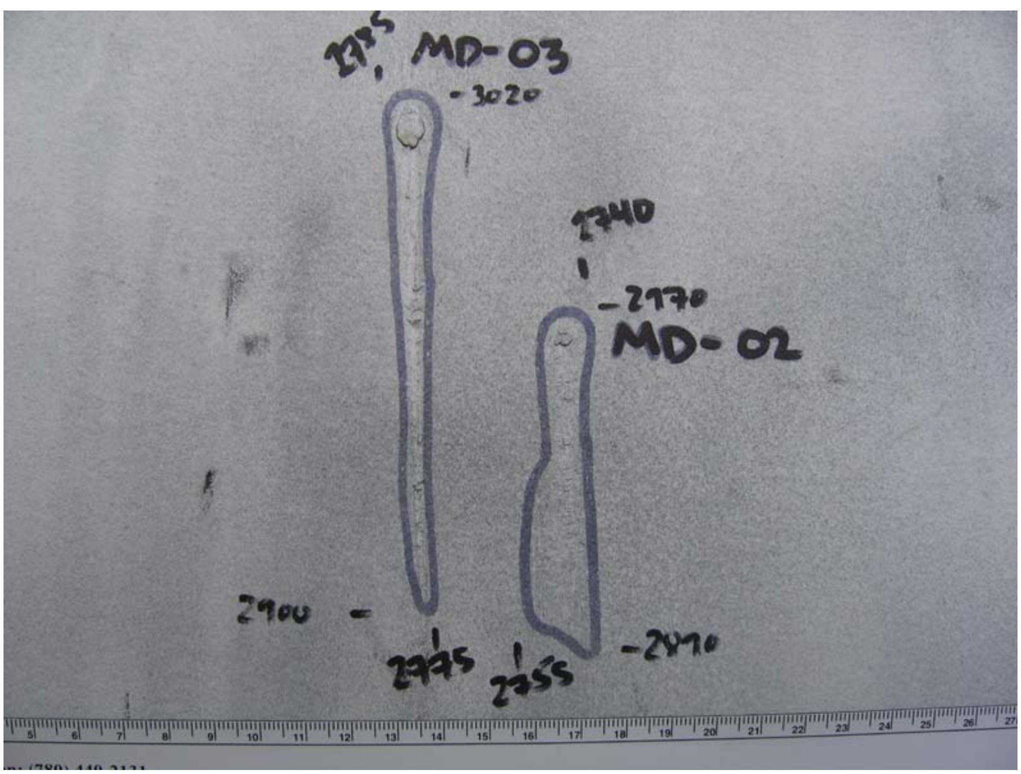


26) GR-01 Magnetic Particle

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

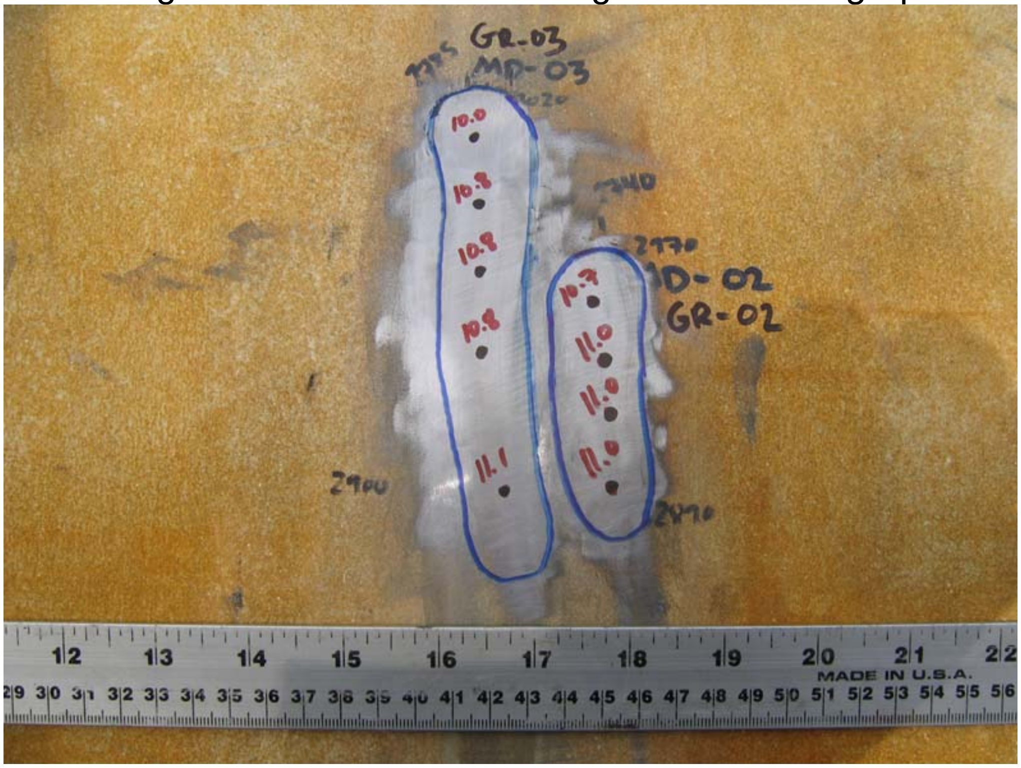


27) MD-(02,03)

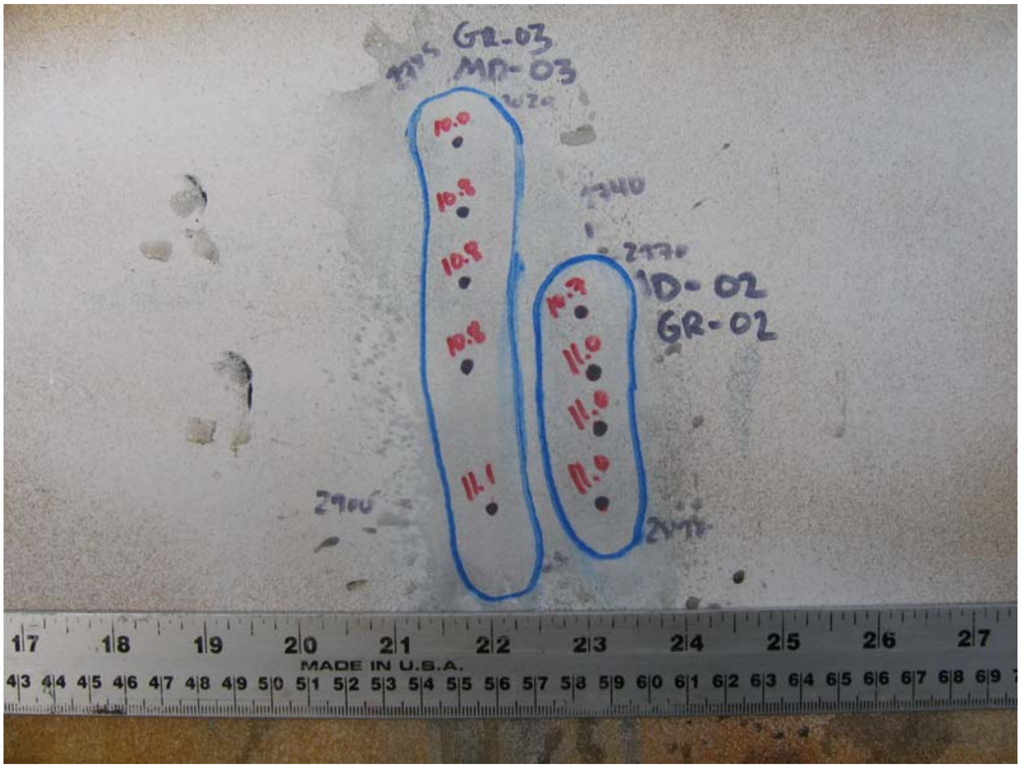


28) MD-(02,03) with Linear Indications within Gouges

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

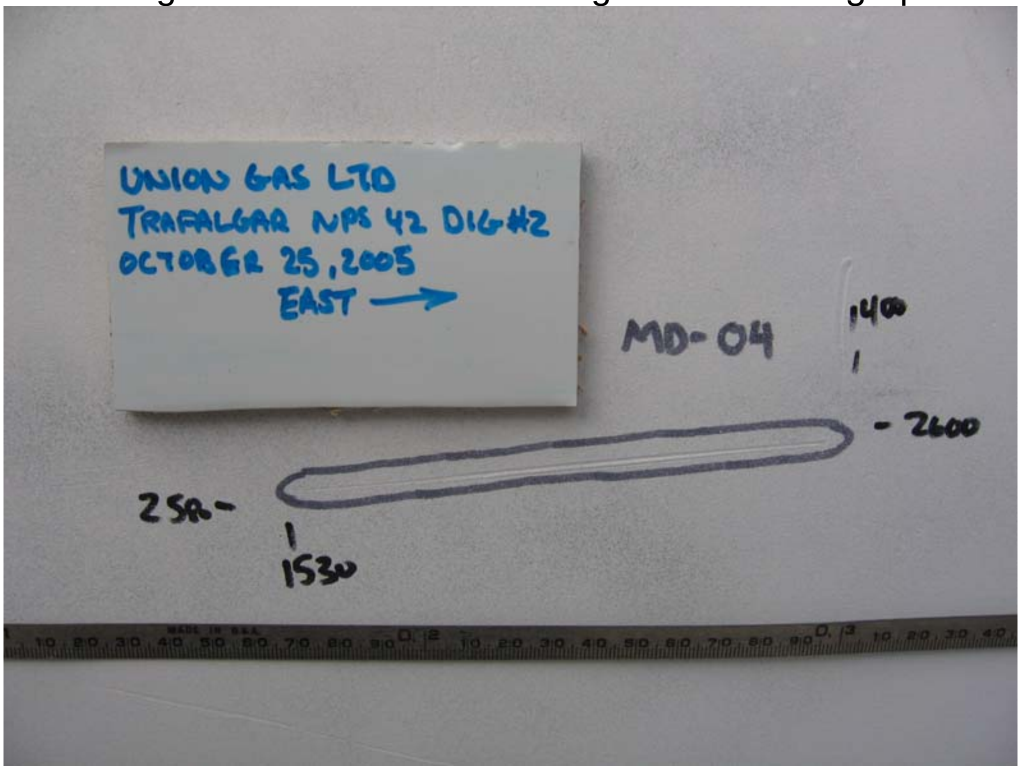


29) GR-(02,03)

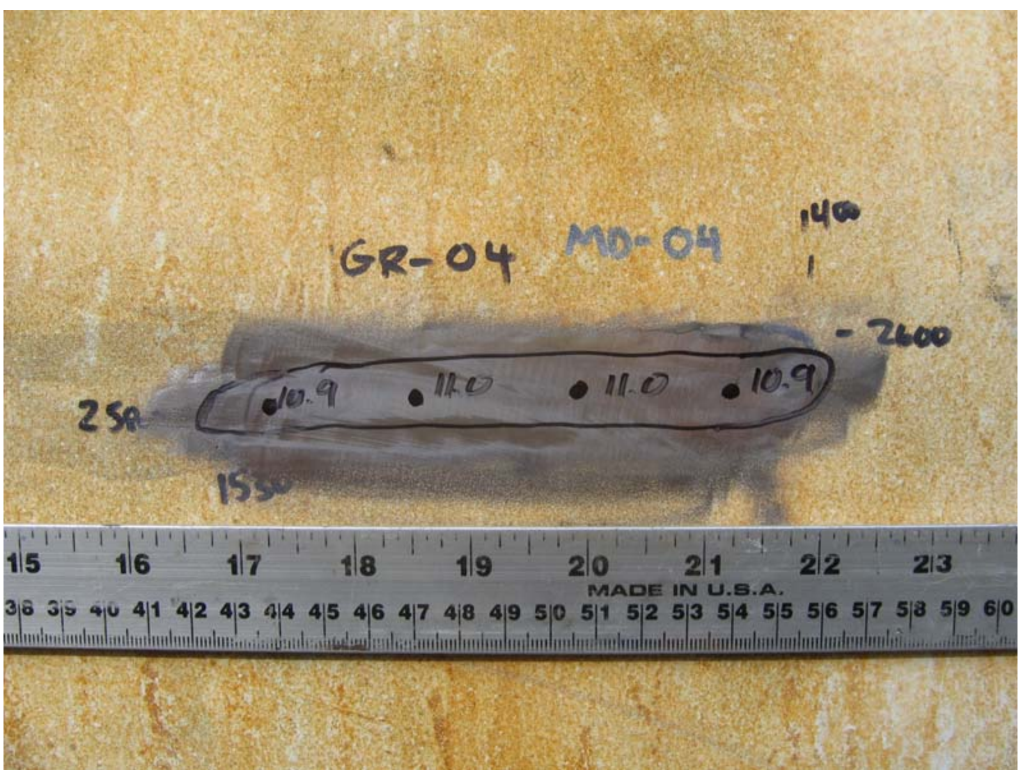


30) GR-(02,03) Magnetic Particle

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

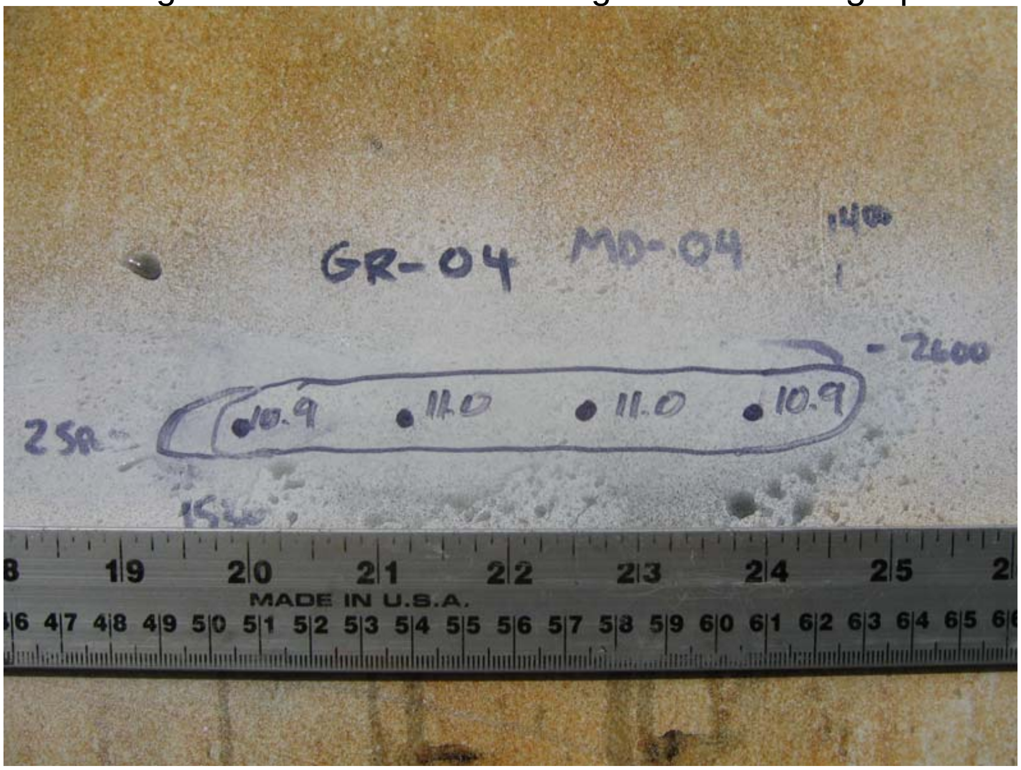


31) MD-04

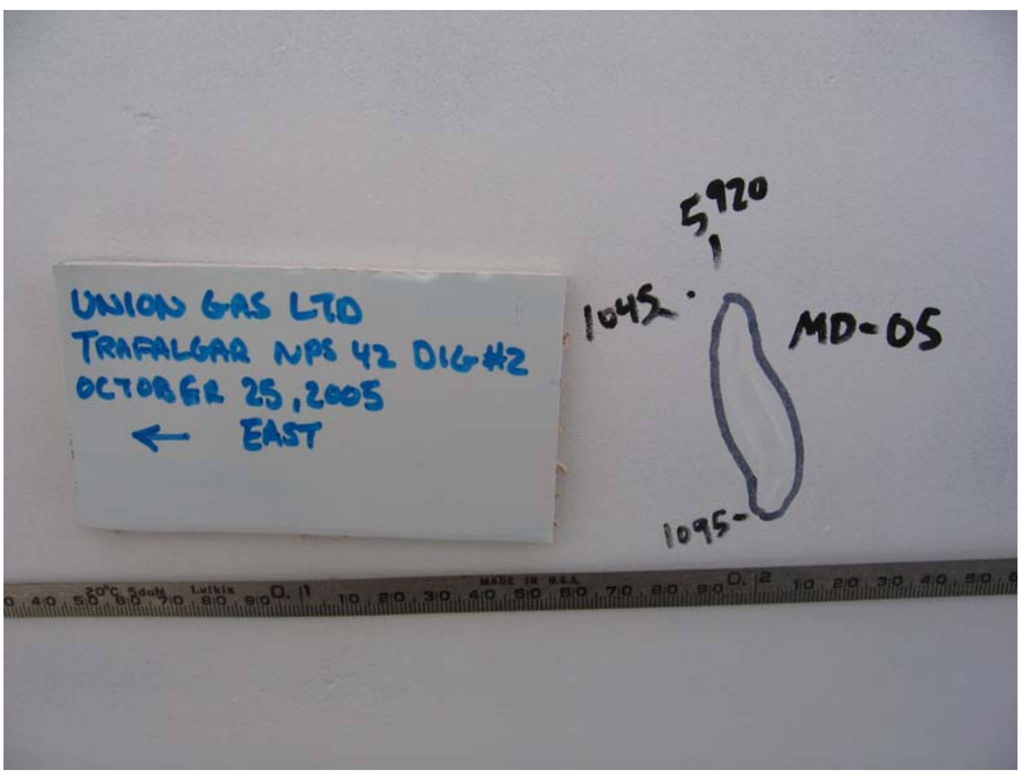


32) GR-04

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs

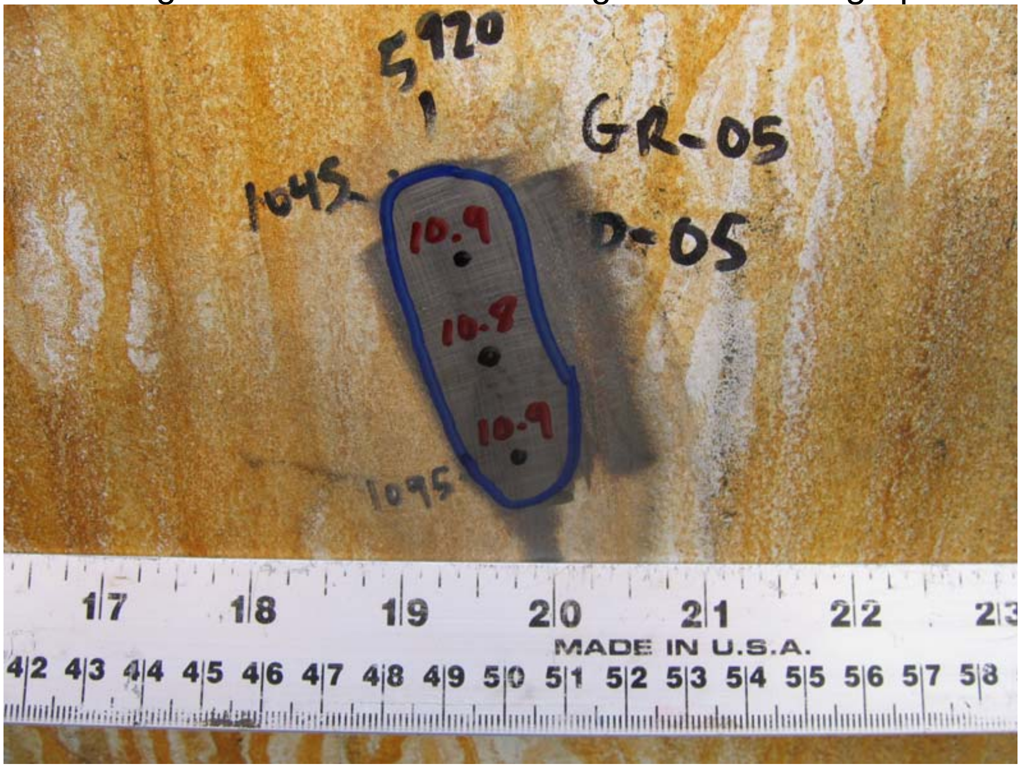


33) GR-04 Magnetic Particle

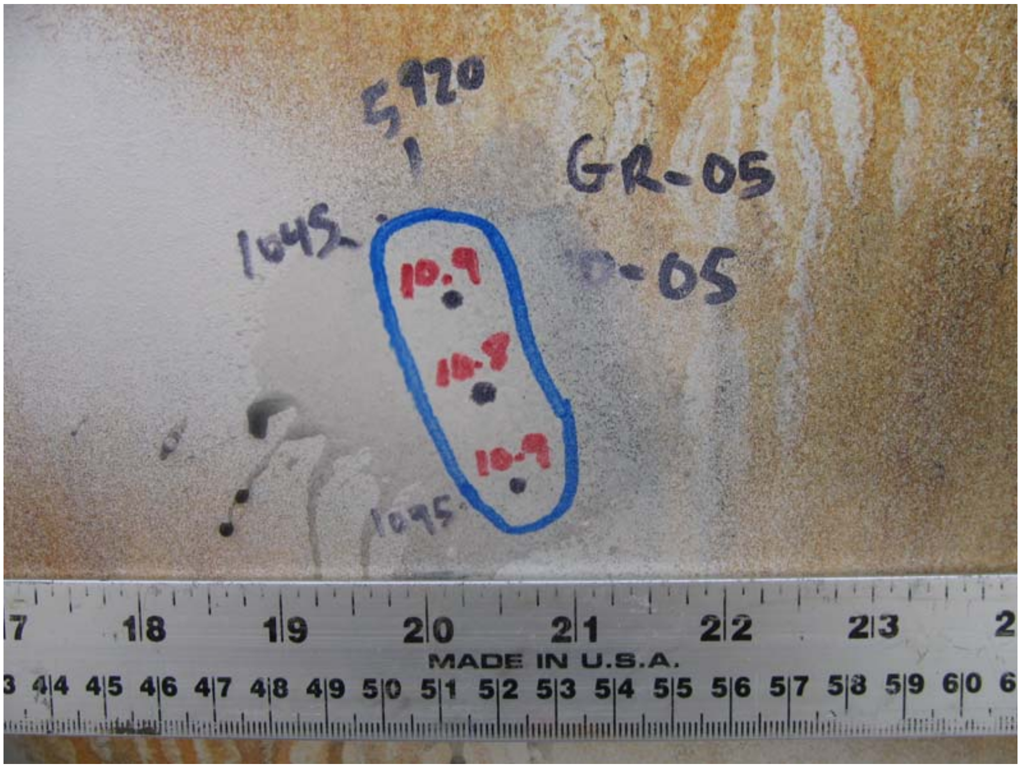


34) MD-05

Trafalgar Line NPS-42 ECDA Dig Site #2 Photographs



35) GR-05



36) GR-05 Magnetic Particle

NPS 42 Trafalgar Site 2 Remediation Action

SCC : CARS# 151068
YO# 341593

Gord Phipps

From: Rob Marson
Sent: October 31, 2005 4:54 PM
To: Steve Gonneau; Pat Sarrazin; Jason Bohn
Cc: Gord Phipps; Chris Falconer; Scott Walker -Eng; Mark Lacina; Ron Grozelle
Subject: FW: Remediation - NPS 42 ECDA Dig #2

Here is the remediation plan for dig #2 on the NPS 42. Note the pressure in the line has been reduced to less than 400 psig. The plan is to have Acuren (Canspec) work on site 1 to remove the imperfections noted below. At no time should the grind length or depth exceed the recommendation without first consulting with Pipeline Engineering.

If you have any questions please contact myself or Ron Grozelle.

Rob Marson, P.Eng.,
Senior Construction Engineer
Union Gas Limited
rmarson@uniongas.com
office: 519-436-4600, x2077
cell: 519-365-2726
pager: 519-355-2139

From: Ron Grozelle
Sent: October 31, 2005 11:33 AM
To: Rob Marson
Cc: Ken Jeans; Tom Hamilton; Rod Reid; Mike Whitehouse; Mike Whitehouse
Subject: Remediation - NPS 42 ECDA Dig #2

The following is the remediation for Dig #2.

Remediation Action Report

Pipeline Name: Trafalgar Line NPS-42 ECDA
Site Location: Dig #2 Chainage 68m

Attachments: Canspec report – October 25, 2005

Psafe - 5122 kpa (743 psig)

SCC Features:

No SCC features detected. .

Linear Indications/Laminations/Hooks:

There were two (2) Linear Indications found in gouges (MD-02 & MD-03).

Remedial Action:

1. Grind/Buff linear indication following approved grind procedure specification using rubber-backed 80 – 120 grit buffing disc, to a **maximum of 14% (1.6 mm)** actual wall thickness.
   Grind lengths shall be kept to a minimum and shall not exceed **560 mm**, while ensuring a smooth transition back to the pipe surface.
2. Mag Particle the grind area of the pipe to ensure that the defect has been removed.
   Measure the remaining wall thickness and grind length. Examine the grind area and note if there are any other features or anomalies within the grind area.
3. Contact Pipeline Engineering – Ron Grozelle for further action.

1

Corrosion Features:

There were thirteen (13) corrosion features detected less than 10%. Six (6) corrosion features were found with between 10% to 12% wall loss. No remediation required.

Mechanical Damage Features:

There are five (5) scrapes/gouges. Buff the gouges following approved grind procedure specification using rubber-backed 80 – 120 grit buffing disc, to a **maximum of 10% (1.1 mm)** actual wall thickness. Grind lengths shall be kept to a minimum, while ensuring a smooth transition back to the pipe surface.

Mag Particle the grind area of the pipe to ensure that the defects have been removed. Measure the remaining wall thickness and grind length. Examine the grind area and note if there are any other features or anomalies within the grind area.

Dents:

No dents found

Arc Burns:

There were three (3) arc burns detected. Buff the arc burns following approved grind procedure specification using rubber-backed 80 – 120 grit buffing disc, to a **maximum of 10%** actual wall thickness. Grind lengths shall be kept to a minimum, while ensuring a smooth transition back to the pipe surface.

Re-inspect the buffed area using 5% Nital etch to ensure complete removal of the arch burn. Mag Particle the grind area of the pipe to ensure that the defect has been removed. Measure the remaining wall thickness and grind length. Examine the grind area and note if there are any other features or anomalies within the grind area.

Ron Grozelle, P.Eng.,
Senior Pipeline Engineer
Operations Technical Support
Pipeline Engineering
Ph: 1-519-436-5247
Cell: 1-519-365-0713
Fax: 1-519-436-5292
e-mail: rgrozelle@uniongas.com

NDT Group Inc.
20 Roy Blvd. Unit 30/31
Brantford, ON, Canada
N3R 7K2
Phone: (519) 304-9199
Fax: (519) 304-8199
www.ndtgroup.ca

Pipeline Integrity - Final Report

Enbridge Gas Inc.

Trafalgar NPS42

Investigative Dig Site 1

TJ

3012 Bentpath Line

September 3, 2019

Proudly Canadian

Pipeline Integrity Field Report

NDT group.ca

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Project Information

Project: Trafalgar NPS42
NPS 42
ILI Target: N/A
Dig # or Site Reference: Investigative Dig Site 1
P.O. #: TBA
Ref GW Absolute Dist: N/A

Site Information

Reference GW: TJ
Contractor: Aecon
Year of Construction: N/A
Measurement Ref.: Upstream GW (+)
GPS Co-ordinates: 42.716593, -82.215714
Township: Tupperville, ON
Street Address: 3102 Bentpath Line

Pipe Information

Pipe OD (mm): 1066.8
Pipe OD (in): 42
Nominal WT (mm): 11.1
Pipe Grade: 448 (X65)
Design Factor: 0.72
MOP (kPa): 6160
Code/Standard: CSA Z662

ILI Information

ILI Tool Run Date: N/A
ILI Technology: N/A
ILI Tool Vendor: N/A
Reason for Dig: N/A
ILI Target GPS: N/A

Pipe Data

GW Number Exposed	Girth Weld Type	Type of Exposure	ILI Joint Length (m)	Actual Joint Length (m)	LS Type	Predicted LS (Degrees °)	Actual LS (mm)	Actual LS (Clock)	Actual LS (Degrees °)
USTJ	N/A	Partial	N/A	N/A	DSAW	N/A	385.0	1:22	41
TJ	SMAW	Partial	N/A	N/A	DSAW	N/A	3185.0	11:24	342

Pipe UT Thickness Readings (mm)

Joint Section GW	Upstream U/S				Downstream D/S				Avg. UT Wall Thickness
	0°	90°	180°	270°	0°	90°	180°	270°	
USTJ	N/A	N/A	N/A	N/A	11.2	11.2	11.2	11.2	11.20
TJ	11.1	11.2	11.2	11.2	11.2	11.2	11.2	11.3	11.20

Cathodic Protection Readings (mV)

Joint Section GW	Upstream U/S		Downstream D/S		Average
	90°	270°	90°	270°	
USTJ	N/A	N/A	-1141	-1147	-1144
TJ	-1142	-1146	-1149	-1146	-1146

NGI Technicians:

Name: Simon Susac Certification: CGSB UT2/MT2
Name: Christian Forero Certification: CGSB UT1

Cert# 13934
Integrity Lead Signature:

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 1
Field Report Summary

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Soil, Coating, Groundwater, and Environmental

There was a total of 6 Coating Defect Features identified during the coating assessment. CD-01 was intermittent disbondment at the seams of the coating wrap and was present throughout the exposed joint. CD-02 (Upstream Joint) and CD-03 (Target Joint) were identified as tenting on the DSAW long seam welds. CD-04 to CD-06 were significant wrinkles with corrosion deposits underneath. CD-04 and CD-05 interacted with the reference girth weld TJ and were located on the 3:00 and 9:00 sides respectively. CD-06 was wrinkling in the pipe body. Electrolytes were identified at CD-06 which had a PH reading between 8 and 9. General wrinkles on coating were noticed throughout the exposed pipe. Refer to pictures for coating details. Corrosion deposits were noted at these areas of disbondment which consisted of hard white deposits, orange/black deposits and some areas of pasty white deposits. The black/orange corrosion deposits were slightly magnetic, the hard white and pasty white deposits were not. Refer to the close up photos of the corrosion deposits at each coating defect for additional details.

ILI Target Defect

This is an unpiggable line section, no ILI Targets or joint lengths available.

Corrosion Assessment Summary:

There was a total of 4 corrosion features noted in the NDE assessment area. COR-01 is the longest and deepest corrosion feature with a length of 275mm and lowest remaining wall of 9.2mm. The lowest remaining wall was a small pit, the majority of the corrosion feature was <15% deep and consisted of small pits. COR-01 was associated with GW TJ due to interaction rules, however no pits were found to be directly interacting with the girth weld. COR-01 was also correlated with CD-04. COR-02 to COR-04 were located in the base metal and were not associated with any other features. No further repairs were required, site to be recoated.

Metal-Loss Assessment Summary:

Refer to corrosion page.

Mechanical Damage Summary:

There was a total of 20 damage features noted in the NDE assessment area consisting of 9 gouge/scrape features and 11 scab-like features. DF-07 is considered to be interacting with the reference girth weld GW TJ due to interaction rules, however the feature is approximately 7mm from the girth weld. No grind remediation has been performed to date. All damage features were successfully removed as per the Enbridge Gas Engineering remediation report for this site. No further repairs were required, site to be recoated.

Linear Indication Assessment Summary:

None reported.

Dent Summary:

None reported.

SCC Assessment Summary:

There was a total of 3 SCC features. The longest SCC colony was SCC-03 with a length of 34mm, and longest interacting crack length of 4mm. SCC-01 and SCC-02 showed no axial or circumferential crack interaction so the average crack length is also the longest crack length (2mm). No depth sizing was possible on the SCC features which indicates the features are likely less than 10%NWT. No grind remediation has been attempted to date. All SCC features were successfully removed by grind remediation as per the Enbridge Gas Engineering repair recommendation for this site. All features had maximum crack depths of 0.2mm. No further repairs were required, site to be recoated.

Grind Assessment Summary:

23 grind repairs were required to repair features as outlined in the EGI Remediation report for this site. All features were successfully removed within the requirements as outlined in the remediation report. All grind repairs were found acceptable by Enbridge Engineering, site to be recoated.

Remediation Summary:

Grind repairs were performed on reported anomalies per client request, refer to Grind Summary above and Grind Sheet for further details. Client indicated the exposed section was to be recoated and backfilled.

Additional Comments:

This dig site assessment was completed as per Enbridge Gas Procedure 'Practice 407 SCC Management' as part of an investigative dig program of the unpiggable line section between the Trafalgar Valve Nest at Dawn Station and Cuthbert Station . The dig location was selected by field personnel and is approximately 103m East of the Eastern Fence Line at the Trafalgar Valve Nest. Flow direction was recorded from Cuthbert Station to Dawn Station as per Enbridge Gas Engineering. In the interim report GW1000 was used as the reference name for the exposed girth weld. The girth weld name has been changed to TJ (Target Joint) as requested by Enbridge Gas Engineering.

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 1

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Equipment and Work Scope

Ultrasonic Equipment

Manufacturer: Olympus Epoch 600
Serial #: 130048505
Cal Due: Jan-20
Transducers: FAST, Pencil, FH2E & 45° & 60° Wedges
Type: Single / Dual
Frequency: 5.0MHz / 15MHz /7.5MHz / 5.0MHz
Serial #: 01C0DL / 875731 / 014523 / 834573
UT Calibration Blocks: FAST /MAB / Mini PACS / EDM Block

Advanced UT Equipment

Manufacturer: Olympus OmniScan
Serial #: QC-012700
Cal Due: Jan-20
Transducers: 10L16 N55S Wedge
Type: Linear Array
Frequency: 10 MHz
Serial #: A92393
Calibration Blocks: MAB / Mini PACS / EDM Block

Magnetic Particle Equipment

Manufacturer: Magnaflux Y-1
Serial #: 3840
Cal Due: Feb-20
Paint: Magnaflux WCP-2
Particles: Tiede 616.1
Colour Black
Suspension: Water

Visual Inspection

Calipers	Rulers	5% Nital	Half Cell	Bridge Bar	Profile Gauge
Dial Gauge	30 m Tape	Multi-Meter	pH Paper	4' Level	White Light

Work Scope:

SCOPE	INSPECTION METHODS										
					ULTRASONIC EXAMINATION						
	VT	MT	ACID ETCH	LASER SCAN	UTT	UTCD	UTLAM	PAUT	TOFD	AUT	FLAW SIZING
100% Exposed Pipe:	VT	MT			8 Points						
Long Seam Welds:	VT	MT									
Girth Welds:	VT	MT									
ILI Targets:											
Corrosion/ML:	VT	MT			UT Pen						
Mechanical Damage:	VT	MT			UT Pen		UTLAM				
Arc Burn Assessment:											
Dent/Deformation:											
SCC:	VT	MT			UT Pen	UTCD	UTLAM	PAUT			PAUT
Grind Repairs General:	VT	MT			UT Pen						
Grind Repairs DF:	VT	MT	ACID ETCH		UT Pen						
Sleeve Landing Areas											
Sleeves - Longitudinal Seams:											
Sleeves - Circumferential Welds:											
Weld Tie In:											
In Service Welding Area:											
Nipple Filled Welds:											

Terms and Conditions

Service Terms and Conditions

The agreement of NDT Group Inc. to perform services extends only to those services provided for in writing. Under no circumstances shall such services extend beyond the performance of the requested services. It is expressly understood that all descriptions comments and expressions of opinion reflect the opinions or observations of NDT Group Inc. based on information and assumptions supplied by the owner/operator and are not intended nor can they be construed as representations or warranties. NDT Group Inc. is not assuming any responsibilities of the owner/operator and the owner/operator retains complete responsibility for the engineering manufacture repair and use decisions as a result of the data or other information provided by NDT Group Inc. In no event shall NDT Group Inc.'s liability in respect of the services referred to herein exceed the amount paid for such services.

Test Methods (NDE and Inspection)

Statements, findings, results and/or reports made or prepared by an employee of NDT Group Inc., including findings about an item meeting or not meeting code, represent the opinion of the employee based on available data at the time of the inspection and shall at all times be subject to inherent limitations of these technologies. NDT Group Inc. cannot be held responsible if employees of Client or another vendor reach different opinions. NDT Group Inc. recommends confirming all such opinions through a second method whenever practicable.

Fitness for Service

Client is responsible for making all repair, recoat, replacement and similar decisions, including decisions based on or regarding inspection/NDE results, remaining strength calculations and Client's procedures for maintenance. Client is responsible for determining the specific remaining strength calculation to be performed (B31G, Modified B31G, RStreng, etc.) and the pipe parameters used for such. NDT Group Inc. cannot be responsible for selecting or making any recommendations regarding the correct calculation method or design factor. When performing calculations, NDT Group Inc's obligation shall be limited to entering data into a calculation and providing the results to Client. NDT Group Inc. does not make any representations regarding the accuracy of the data or the results of the software calculations. Client is responsible for all decisions regarding fitness for service. NDT Group Inc. does not make any representations regarding, and shall not have any liability for, any recommendations, proposed changes, updates and similar statements from NGI's employees regarding Client's in-house integrity programs.

Anomaly Legend

no St Corrosion	GF - Grind Feature	ML - Metal-Loss
D - Dent	ILI - In-Line Inspection	SCC - Stress-Corrosion Cracking
DF - Damage Feature	LI - Linear Indication	

Abbreviations

AUT - Automated Ultrasonic Testing.
AWT - Adjacent UT Wall Thickness
DSAW - Double Submerged Arc Welding
EFW - Electric Flash Weld
ERW - Electric Resistance Weld
FAST UT - Technique for crack detection and sizing.
FCAW - Flux Cored Arc Welding
GMAW - Gas Metal Arc Welding
GTAW - Gas Tungsten Arc Welding
GW - Girth Weld
KPa - Kilopascals
LS - Longitudinal Weld Seam
MOP - Maximum Operating Pressure
MB31.G - Modified B31.G
MT - Magnetic Particle Testing.
MUT - Manual Ultrasonic Testing
NWT - Nominal Wall Thickness
PAUT - Phased Array UT
PSI - Pounds per Square Inch
RPR - Rupture Pressure Ratio
RSTRENG - Remaining Strength Calculation
SAW - Submerged Arc Welding
SCC - Stress-Corrosion Cracking
SMAW - Shielded Metal Arc Welding
ToFD - Time-of-Flight Diffraction
UT - Ultrasonic Testing using contact technique.
UTCD - Ultrasonic crack detection examination
UTLAM - Ultrasonic examination for the detection of internal laminar-type indications.
UTSW - Ultrasonic shear-wave or angle beam examination
UTT - Ultrasonic Thickness Testing
U/S - Upstream
D/S - Downstream

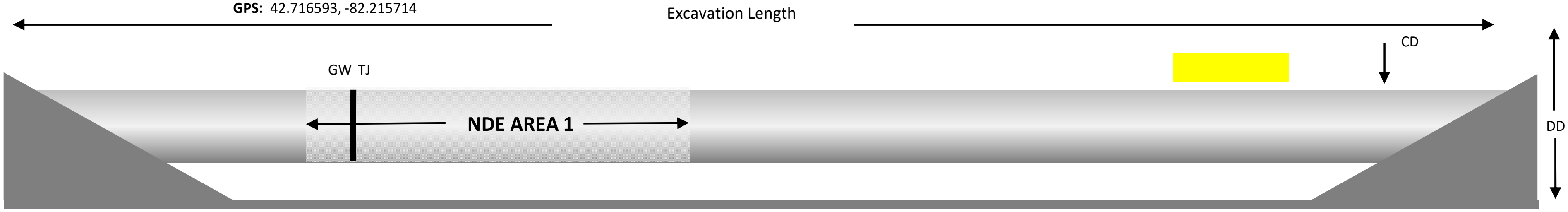
Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 1
Excavation Information

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Flow

GPS: 42.716593, -82.215714



EXCAVATION DETAILS	
Excavation Length:	15.00 m
Excavation Width:	11.00 m
Cover Depth (CD):	1.50 m
Ditch Depth (DD):	3.20 m
Type of Excavation:	Bell
Exposure Start:	**-1.15 m**
Exposure End:	**5.80 m**
Total Exposure:	**6.95 m**
Reference GW:	TJ

NDE AREA 1	
Reference GW:	TJ
NDE Start:	-0.46 m
NDE End:	2.50 m
NDT Area1 Length:	**2.96 m**
Total Exposure Length:	**6.95 m**

NDE AREA 2	
Reference GW:	
NDE Start:	
NDE End:	
NDT Area2 Length:	**0.00 m**
Total NDE Length:	**2.96 m**

Reference GW:	TJ			
Sag?	☐	Yes	☑	No
Overbend?	☐	Yes	☑	No
Sidebend?	☐	Yes	☑	No
# of Joints Exposed:	2			

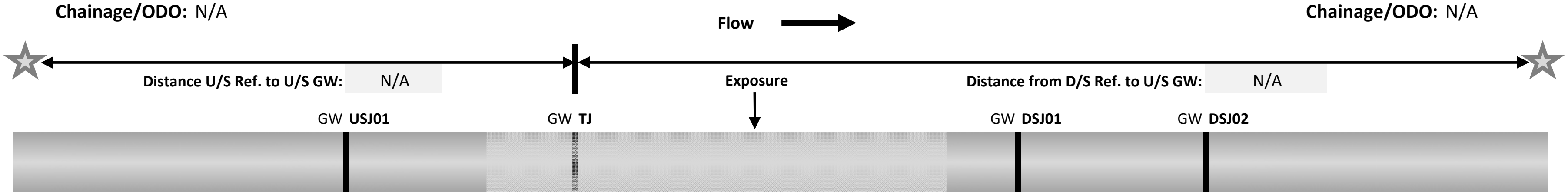
AGM & Site Reference Information
(information provided by client)

Upstream Reference
Reference/AGM: N/A
Chainage/ODO: N/A

Downstream Reference
Reference/AGM: N/A
Chainage/ODO: N/A

Distance U/S Ref. to U/S GW: N/A

Distance from D/S Ref. to U/S GW: N/A

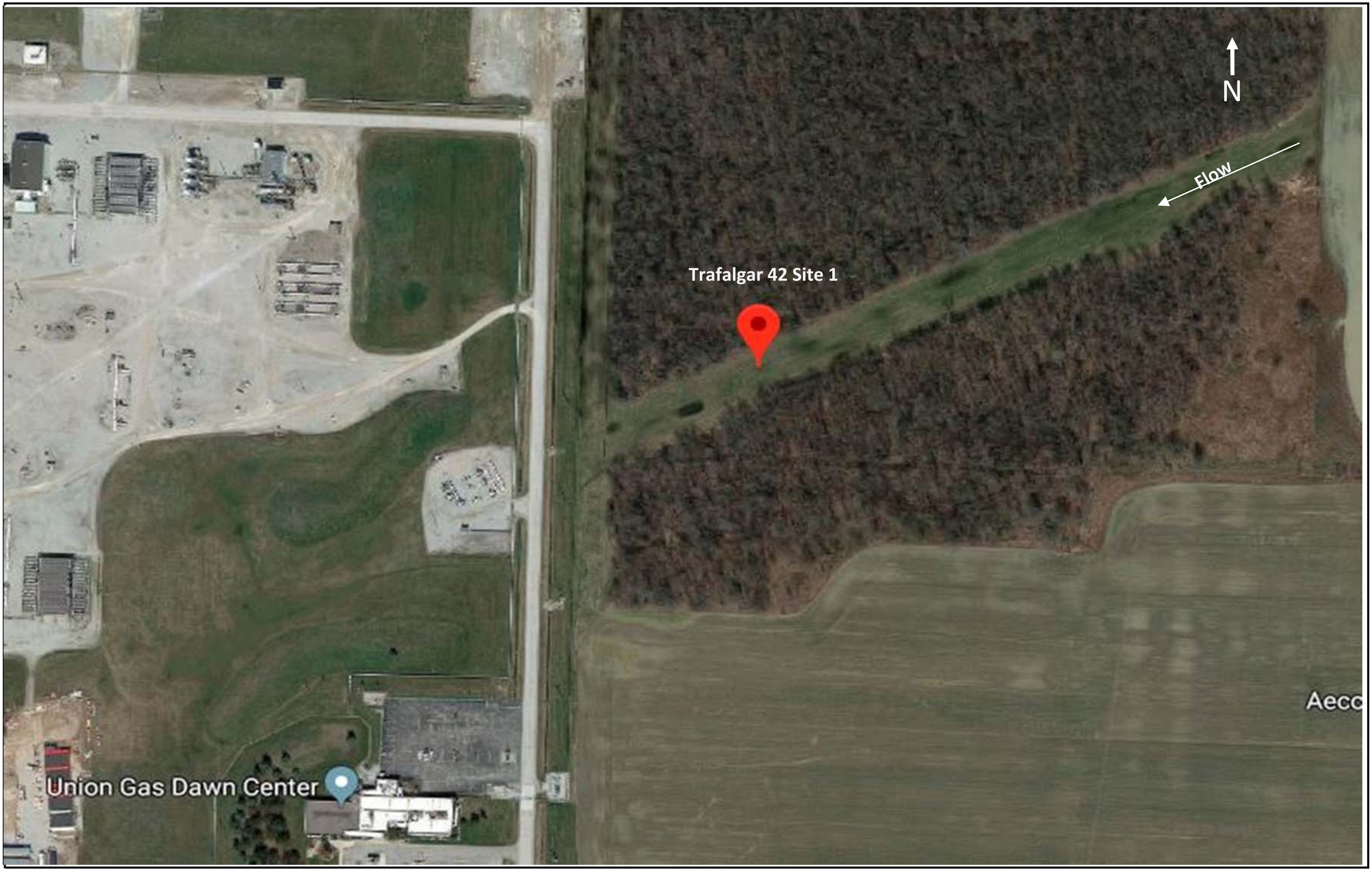


Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 1

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Site Position - Plan View



NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 1

Soils and Topographical Assessment

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Land Use: Grassland
Site Position: Level
Topography: Level

Drainage: Poor
Gleying: Intensely Gleyed (Dark Bluish to Dark Greenish
Parent Material: Lacustrine
Texture: Clay Loam

Max. Slope: 0%
Mottling Ambundance: Common
Size: Medium
Contrast: Distinct

Pipe & Welding Coating Data

Pipe Coating Type: **Polyethylene Tape**
Pipe Coating Type U/S of NDE Area: **Polyethylene Tape**
Weld Coating Type: **Polyethylene Tape**
Pipe Coating Type D/S of NDE Area: **Polyethylene Tape**
Pipe Coating Condition: **Fair**
U/S Pipe Coating Condition: **Fair**
Weld Coating Condition: **Poor**
D/S Pipe Coating Condition: **N/A (Comments)**

Corrosion Deposits

Corrosion Present?
Colour:
Texture:
Magnetic Reaction:
Carbonate Reaction 10%HCL: (10% HCl Reaction)
Samples Taken? No

Sampling & Analysis

Type	Sample #	Location	pH	ORP	10% HCL
Soils	SS-01	Bottom of Pipe			
Ground Water					
Electrolyte					

Sample No.	Analysis Date	Saturation (%)	TDS (mg/L)	Ca (mg/L)	Cl (mg/L)	Mg (mg/L)	K (mg/L)	Na (mg/L)	SO_4^2 (mg/L)	CO_3^{-2} (mg/L)	HCO_3 (mg/L)	Alkalinity (mg/L)	10% HCL Reaction
SS-01													
SS-02													

Soil, Coating, Groundwater, and Environmental Comments:

The excavation was located on level ground in a grass land with forest to the north and south of the excavation. During excavation the side walls consisted of dominantly brown soil consisting primarily of clay loam. Along the bottom of the pipe intensely gleyed soil was found indicative of sitting water and poor drainage. No ground water was noted in the excavation. Electrolytes were identified at CD-06 which had a PH reading between 8 and 9. For details regarding corrosion deposits refer to coating damage page. A soil sample was collected at the bottom of the pipe and will be submitted for analysis if required by Enbridge Gas Engineering.

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line

Investigative Dig Site 1

Coating Assessment

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Coating Feature Number	Type of Damage	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Comments
CD-01	Disbondment	TJ	-450	2550	3000	0	3351	3351	0:00	11:59	0°	360°	Intermittent disbondment noted at seams
CD-02	Tenting	TJ	-450	0	450	370	410	40	1:19	1:28	44°	44°	Tenting along U/S joint DSAW long seam weld
CD-03	Tenting	TJ	0	2550	2550	3180	3220	40	11:23	11:31	346°	346°	Tenting along target joint DSAW long seam weld
CD-04	Wrinkle	TJ	-220	250	470	800	1100	300	2:51	3:56	118°	118°	Wrinkle crossed reference girth weld 3:00 Side
CD-05	Wrinkle	TJ	-30	30	60	2500	3050	550	8:57	10:55	328°	328°	Wrinkle crossed reference girth weld 9:00 Side
CD-06	Wrinkle	TJ	1300	1600	300	2630	3290	660	9:25	11:46	353°	353°	Wrinkle on pipe body

Coating Assessment Comments:

There was a total of 6 Coating Defect Features identified during the coating assessment. CD-01 was intermittent disbondment at the seams of the coating wrap and was present throughout the exposed joint. CD-02 (Upstream Joint) and CD-03 (Target Joint) were identified as tenting on the DSAW long seam welds. CD-04 to CD-06 were significant wrinkles with corrosion deposits underneath. CD-04 and CD-05 interacted with the reference girth weld TJ and were located on the 3:00 and 9:00 sides respectively. CD-06 was wrinkling in the pipe body. Electrolytes were identified at CD-06 which had a PH reading between 8 and 9. General wrinkles on coating were noticed throughout the exposed pipe. Refer to pictures for coating details. Corrosion deposits were noted at these areas of disbondment which consisted of hard white deposits, orange/black deposits and some areas of pasty white deposits. The black/orange corrosion deposits were slightly magnetic, the hard white and pasty white deposits were not. Refer to the close up photos of the corrosion deposits at each coating defect for additional details.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 1

Mechanical Damage Assessment

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Feature Number	Type of Damage	ILI Feature Number	Target Predicted Depth (%)	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Circ Start (°)	Circ End (°)	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	On or Near Weld (within 12.7mm)	MB31.G Burst Pressure (kPa)	Grind Repaired?	Repair Details
DF-01	Scab			TJ	-350	-300	50	963	968	5	3:26	3:27	103°	104°		11.2				No		Yes	Removed
DF-02	Gouge / Scrape			TJ	-252	-236	16	2408	2412	4	8:37	8:38	259°	259°	10.9	11.2	0.3	3%	1.8%	No	10757	Yes	Removed
DF-03	Gouge / Scrape			TJ	-176	-173	3	2317	2347	30	8:17	8:24	249°	252°	10.8	11.2	0.4	4%	2.7%	No	10758	Yes	Removed
DF-04	Gouge / Scrape			TJ	-82	-70	12	2566	2571	5	9:11	9:12	276°	276°	10.9	11.2	0.3	3%	1.8%	No	10757	Yes	Removed
DF-05	Gouge / Scrape			TJ	-64	-62	2	440	474	34	1:34	1:41	47°	51°	11.0	11.2	0.2	2%	0.9%	No	10758	Yes	Removed
DF-06	Gouge / Scrape			TJ	-62	-42	20	520	563	43	1:51	2:00	56°	60°	10.9	11.2	0.3	3%	1.8%	No	10756	Yes	Removed
DF-07	Scab			TJ	-30	-12	18	1450	1455	5	5:11	5:12	156°	156°		11.2				Yes		Yes	Removed
DF-08	Gouge / Scrape			TJ	25	38	13	2777	2790	13	9:56	9:59	298°	300°	10.9	11.2	0.3	3%	1.8%	No	10757	Yes	Removed
DF-09	Gouge / Scrape			TJ	63	66	3	2890	2922	32	10:20	10:27	310°	314°	11.0	11.2	0.2	2%	0.9%	No	10758	Yes	Removed
DF-10	Scab			TJ	71	316	245	2863	2883	20	10:15	10:19	308°	310°		11.2				No		Yes	Removed
DF-11	Gouge / Scrape			TJ	216	223	7	84	155	71	0:18	0:33	9°	17°	10.8	11.2	0.4	4%	2.7%	No	10757	Yes	Removed
DF-12	Scab			TJ	234	259	25	2105	2109	4	7:32	7:33	226°	227°		11.2				No		Yes	Removed
DF-13	Scab			TJ	387	432	45	2100	2103	3	7:31	7:31	226°	226°		11.2				No		Yes	Removed
DF-14	Scab			TJ	407	452	45	2790	2796	6	9:59	10:00	300°	300°		11.2				No		Yes	Removed
DF-15	Scab			TJ	502	527	25	2185	2188	3	7:49	7:50	235°	235°		11.2				No		Yes	Removed
DF-16	Scab			TJ	875	1075	200	2773	2798	25	9:55	10:01	298°	301°		11.2				No		Yes	Removed
DF-17	Scab			TJ	1045	1073	28	325	329	4	1:09	1:10	35°	35°		11.2				No		Yes	Removed
DF-18	Gouge / Scrape			TJ	1620	1635	15	2240	2290	50	8:01	8:11	241°	246°		11.2				No		Yes	Removed
DF-19	Scab			TJ	1629	1659	30	2437	2440	3	8:43	8:44	262°	262°		11.2				No		Yes	Removed
DF-20	Scab			TJ	2166	2199	33	3060	3064	4	10:57	10:58	329°	329°		11.2				No		Yes	Removed

* AWT - Actual UT Wall Thickness, Replac. - Replacement, P. - Partially, P. Sleev/Remov - Partially Sleeved & Partially Removed

Mechanical Damage Comments:

There was a total of 20 damage features noted in the NDE assessment area consisting of 9 gouge/scrape features and 11 scab-like features. DF-07 is considered to be interacting with the reference girth weld GW TJ due to interaction rules, however the feature is approximately 7mm from the girth weld. No grind remediation has been performed to date. All damage features were successfully removed as per the Enbridge Gas Engineering remediation report for this site. No further repairs were required, site to be recoated.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line

Investigative Dig Site 1

Stress-Corrosion Cracking Assessment

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Feature Number	Associated Features	ILI Feature Number	Target Predicted Depth (%)	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Axial Interaction?	Circ. Interaction?	Average Crack Length(mm)	Adjacent UT Wall Thickness (mm)	Max Length (mm)	Crack-Max Depth (mm)	* Crack-Max Depth (%)	URL (mm)	CEPA Category	Repair Details
SCC-01				TJ	337	352	15	2403	2416	13	8:36	8:39	258°	260°	No	No	2.0	11.2	2.0	0.2	2%	11.0		Removed
SCC-02				TJ	535	543	8	1976	1981	5	7:04	7:05	212°	213°	No	No	2.0	11.2	2.0	0.2	2%	11.0		Removed
SCC-03				TJ	2190	2224	34	1455	1482	27	5:12	5:18	156°	159°	No	No	2.0	11.2	4.0	0.2	2%	11.0		Removed

* AWT - Actual UT Wall Thickness, URL - Unaffected Remaining Ligament, P. - Partially, P. Sleev/Remov - Partially Sleeved & Partially Removed

SCC Assessment Comments:

There was a total of 3 SCC features. The longest SCC colony was SCC-03 with a length of 34mm, and longest interacting crack length of 4mm. SCC-01 and SCC-02 showed no axial or circumferential crack interaction so the average crack length is also the longest crack length (2mm). No depth sizing was possible on the SCC features which indicates the features are likely less than 10%NWT. No grind remediation has been attempted to date. All SCC features were successfully removed by grind remediation as per the Enbridge Gas Engineering repair recommendation for this site. All features had maximum crack depths of 0.2mm. No further repairs were required, site to be recoated.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line

Investigative Dig Site 1

Grind Repair Assessment

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Feature Number	Repaired Features	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	Grind Repaired?	MB31.G Burst Pressure (kPa)	Repair Details
GF-01	DF-01	TJ	-360	-298	62	955	980	25	3:25	3:30	103°	105°	11.0	11.2	0.2	2%	0.9%	Yes	10750	Recoat
GF-02	DF-02	TJ	-265	-225	40	2398	2423	25	8:35	8:40	258°	260°	10.8	11.2	0.4	4%	2.7%	Yes	10748	Recoat
GF-03	DF-03	TJ	-190	-164	26	2312	2357	45	8:16	8:26	248°	253°	10.6	11.2	0.6	5%	4.5%	Yes	10750	Recoat
GF-04	DF-04	TJ	-90	-64	26	2562	2587	25	9:10	9:15	275°	278°	10.8	11.2	0.4	4%	2.7%	Yes	10753	Recoat
GF-05	DF-05	TJ	-70	-53	17	438	476	38	1:34	1:42	47°	51°	10.9	11.2	0.3	3%	1.8%	Yes	10756	Recoat
GF-06	DF-06	TJ	-73	-33	40	508	564	56	1:49	2:01	55°	61°	10.8	11.2	0.4	4%	2.7%	Yes	10748	Recoat
GF-07	DF-07	TJ	-41	-9	32	1440	1472	32	5:09	5:16	155°	158°	10.9	11.2	0.3	3%	1.8%	Yes	10753	Recoat
GF-08	DF-08	TJ	22	39	17	2768	2793	25	9:54	10:00	297°	300°	11.0	11.2	0.2	2%	0.9%	Yes	10757	Recoat
GF-09	DF-09	TJ	50	75	25	2887	2932	45	10:20	10:29	310°	315°	11.0	11.2	0.2	2%	0.9%	Yes	10756	Recoat
GF-10	DF-10	TJ	68	323	255	2860	2890	30	10:14	10:20	307°	310°	10.9	11.2	0.3	3%	1.8%	Yes	10671	Recoat
GF-11	DF-11	TJ	205	231	26	79	161	82	0:16	0:34	8°	17°	10.6	11.2	0.6	5%	4.5%	Yes	10750	Recoat
GF-12	DF-12	TJ	232	264	32	2092	2124	32	7:29	7:36	225°	228°	11.1	11.2	0.1	1%	0.0%	Yes	10758	Recoat
GF-13	DF-13	TJ	366	476	110	2094	2131	37	7:29	7:37	225°	229°	10.9	11.2	0.3	3%	1.8%	Yes	10721	Recoat
GF-14	DF-14	TJ	402	464	62	2782	2809	27	9:57	10:03	299°	302°	10.8	11.2	0.4	4%	2.7%	Yes	10735	Recoat
GF-15	DF-15	TJ	494	552	58	2180	2200	20	7:48	7:52	234°	236°	11.0	11.2	0.2	2%	0.9%	Yes	10751	Recoat
GF-16	DF-16	TJ	872	1097	225	2771	2811	40	9:55	10:03	298°	302°	11.0	11.2	0.2	2%	0.9%	Yes	10718	Recoat
GF-17	DF-17	TJ	1030	1113	83	316	358	42	1:07	1:16	34°	38°	10.9	11.2	0.3	3%	1.8%	Yes	10734	Recoat
GF-18	DF-18	TJ	1618	1658	40	2232	2304	72	7:59	8:14	240°	247°	10.7	11.2	0.5	4%	3.6%	Yes	10744	Recoat
GF-19	DF-19	TJ	1620	1688	68	2430	2461	31	8:42	8:48	261°	264°	11.0	11.2	0.2	2%	0.9%	Yes	10749	Recoat
GF-20	DF-20	TJ	2158	2218	60	3050	3081	31	10:55	11:01	328°	331°	11.0	11.2	0.2	2%	0.9%	Yes	10751	Recoat

* AWT - Actual UT Wall Thickness, NWT - Nominal Wall Thickness, P. - Partially

Interaction Rules: **6T**

Grind Assessment Comments:

23 grind repairs were required to repair features as outlined in the EGI Remediation report for this site. All features were successfully removed within the requirements as outlined in the remediation report. All grind repairs were found acceptable by Enbridge Engineering, site to be recoated.

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 1
Grind Repair Assessment

Client: Enbridge Gas Inc.
Date: September 3, 2019
Girth Weld: TJ

Feature Number	Repaired Features	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	Grind Repaired?	MB31.G Burst Pressure (kPa)	Repair Details
GF-21	SCC-01	TJ	324	364	40	2400	2425	25	8:35	8:40	258°	260°	11.0	11.2	0.2	2%	0.9%	Yes	10754	Recoat
GF-22	SCC-02	TJ	525	553	28	1972	1992	20	7:03	7:07	212°	214°	11.0	11.2	0.2	2%	0.9%	Yes	10756	Recoat
GF-23	SCC-03	TJ	2180	2232	52	1440	1516	76	5:09	5:25	155°	163°	11.0	11.2	0.2	2%	0.9%	Yes	10752	Recoat

* AWT - Actual UT Wall Thickness, NWT - Nominal Wall Thickness, P. - Partially

Interaction Rules: **6T**

Grind Assessment Comments:

Refer to comments on first grind page.

ENBRIDGE GAS INC. - TRAFALGAR NPS42

001 - SITE OVERVIEW LOOKING DOWNSTREAM

002 - SITE OVERVIEW LOOKING UPSTREAM

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42


003 - SITE OVERVIEW LOOKING NORTH


004 - SITE OVERVIEW LOOKING SOUTH

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

005 - SPOIL PILE

006 - BROWN SOIL DOMINATES ON SIDE WALLS OF EXCAVATION

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

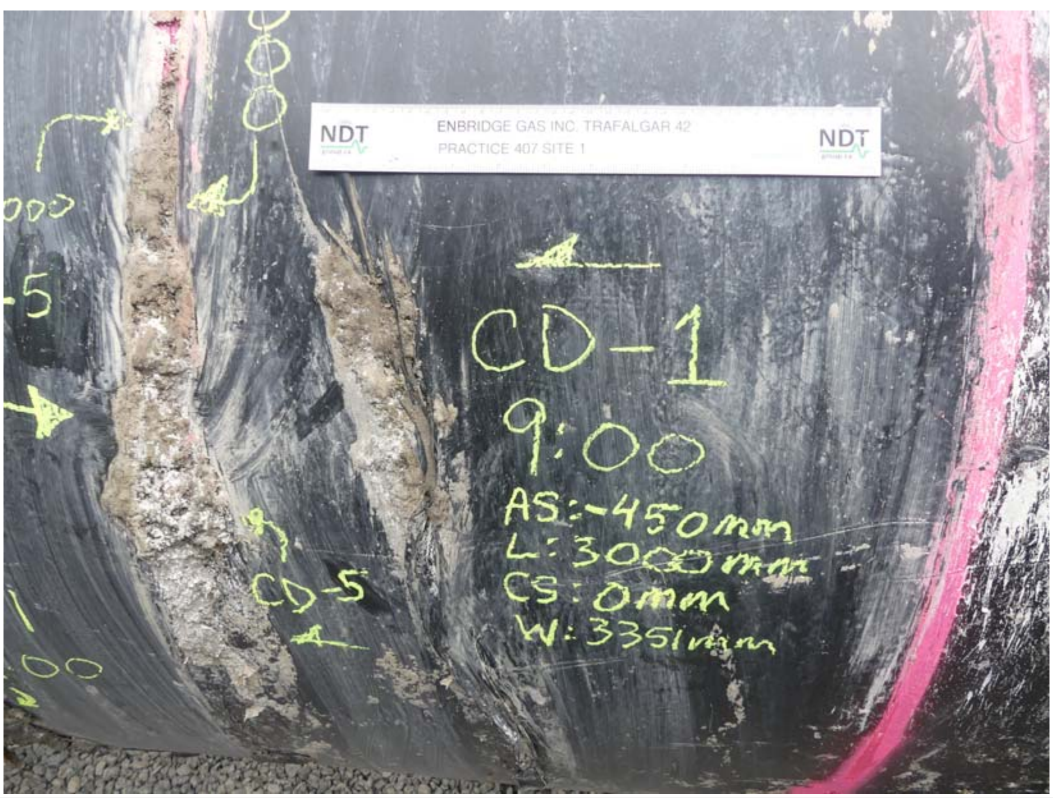
007 - STRONG GLEYING WAS FOUND AT BOTTOM OF PIPE

008 - COATING ASSESSMENT AREA 3 O'CLOCK SIDE

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

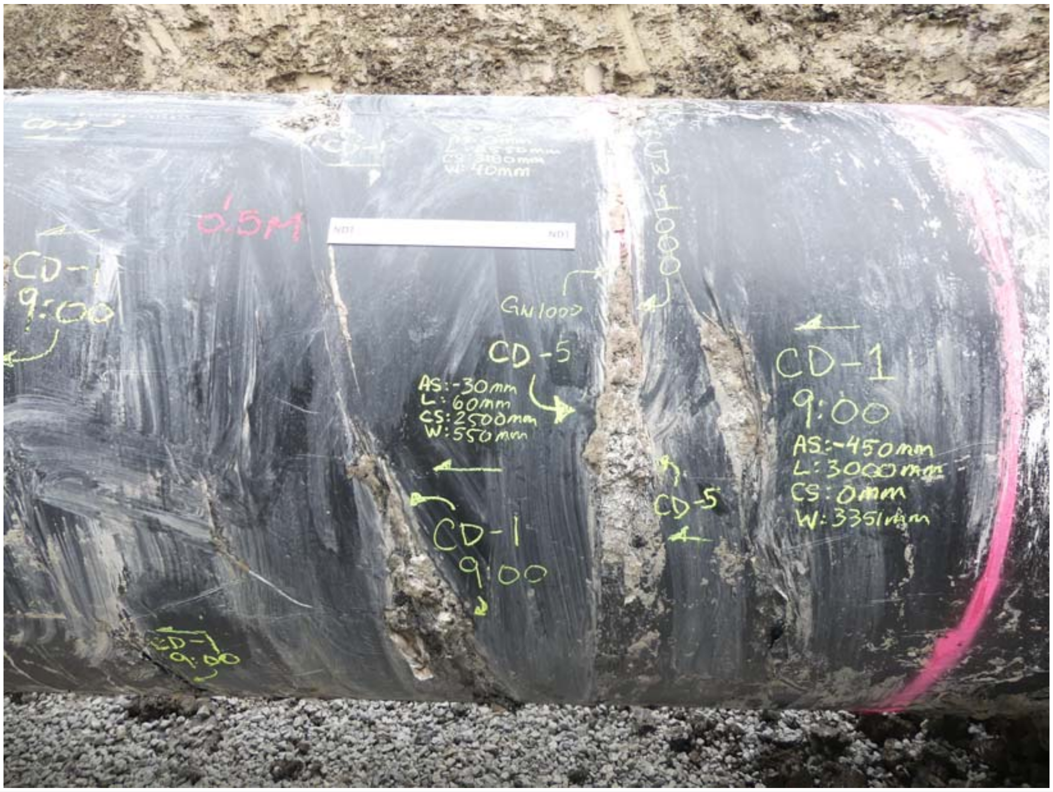
ENBRIDGE GAS INC. - TRAFALGAR NPS42

009 - COATING ASSESSMENT AREA 9 O'CLOCK SIDE



010 - CD-01 (1)

ENBRIDGE GAS INC. - TRAFALGAR NPS42



011 - CD-01 (2), CD-05

012 - CD-01 (3)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

013 - CD-01 (4)

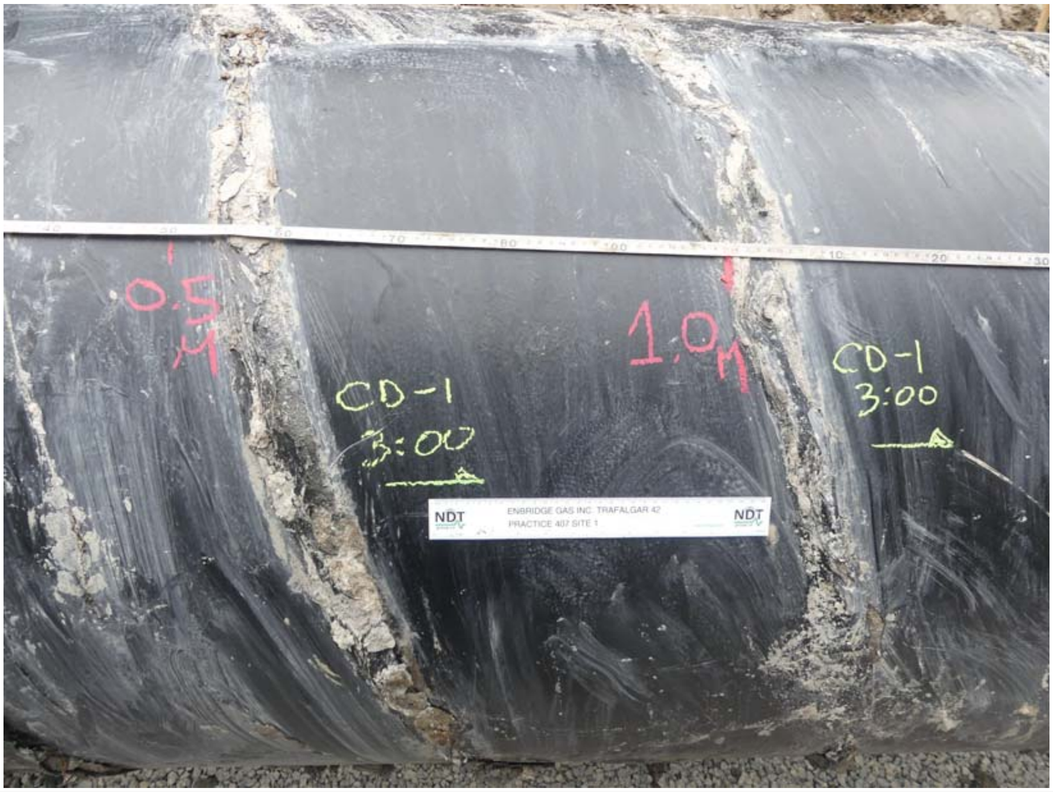
014 - CD-01 (5)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

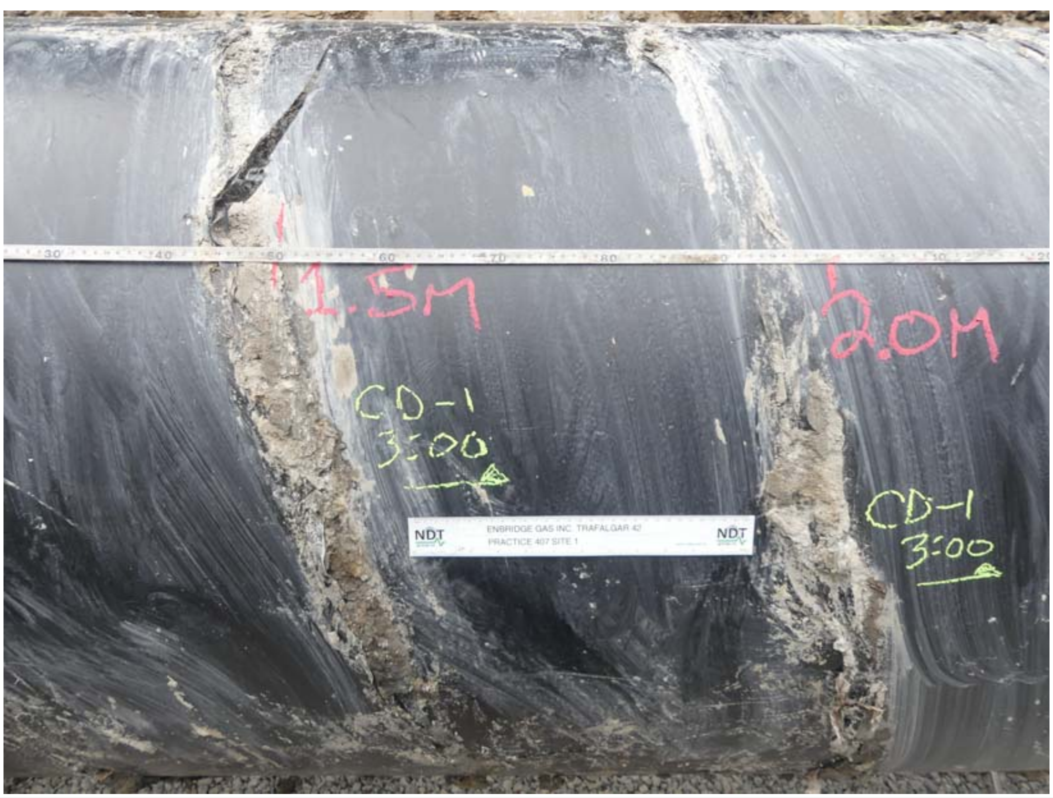
015 - CD-01 (6)

016 - CD-01 (7)

ENBRIDGE GAS INC. - TRAFALGAR NPS42



017 - CD-01 (8)



018 - CD-01 (9)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

019 - CD-01 (10)

020 - CD-01 CLOSE UP

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

021 - CD-01 COATING REMOVED, CLOSE UP OF CORROSION DEPOSIT

022 - CD-01 COATING REMOVED, WHITE HARD CORROSION DEPOSIT

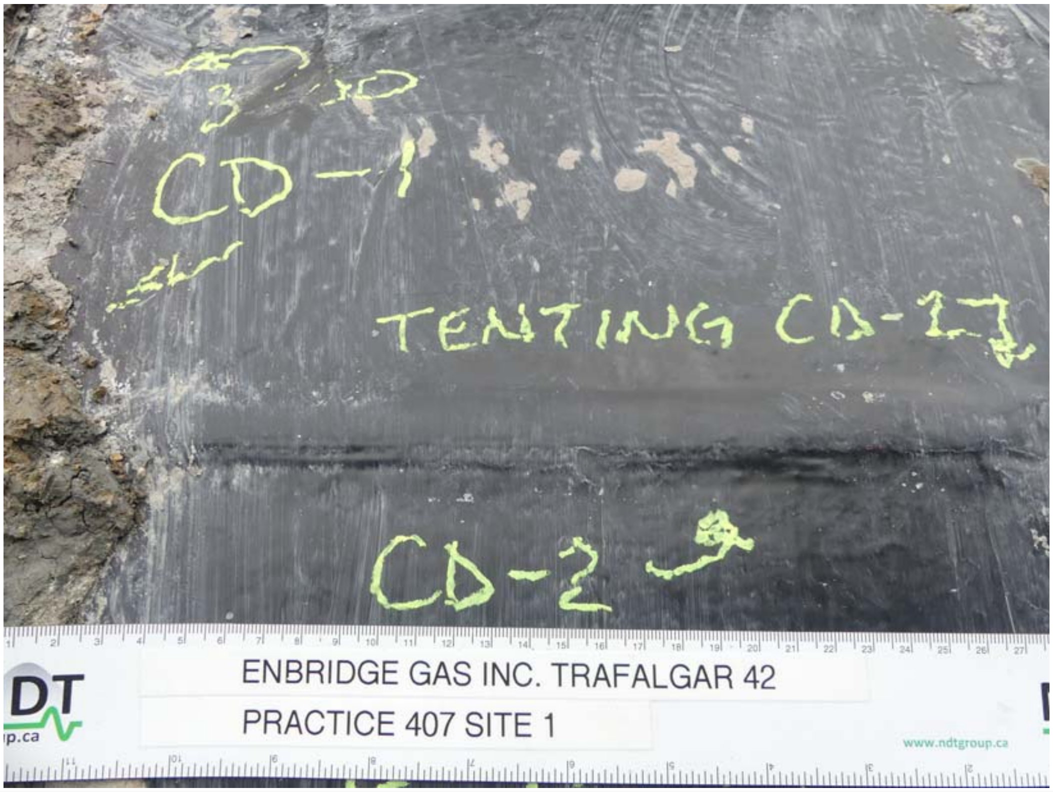
NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42

023 - CD-01 COATING REMOVED, WHITE HARD CORROSION DEPOSIT (2)

024 - CD-02

ENBRIDGE GAS INC. - TRAFALGAR NPS42

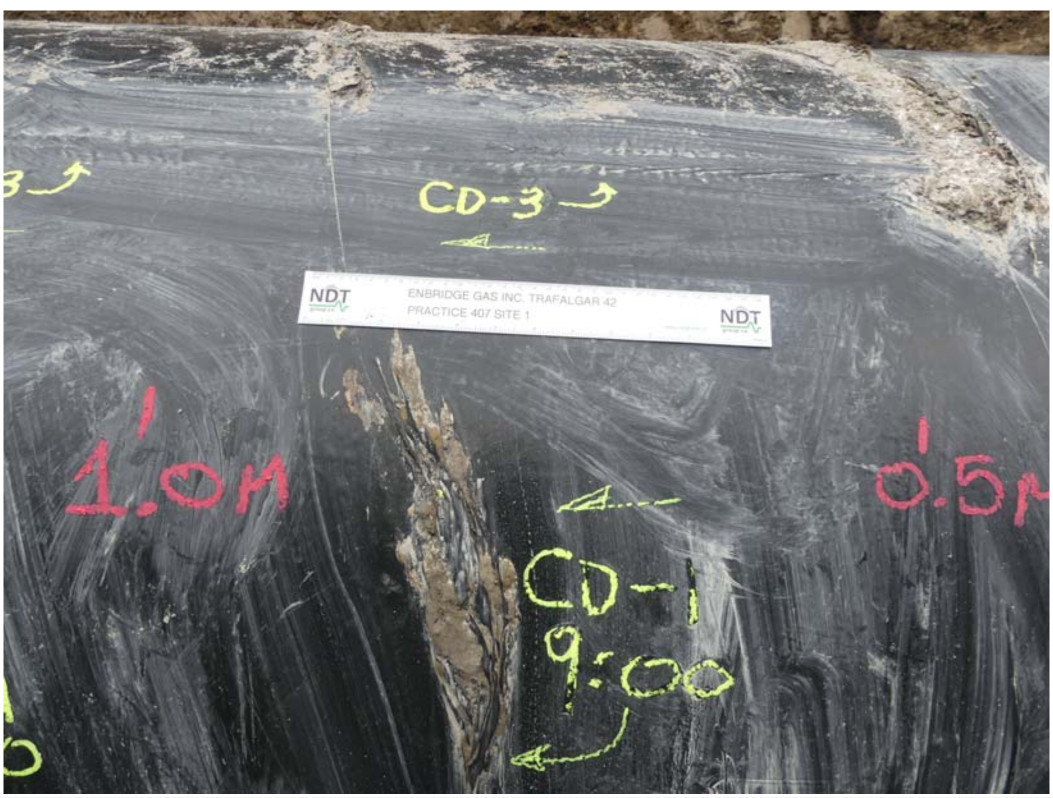


025 - CD-02 CLOSE UP

026 - CD-02 COATING REMOVED, BLACK AND ORANGE CORROSION DEPOSITS

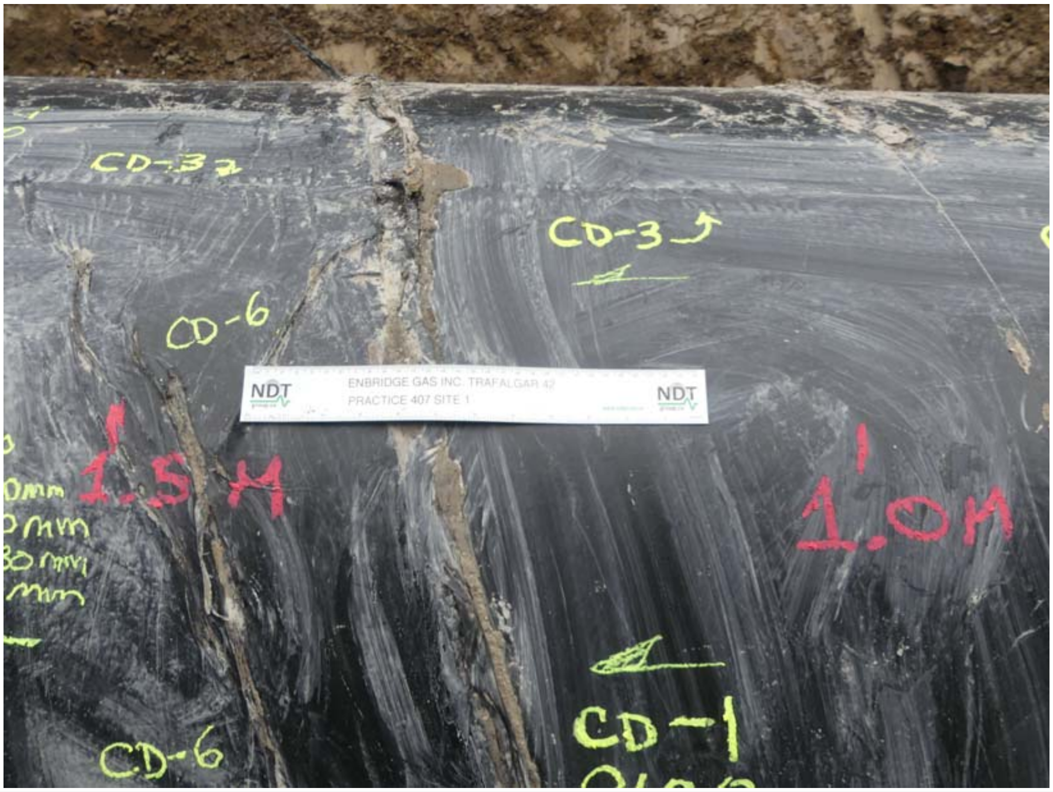
ENBRIDGE GAS INC. - TRAFALGAR NPS42

027 - CD-03 (1)

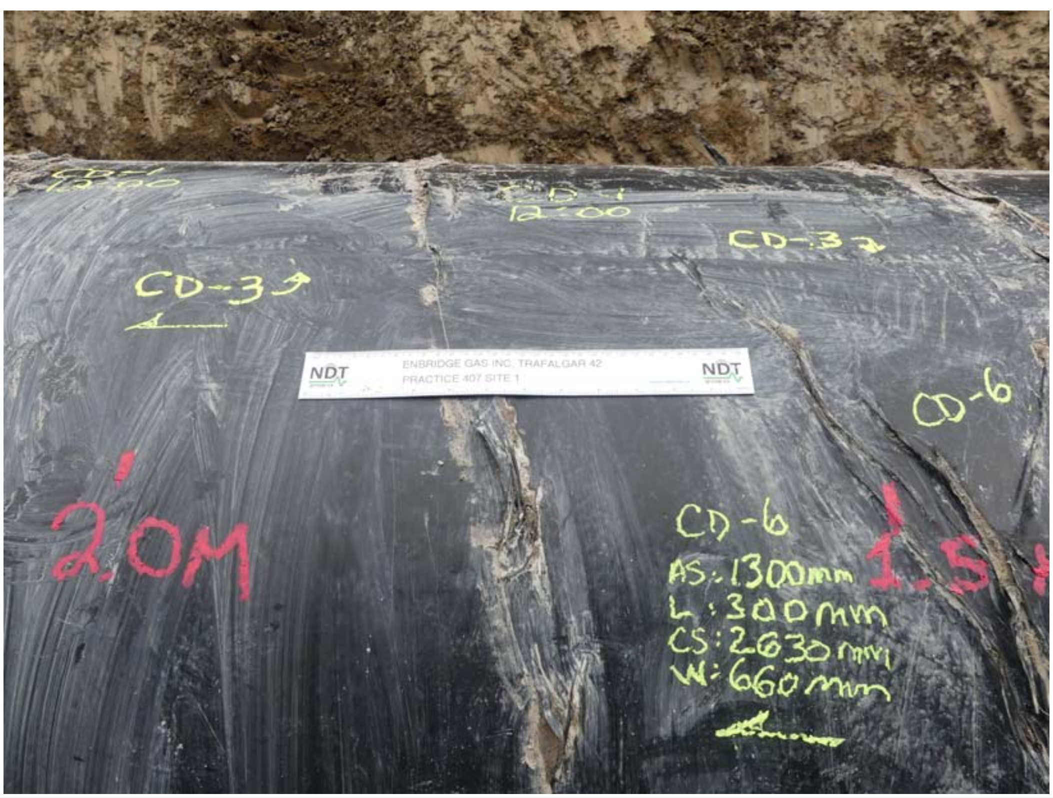


028 - CD-03 (2)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

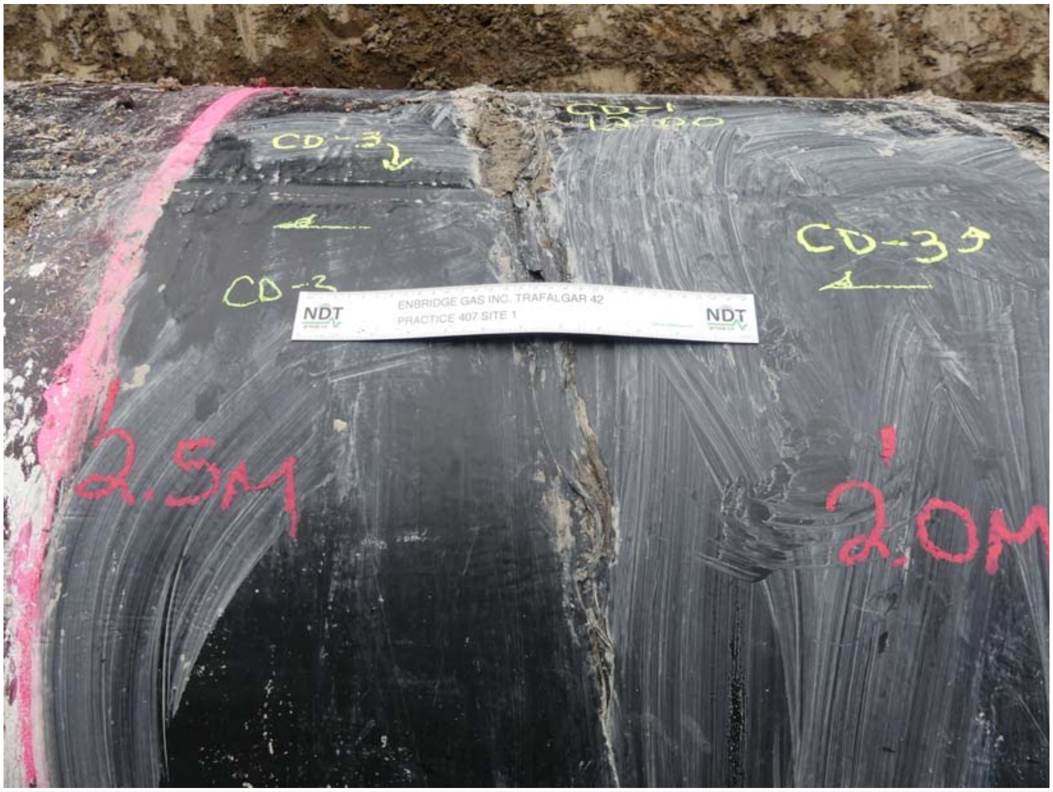


029 - CD-03 (3)



030 - CD-03 (4)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

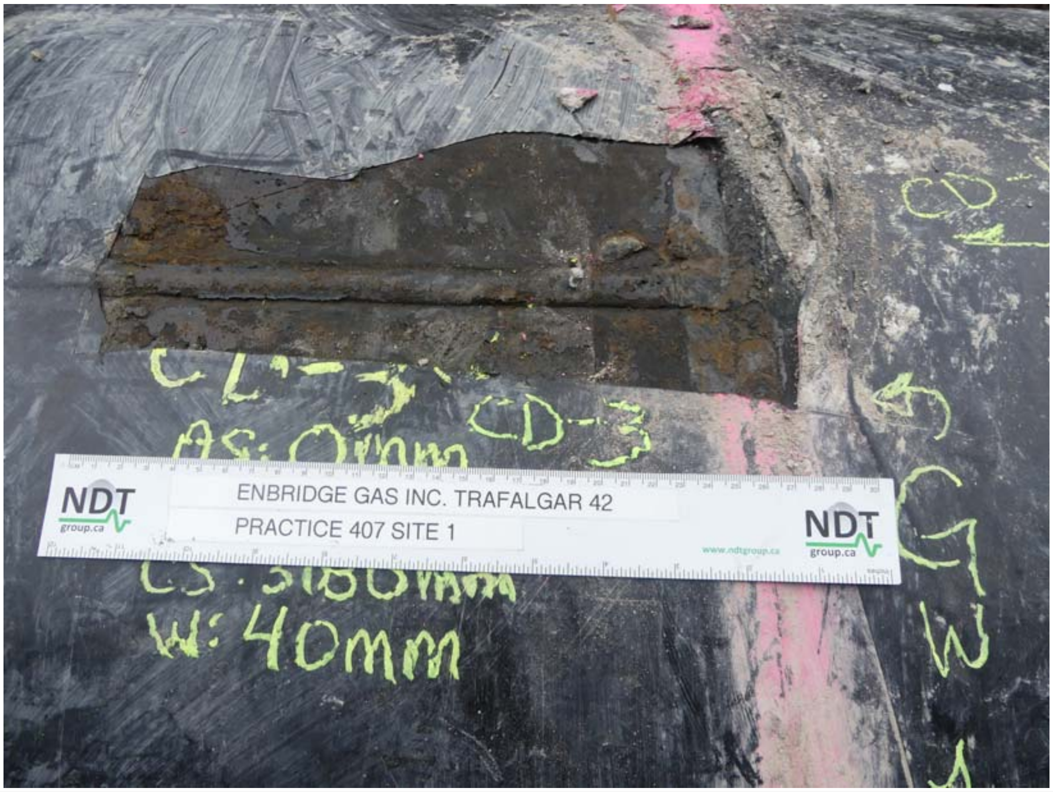


031 - CD-03 (5)

032 - CD-03 TENTING ALONG LONG SEAM CLOSE UP

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

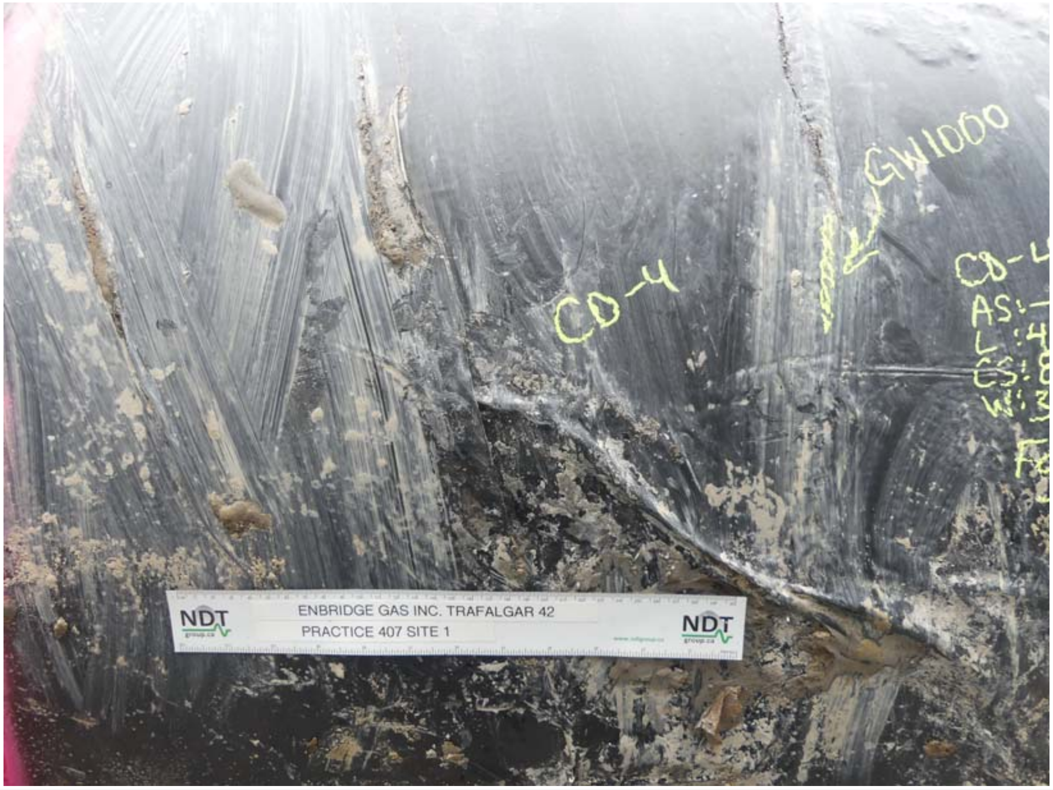
ENBRIDGE GAS INC. - TRAFALGAR NPS42



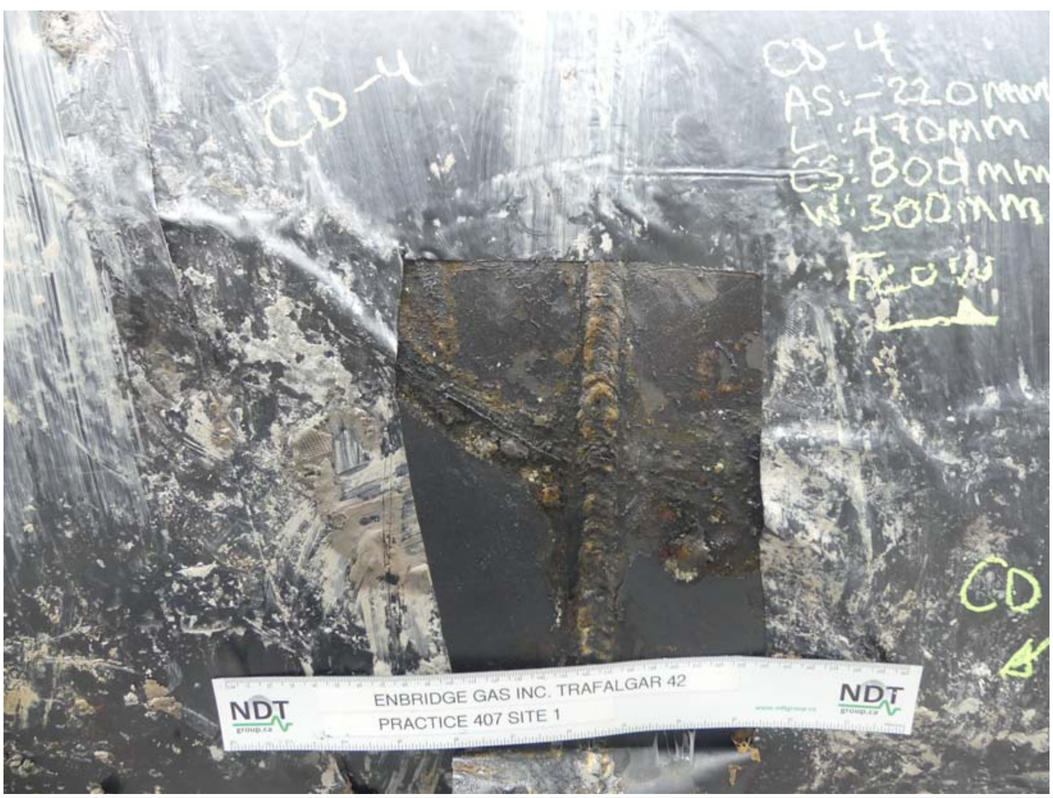
033 - CD-3 COATING REMOVED, BLACK, ORANGE COATING DEPOSITS

034 - CD-04

ENBRIDGE GAS INC. - TRAFALGAR NPS42

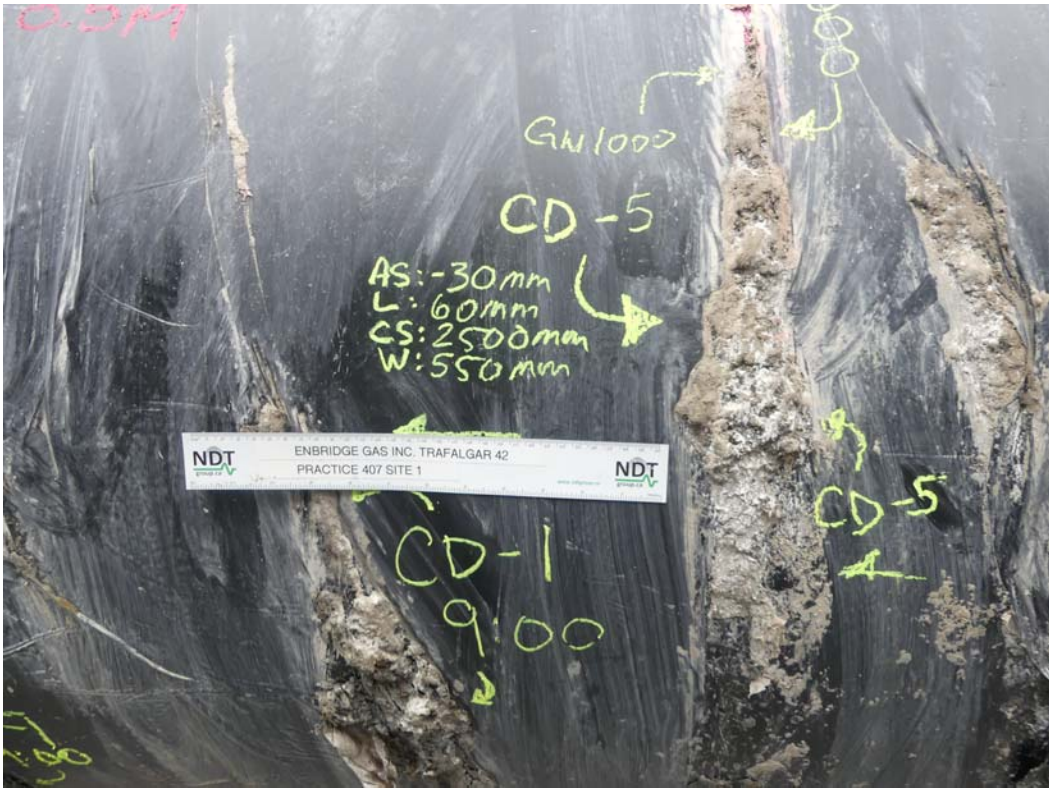


035 - CD-04 CLOSE UP



036 - CD-04 COATING REMOVED, BLACK, ORANGE CORROSION DEPOSITS

ENBRIDGE GAS INC. - TRAFALGAR NPS42

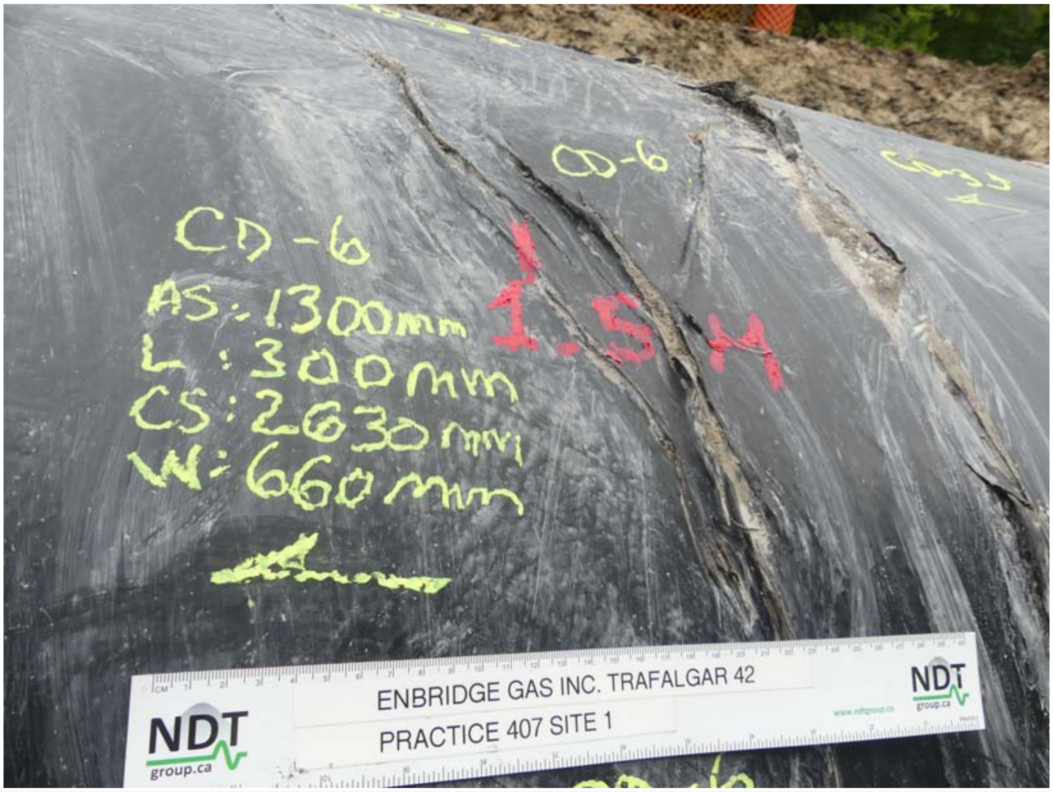


037 - CD-05

038 - CD-05 COATING REMOVED, BLACK AND WHITE CORROSION DEPOSITS

ENBRIDGE GAS INC. - TRAFALGAR NPS42

039 - CD-06



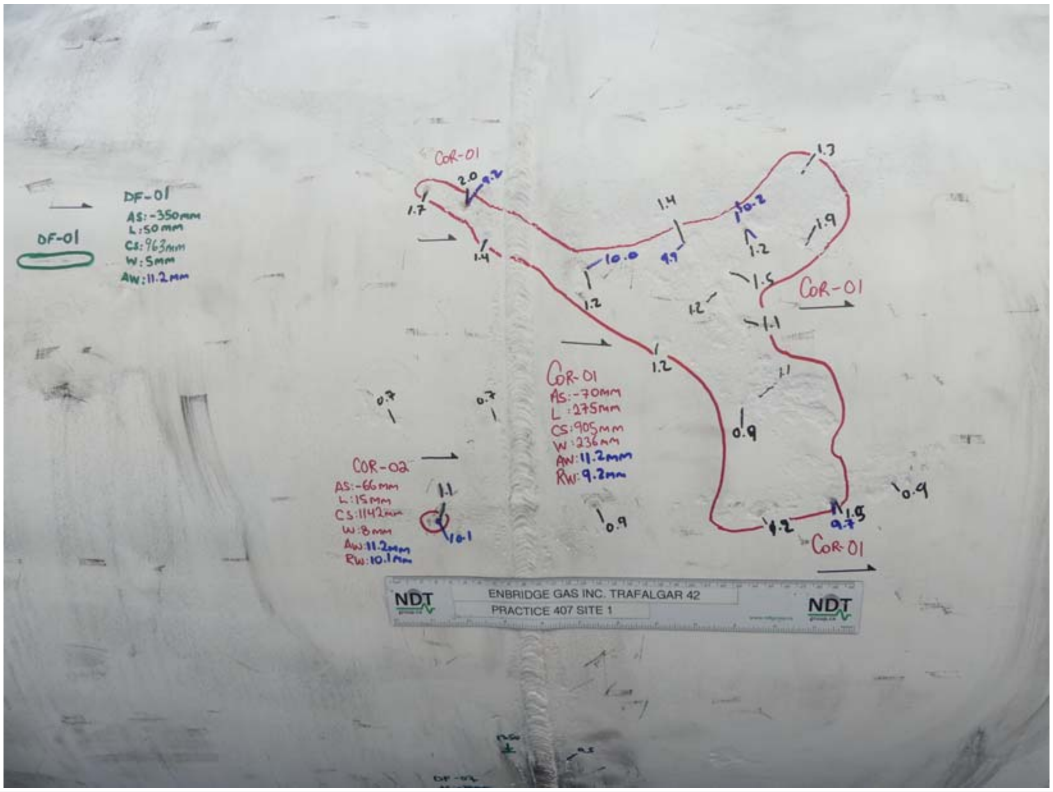
040 - CD-06 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

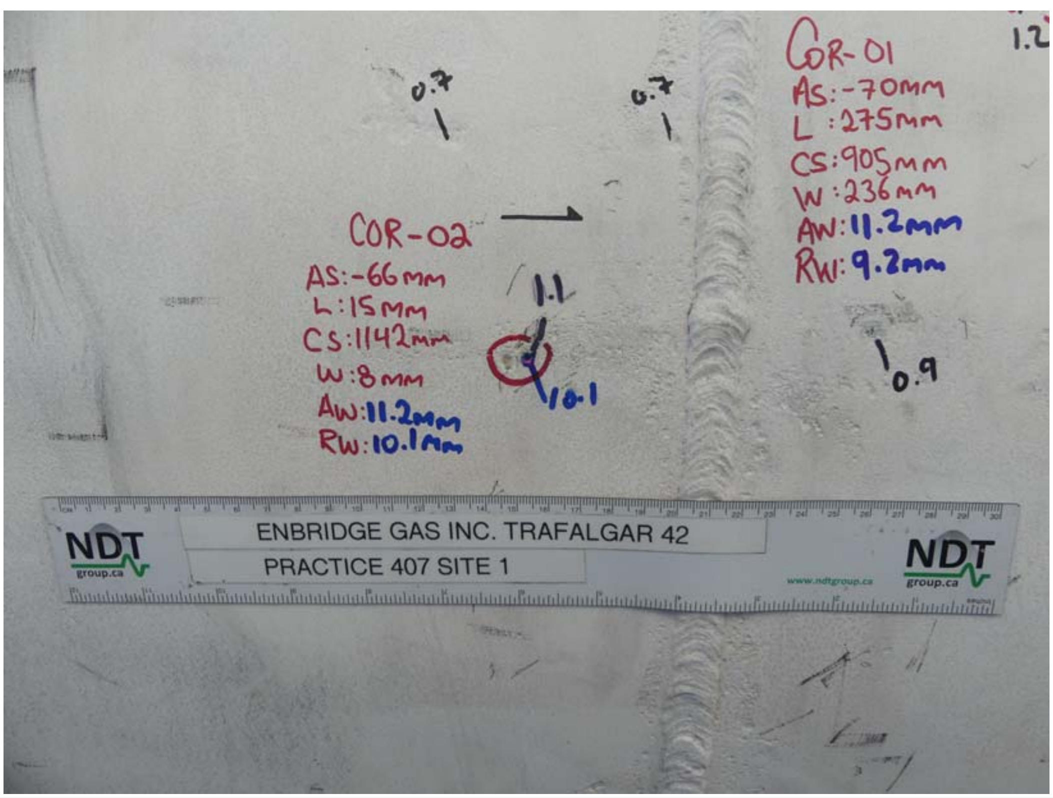
041 - CD-06 COATING REMOVED, ELECTROLYTE PH TAKEN

042 - CD-6 ELECTROLYTES UNDER COATING, MOSTLY NEUTRAL

ENBRIDGE GAS INC. - TRAFALGAR NPS42

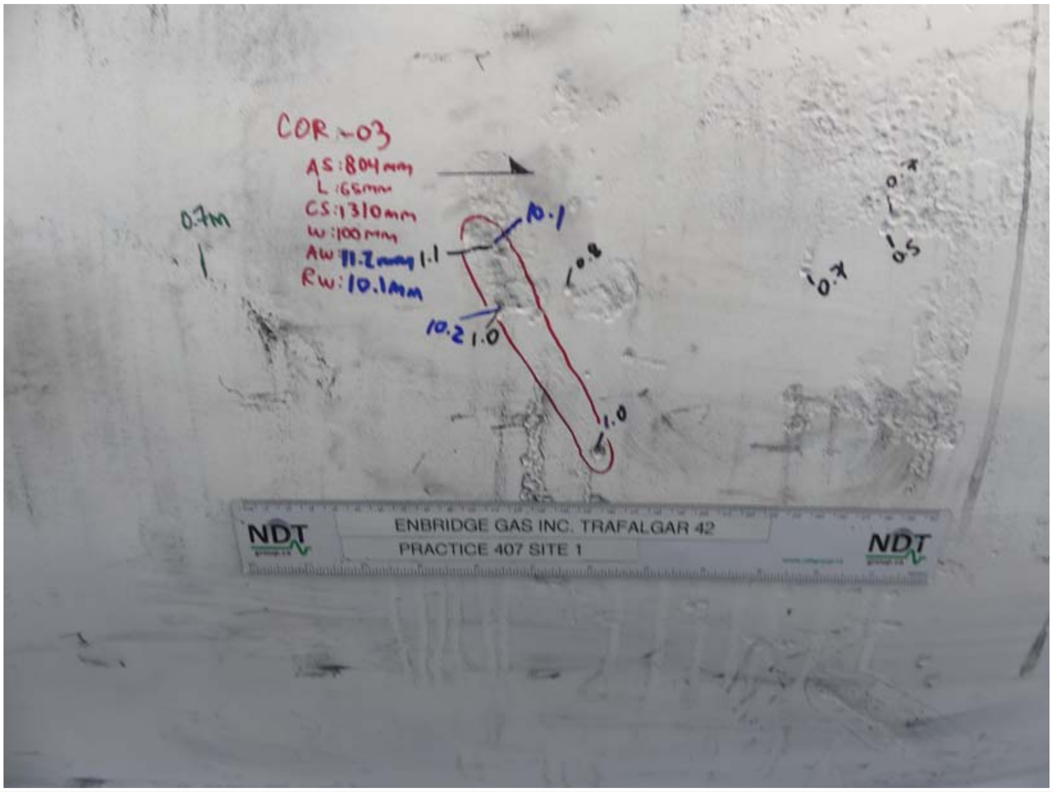


043 - COR-01

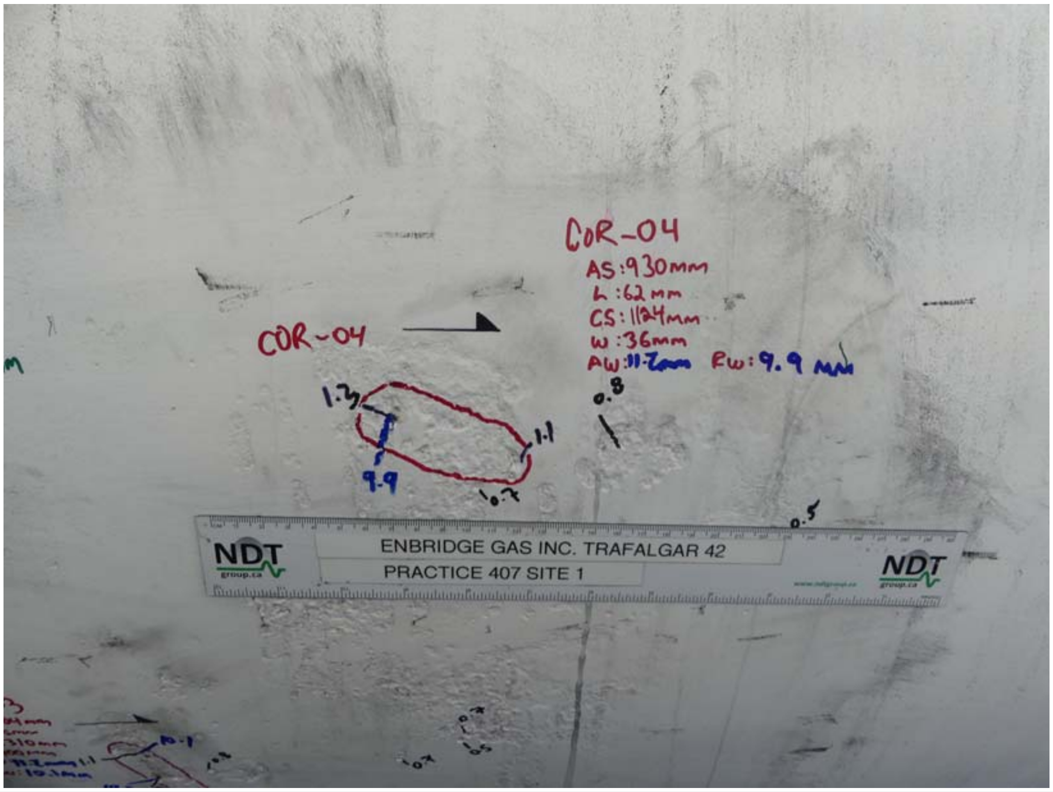


044 - COR-02

ENBRIDGE GAS INC. - TRAFALGAR NPS42

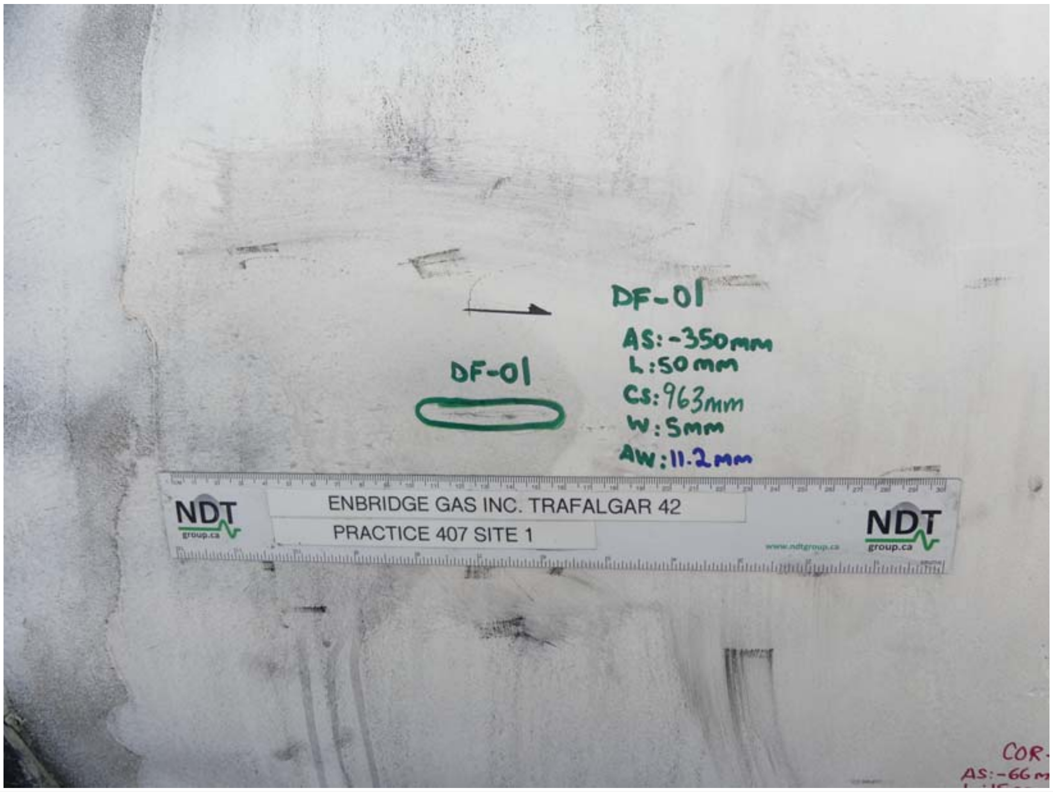


045 - COR-03



046 - COR-04

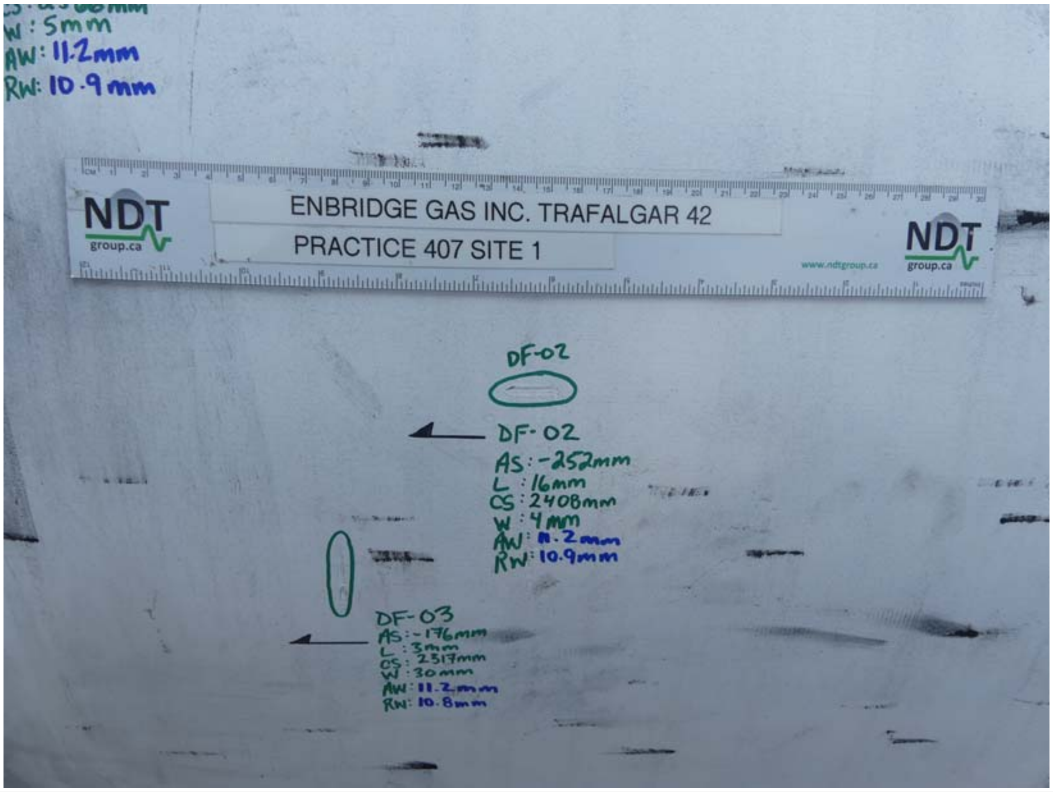
ENBRIDGE GAS INC. - TRAFALGAR NPS42



047 - DF-01

048 - DF-01 CLOSE UP

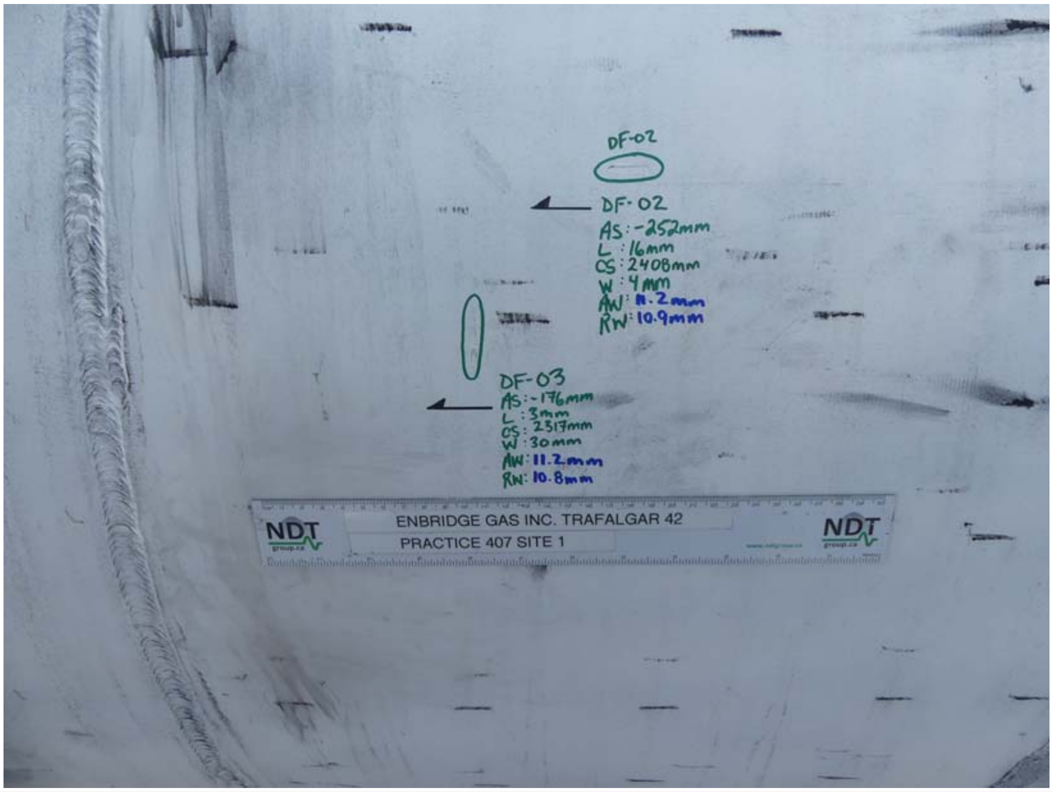
ENBRIDGE GAS INC. - TRAFALGAR NPS42



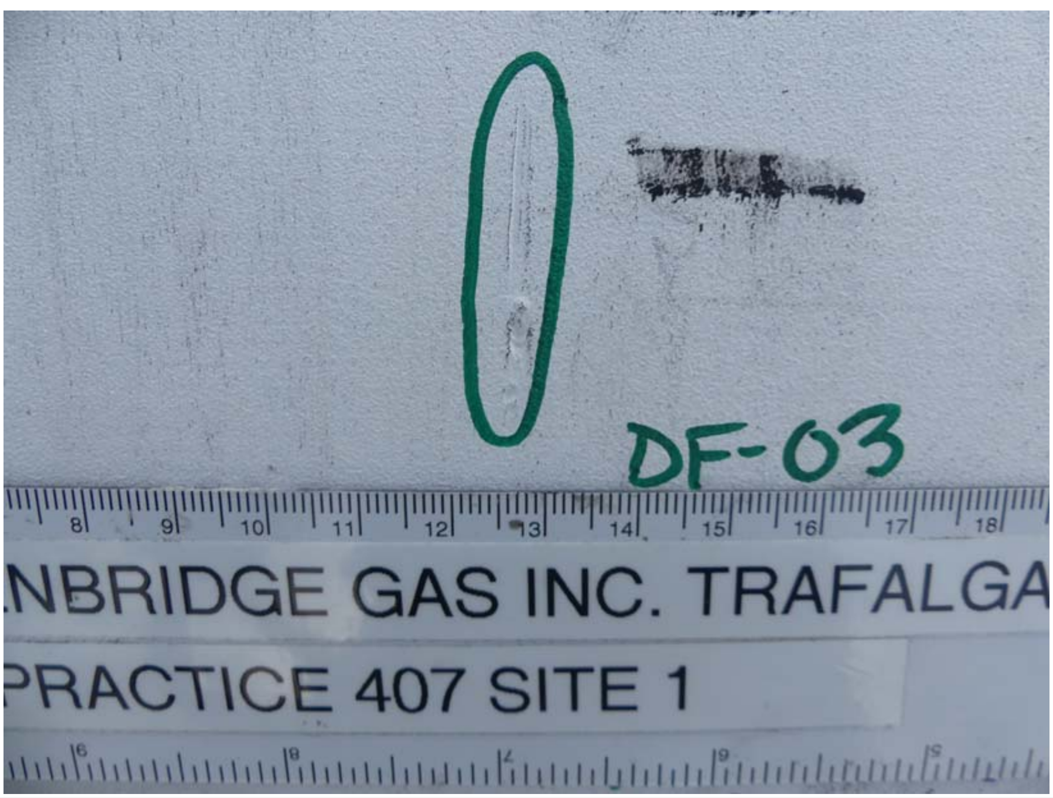
049 - DF-02

050 - DF-02 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

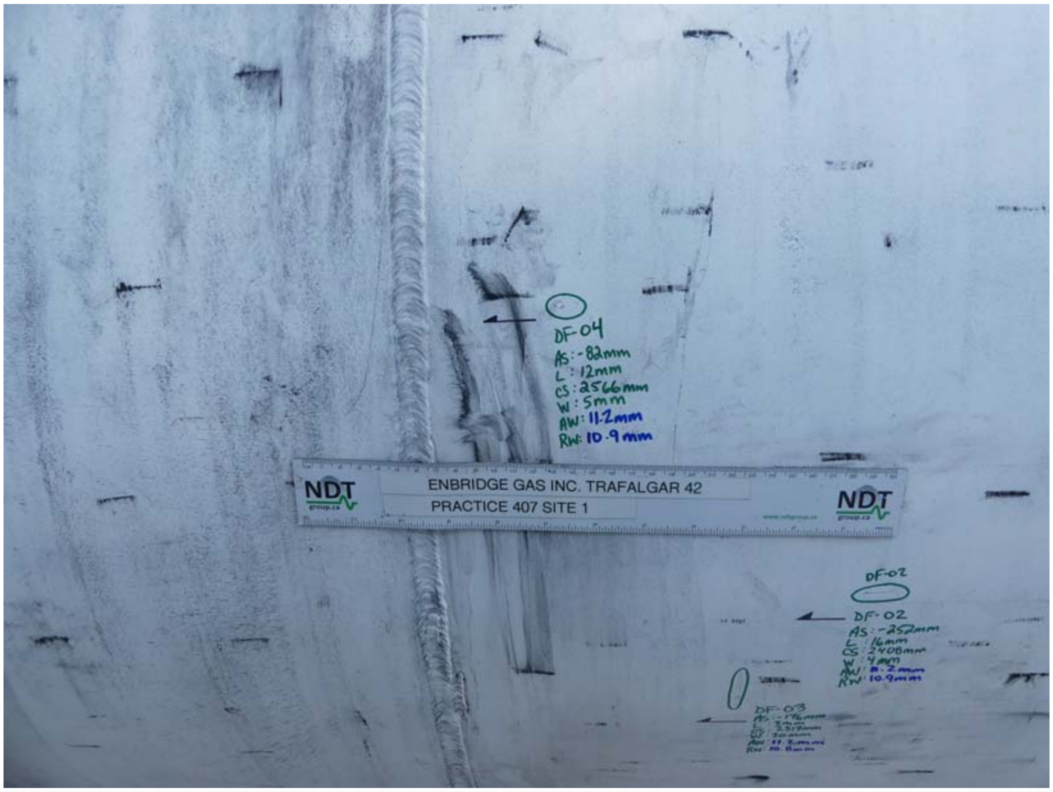


051 - DF-03

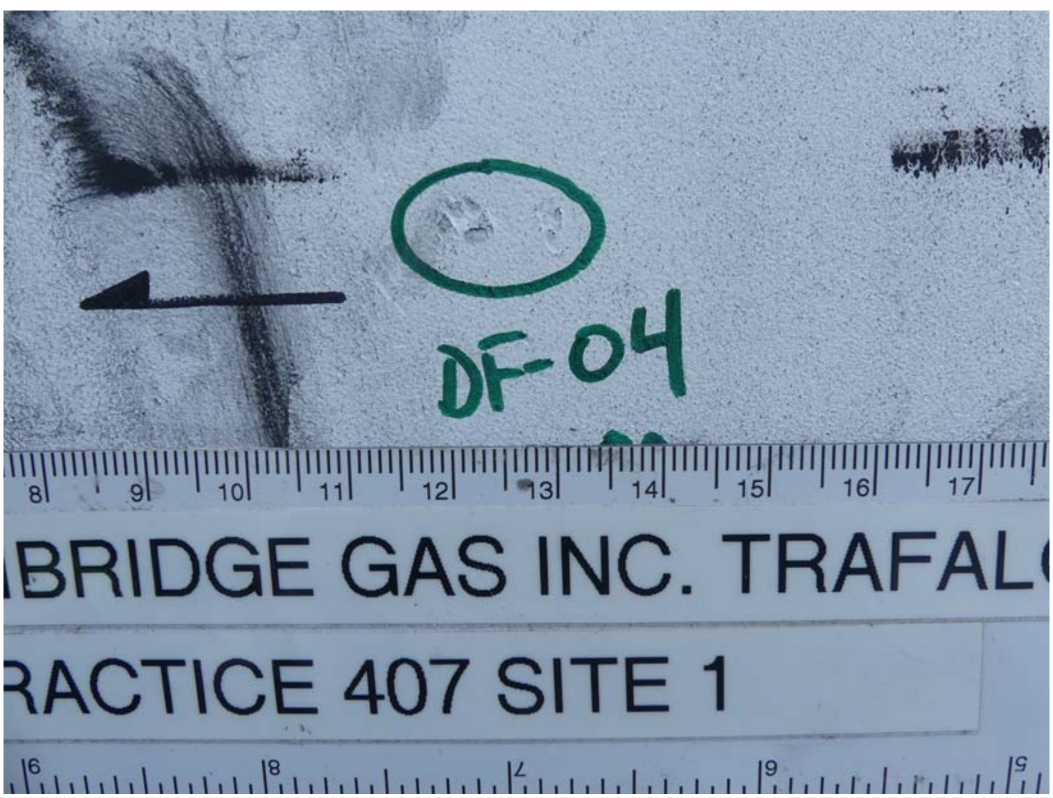


052 - DF-03 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

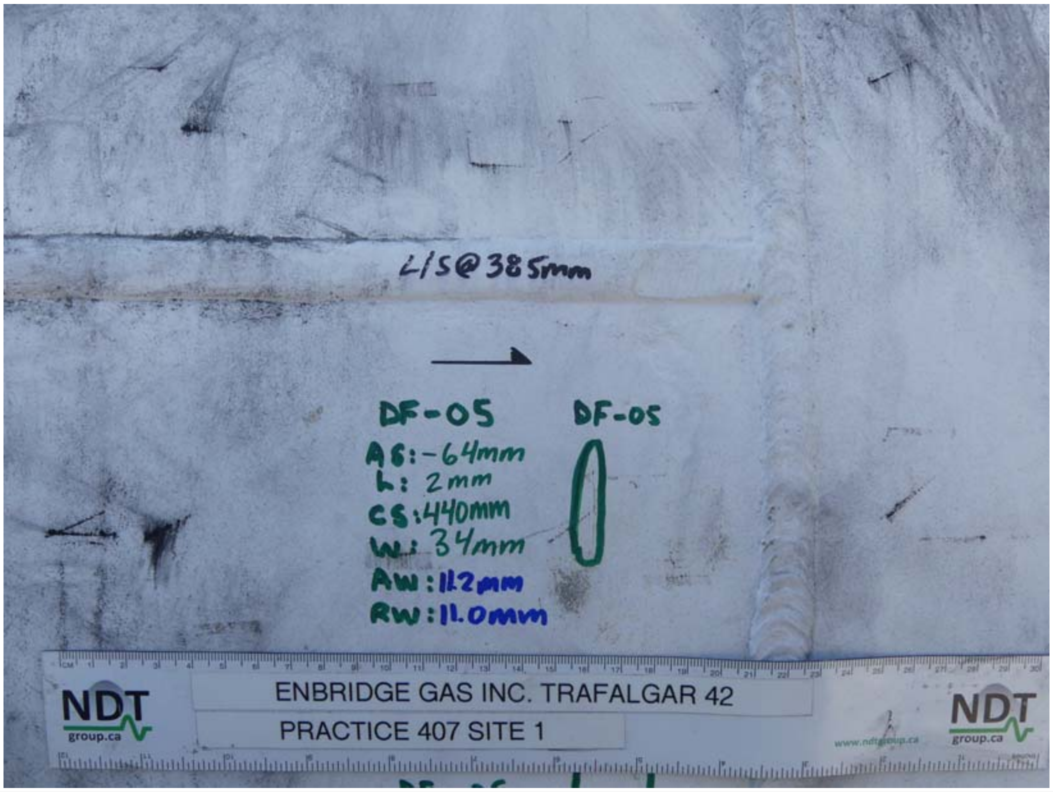


053 - DF-04

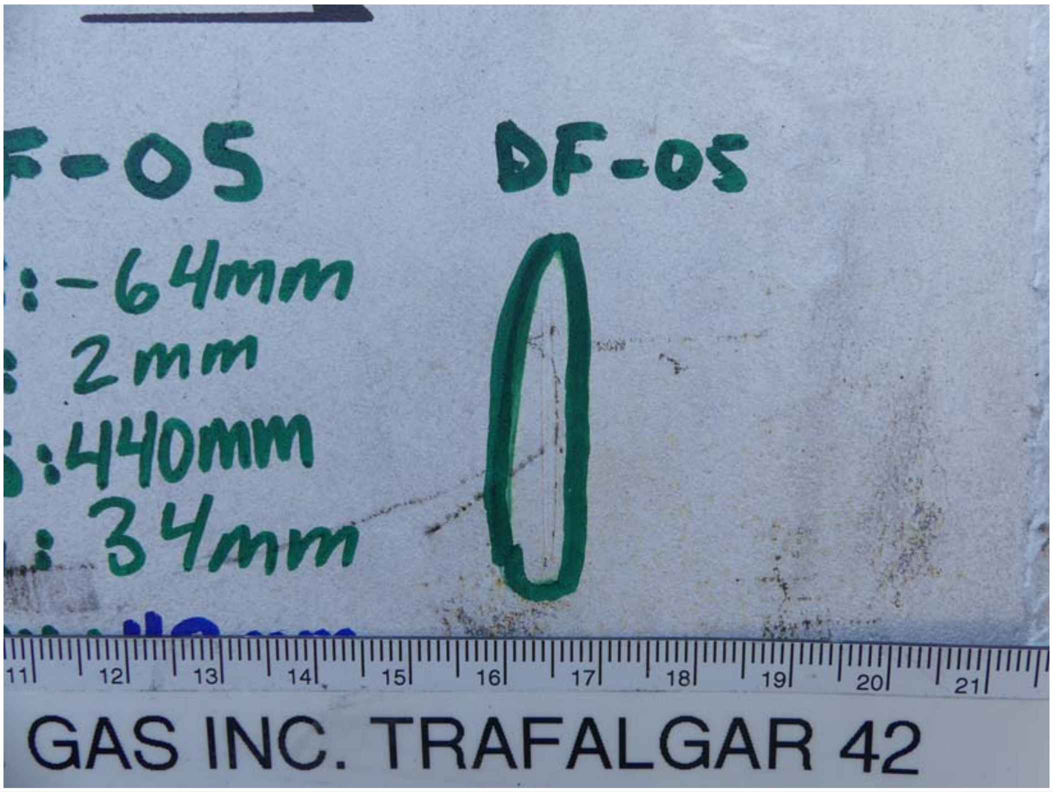


054 - DF-04 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

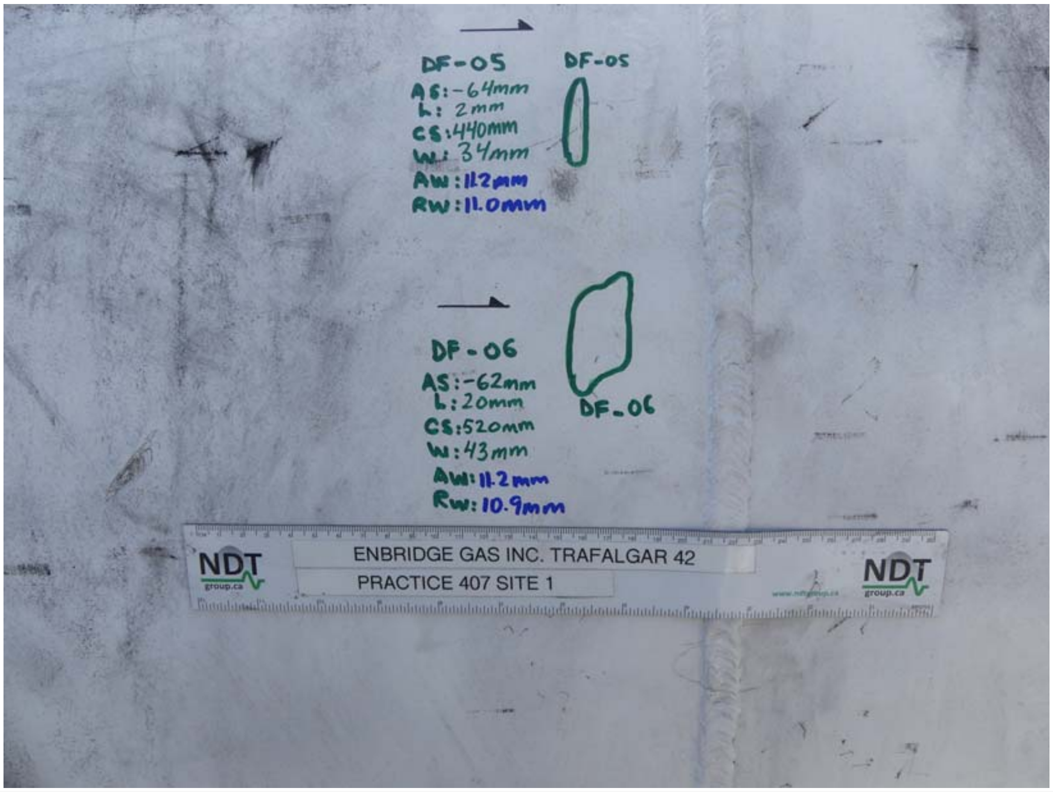


055 - DF-05

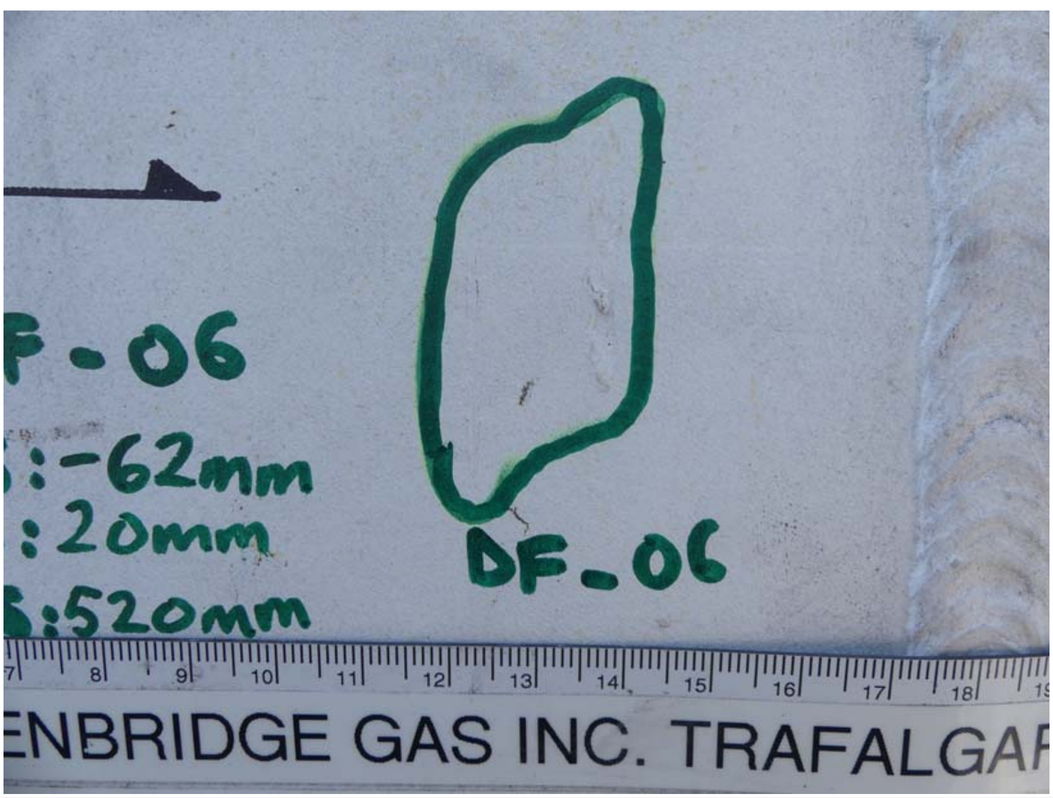


056 - DF-05 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42



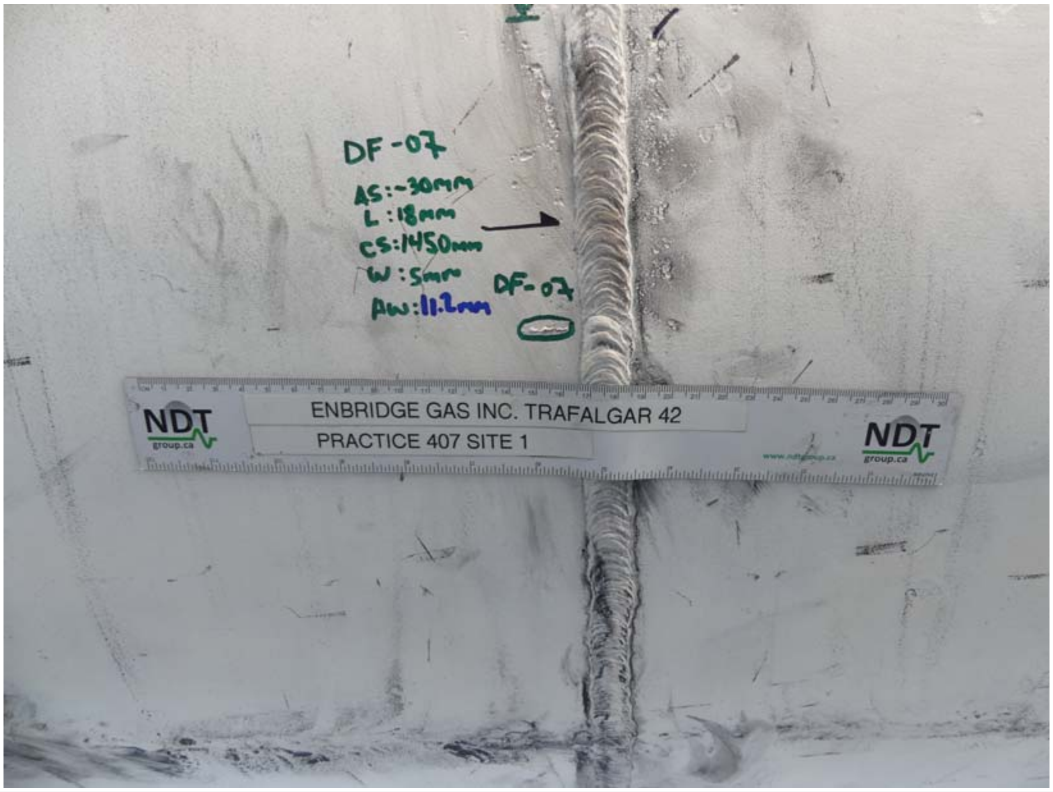
057 - DF-06



058 - DF-06 CLOSE UP

NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42

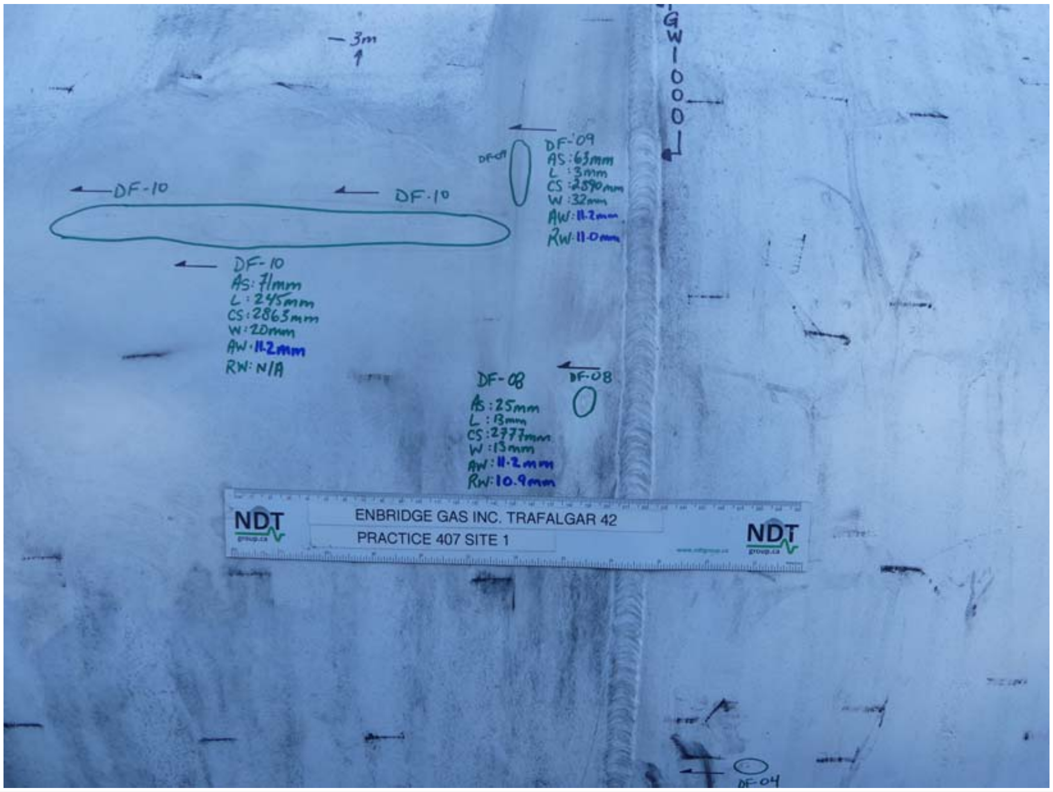


059 - DF-07

060 - DF-07 CLOSE UP

NDT group.ca

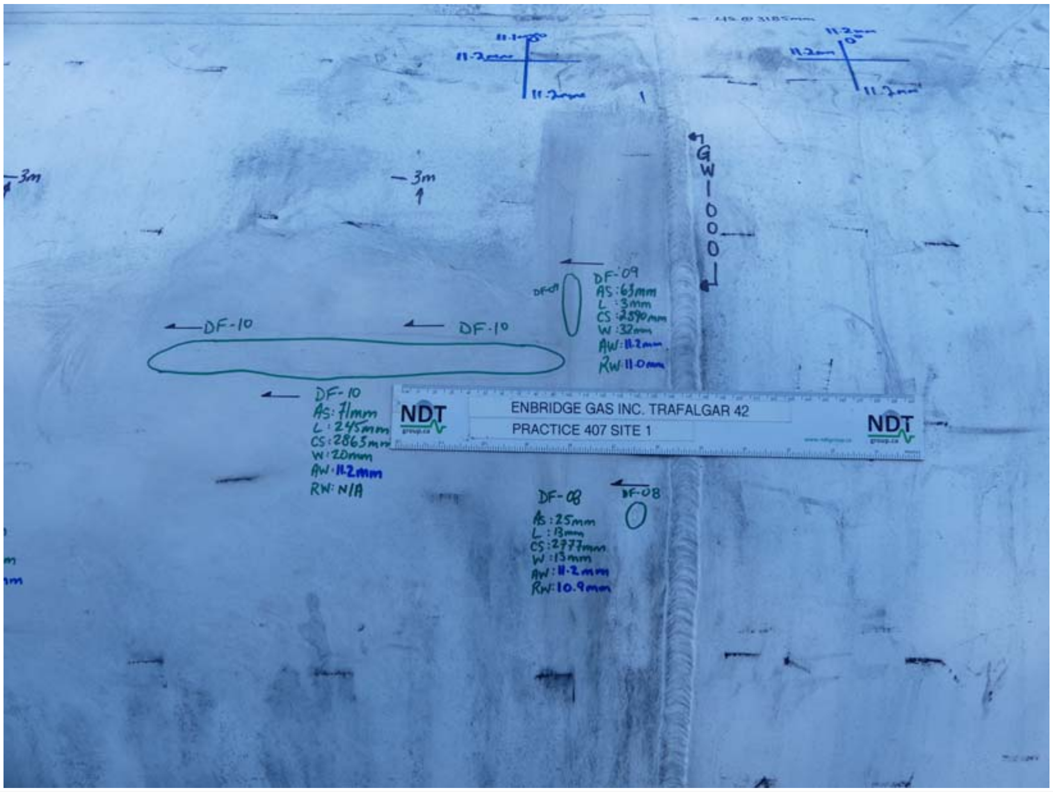
ENBRIDGE GAS INC. - TRAFALGAR NPS42



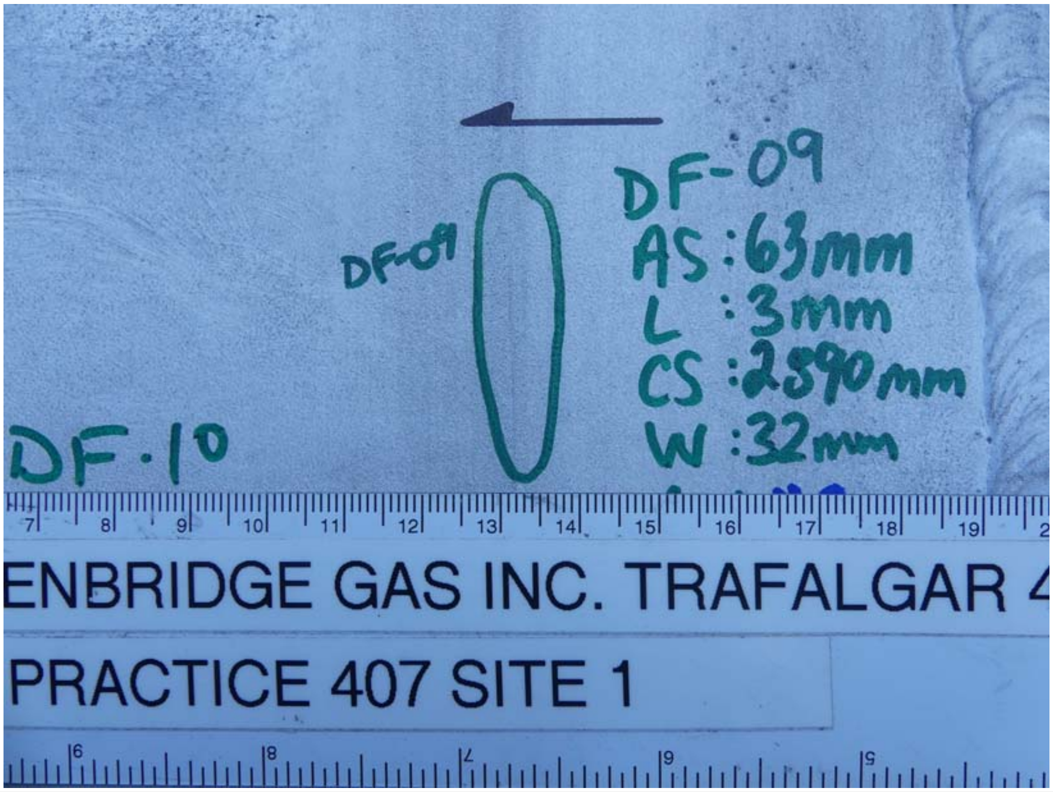
061 - DF-08

062 - DF-08 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

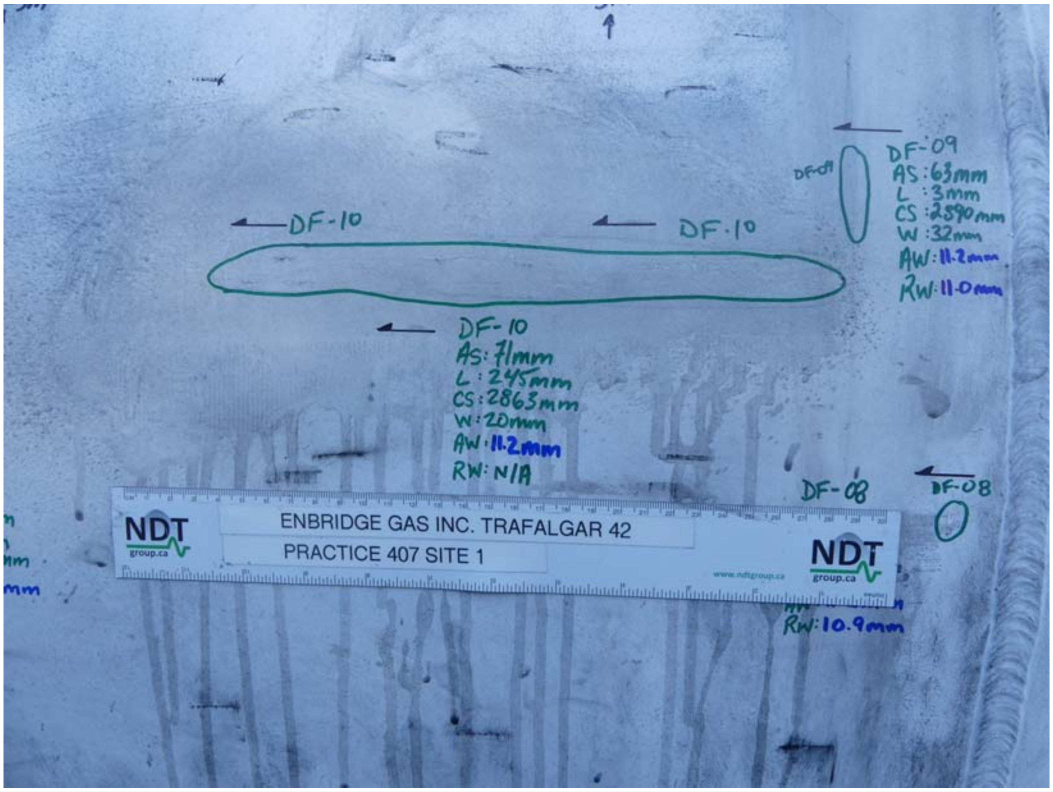


063 - DF-09

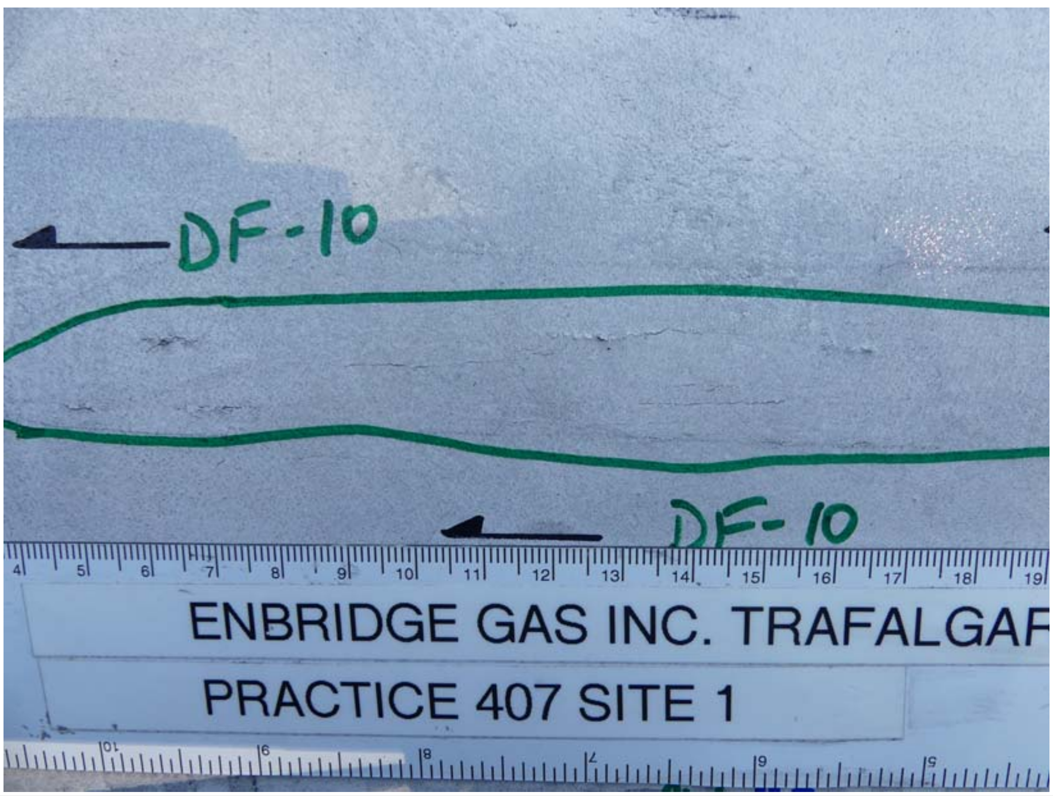


064 - DF-09 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

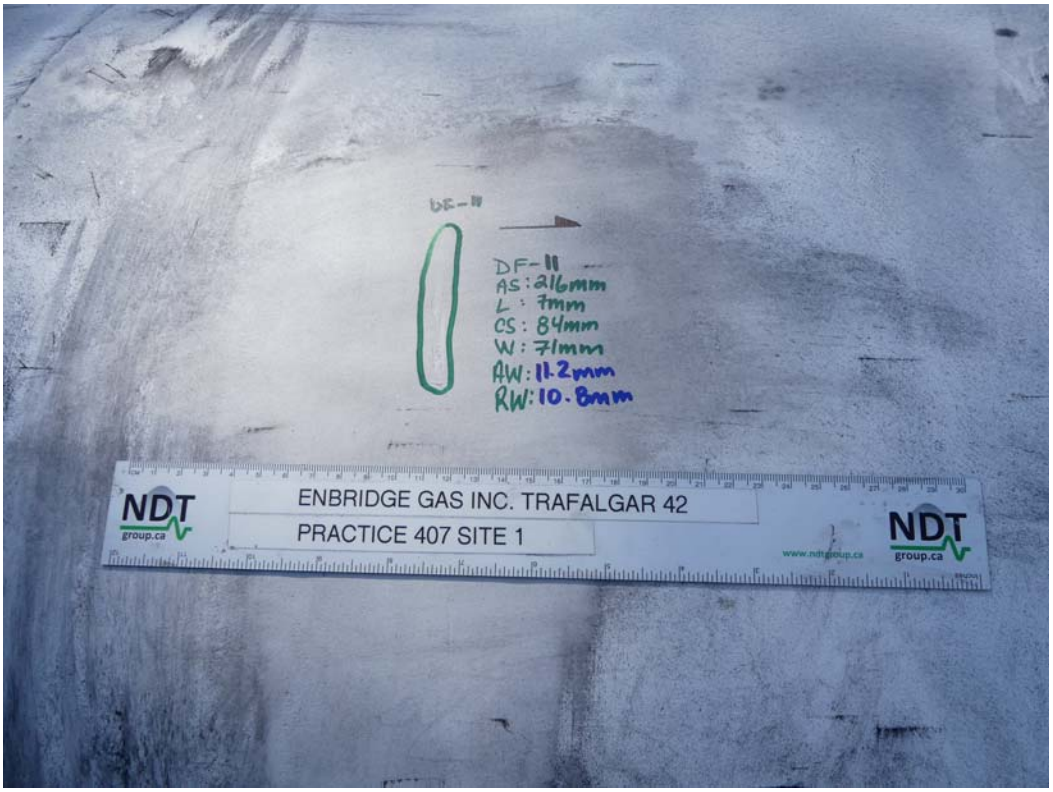


065 - DF-10

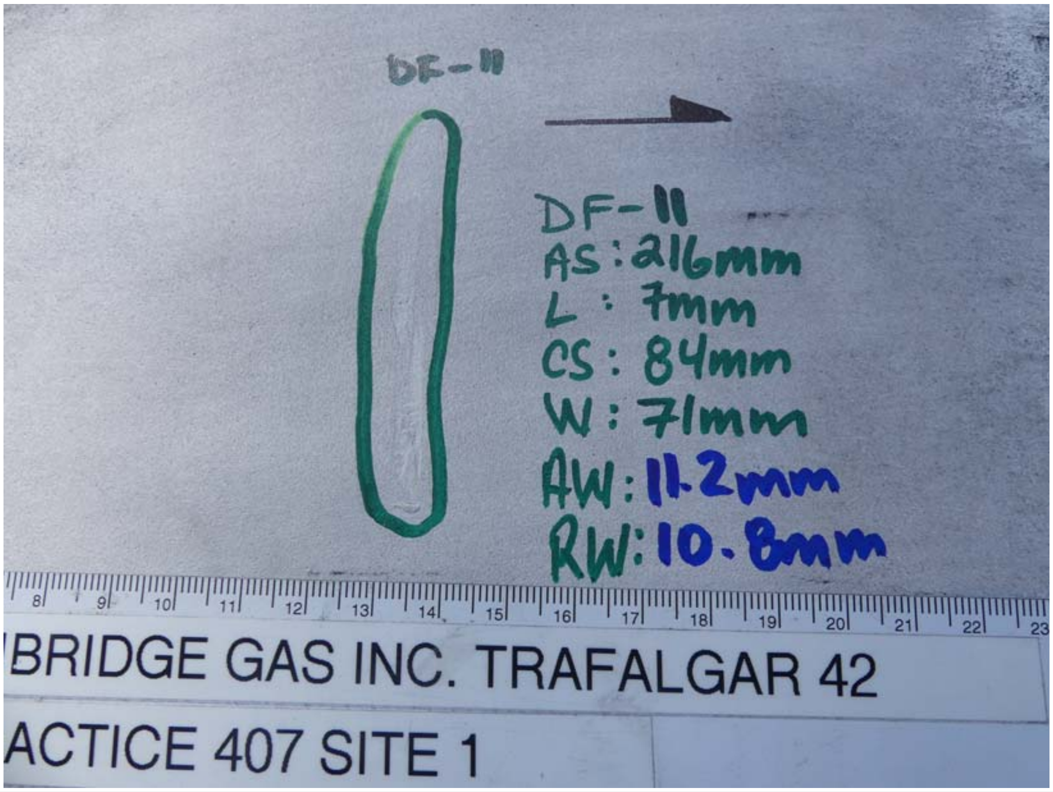


066 - DF-10 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

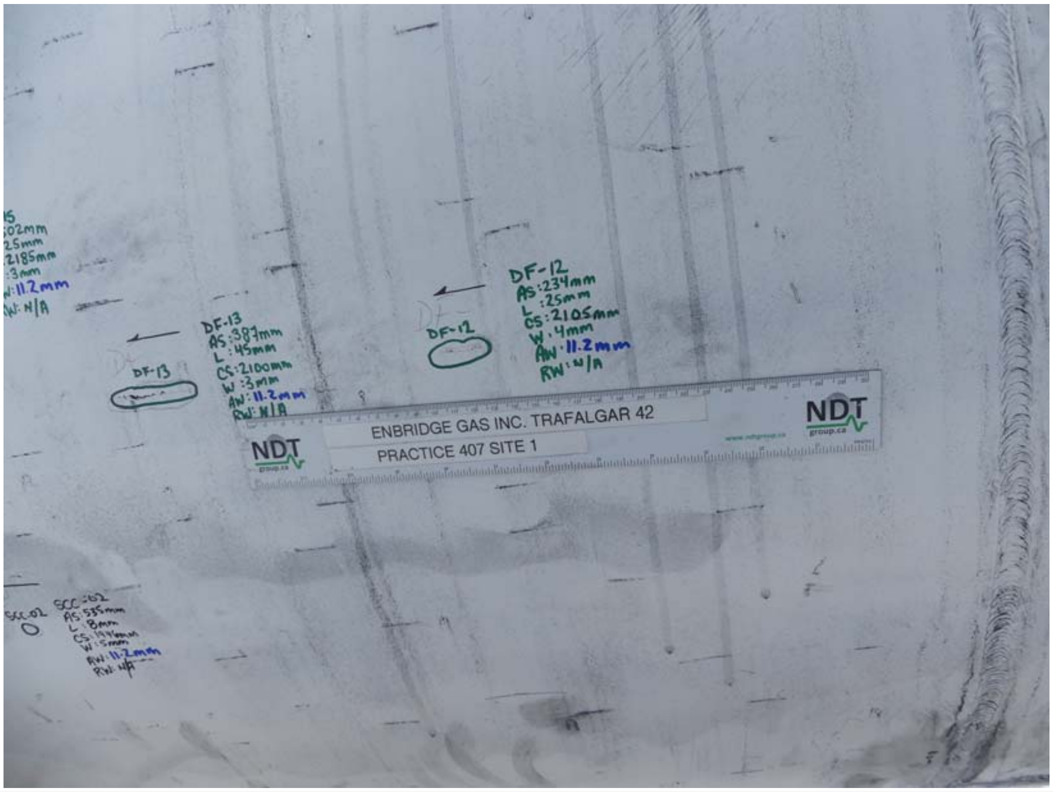


067 - DF-11

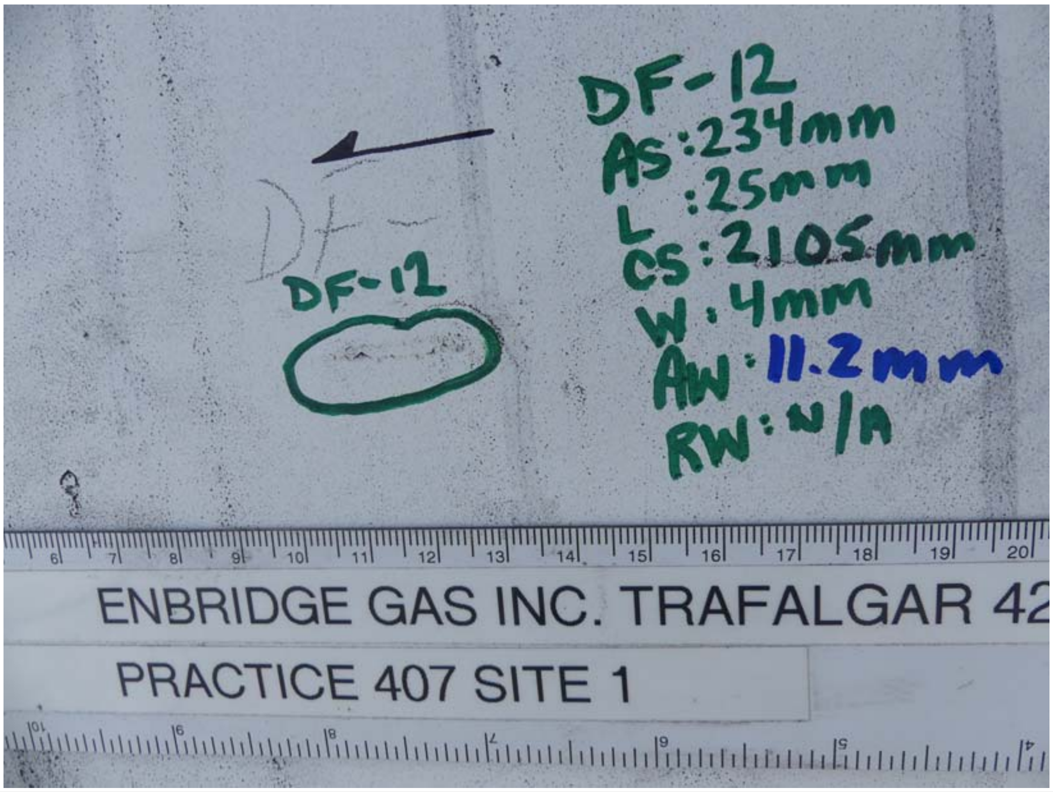


068 - DF-11 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

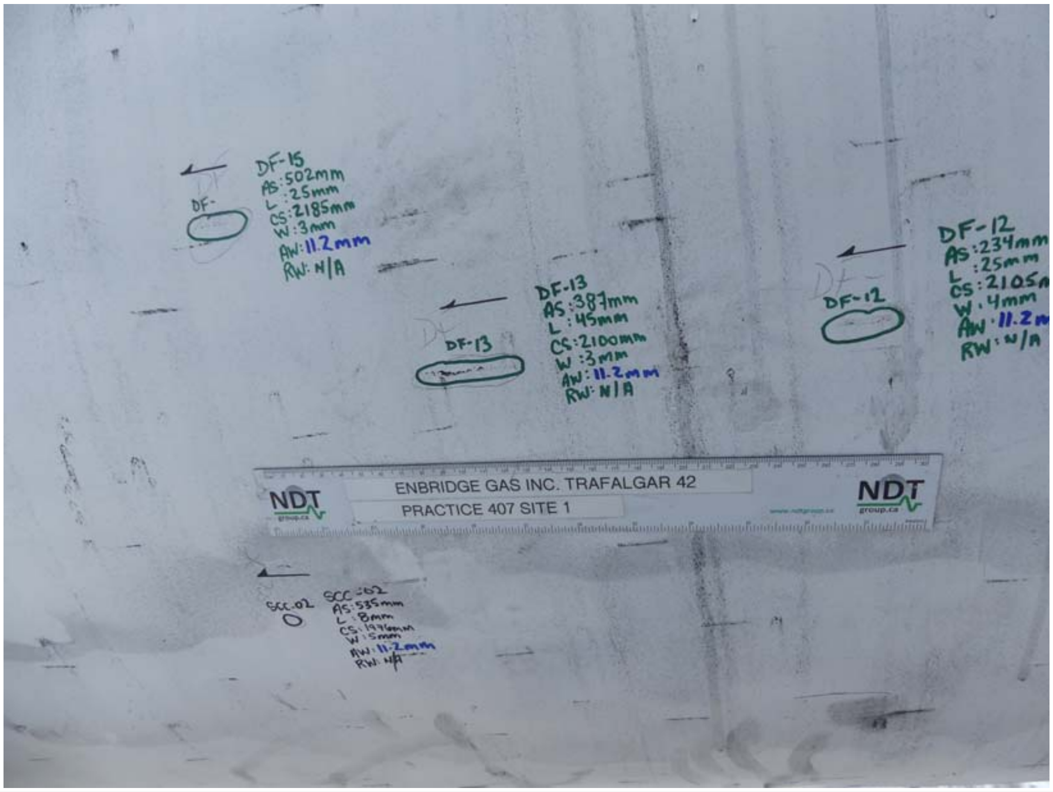


069 - DF-12

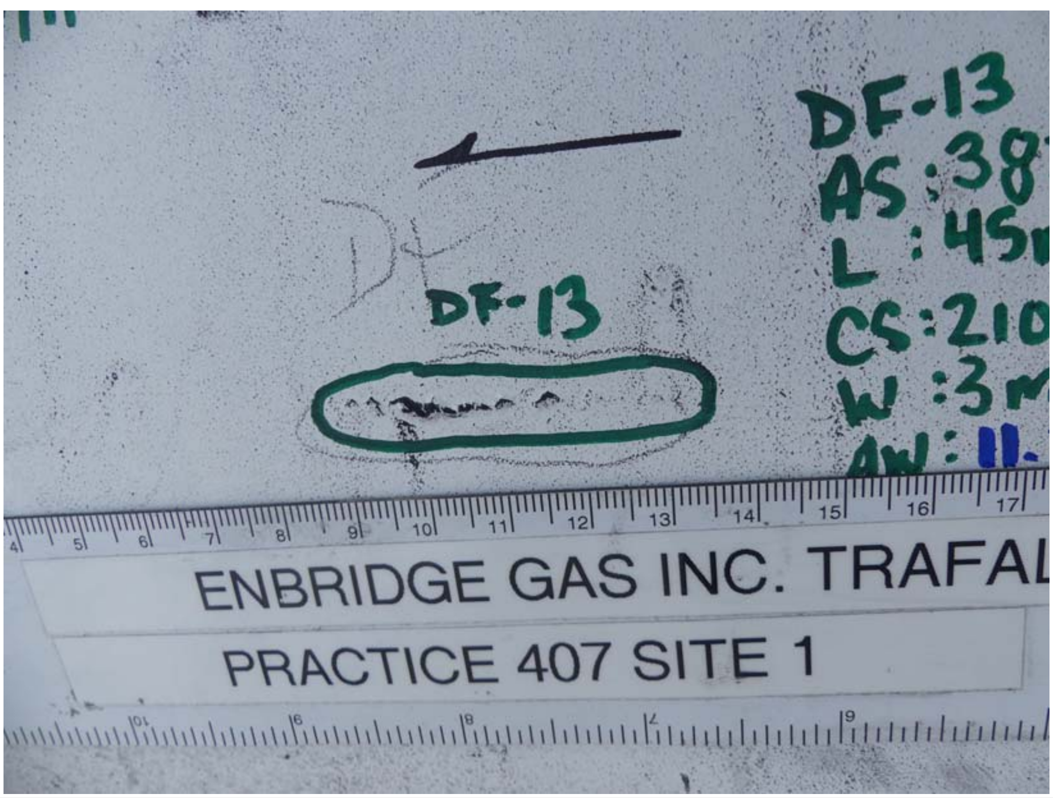


070 - DF-12 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

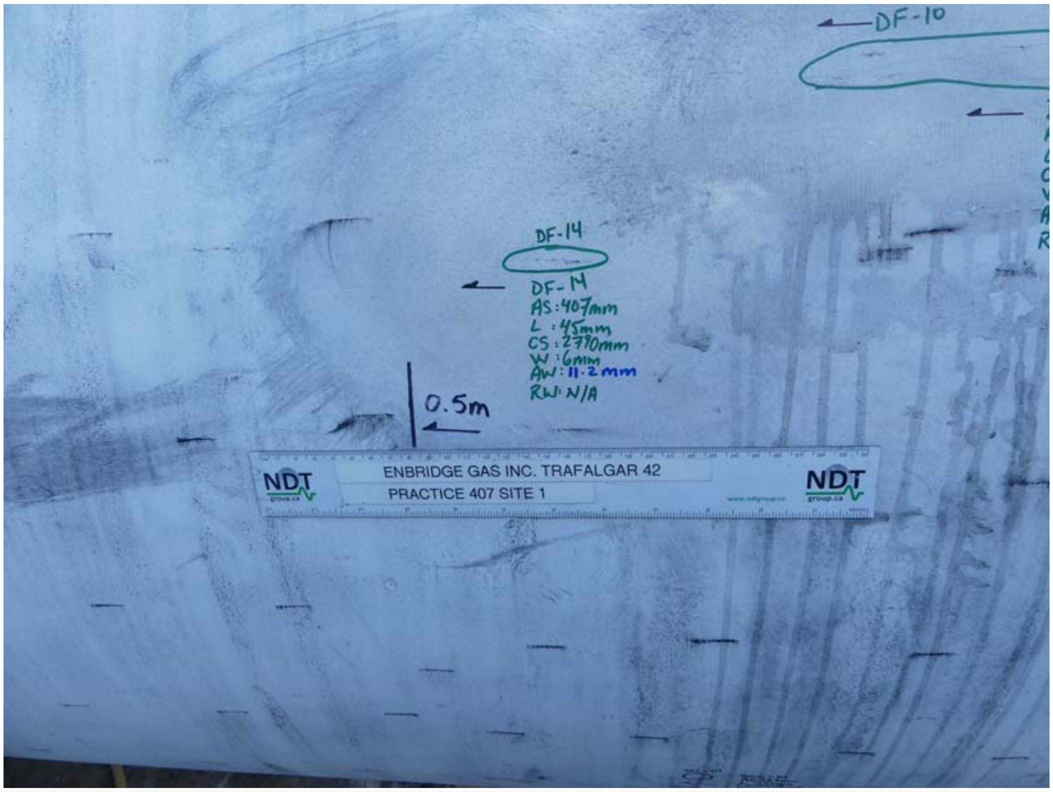


071 - DF-13



072 - DF-13 CLOSE UP

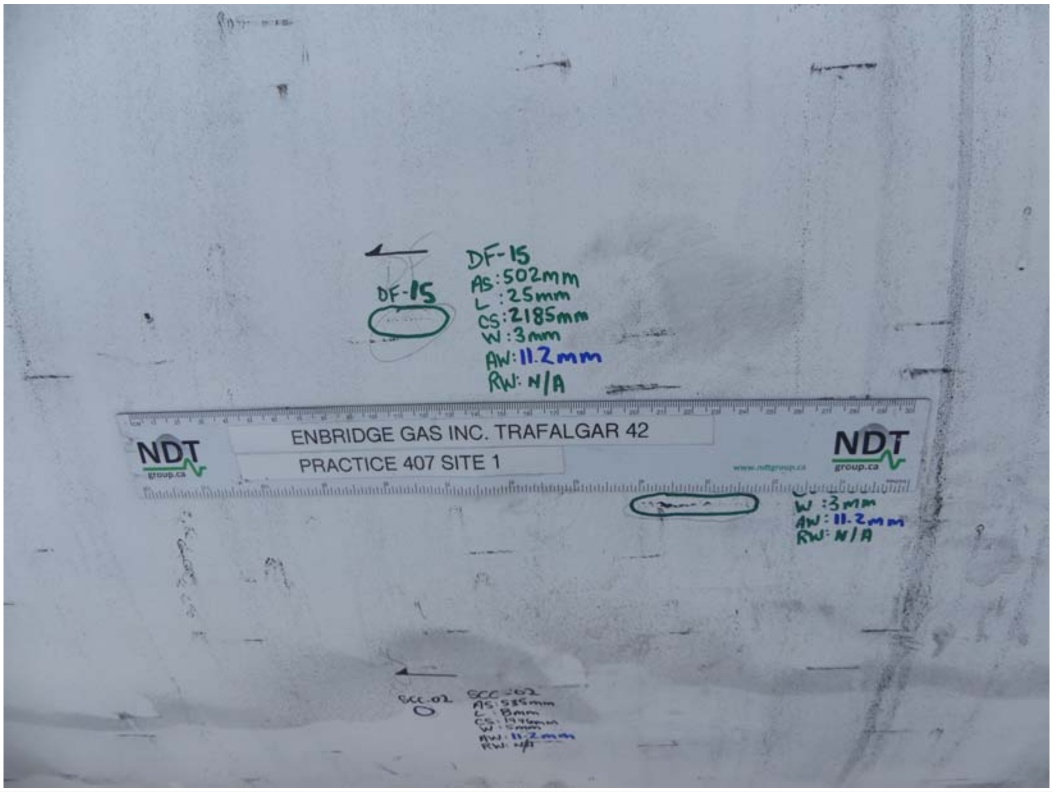
ENBRIDGE GAS INC. - TRAFALGAR NPS42



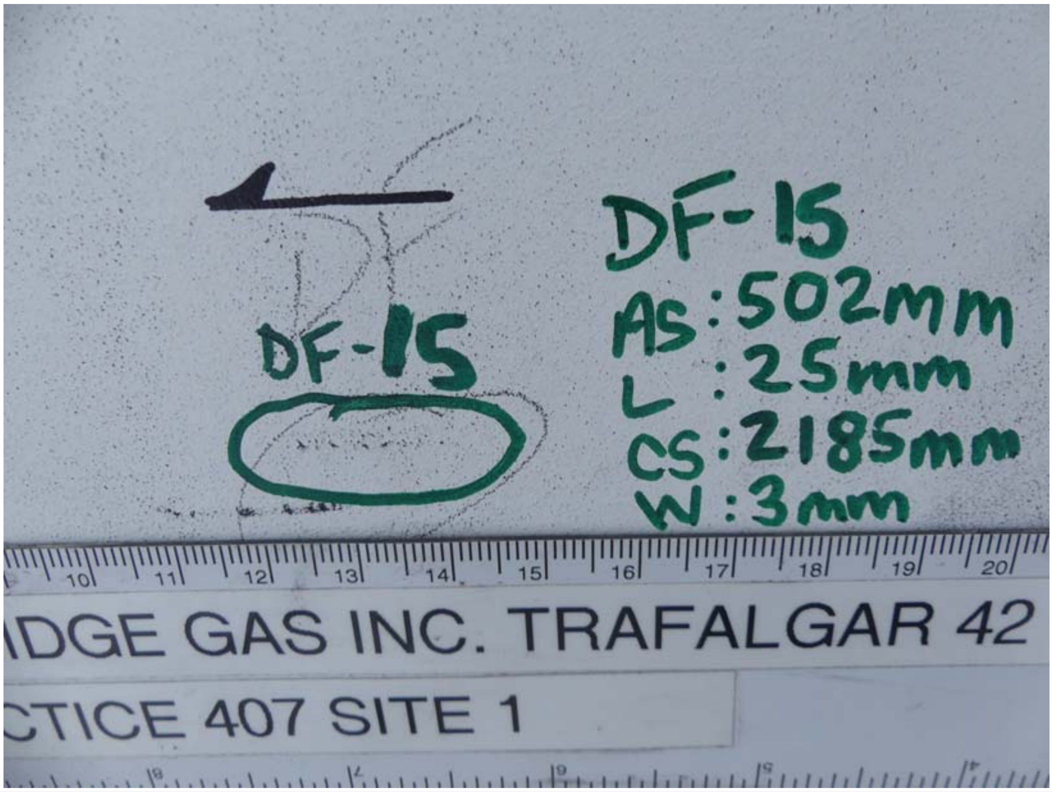
073 - DF-14

074 - DF-14 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42



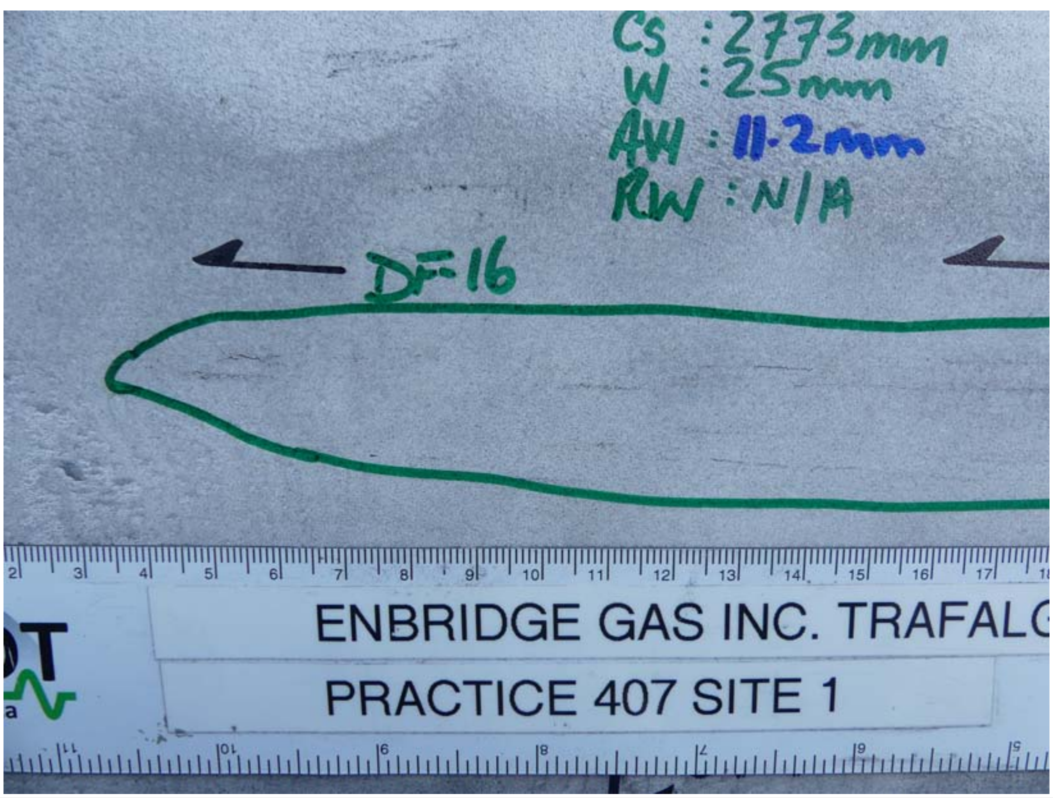
075 - DF-15



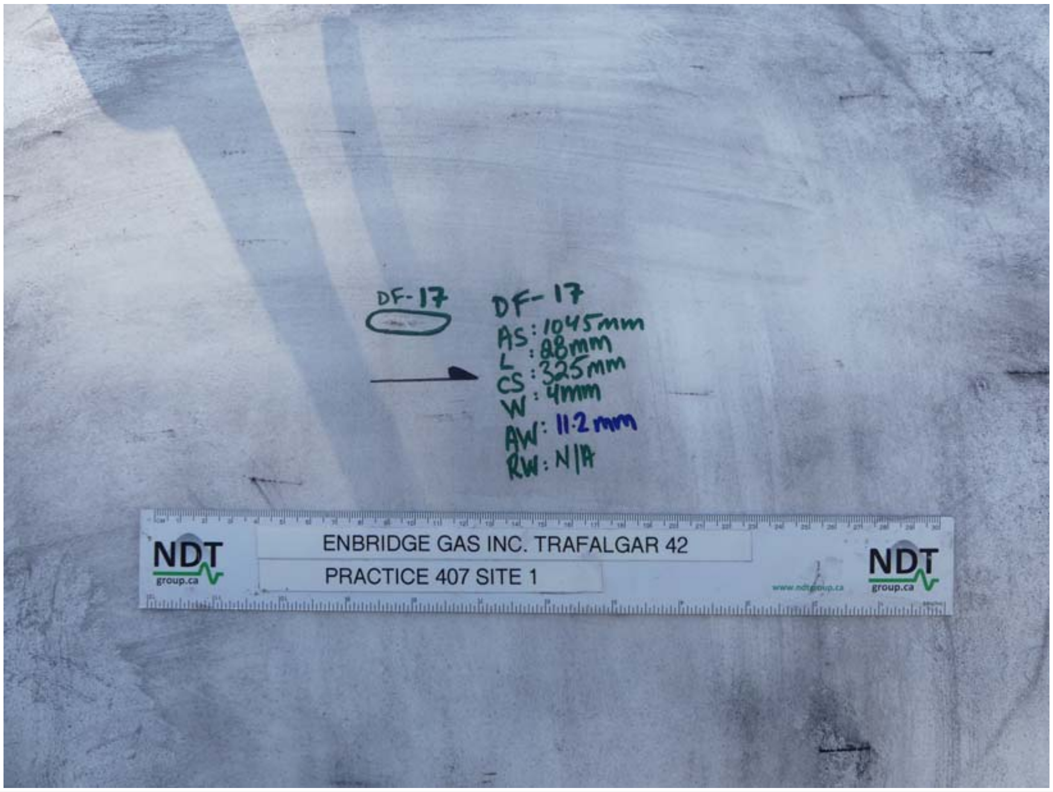
076 - DF-15 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

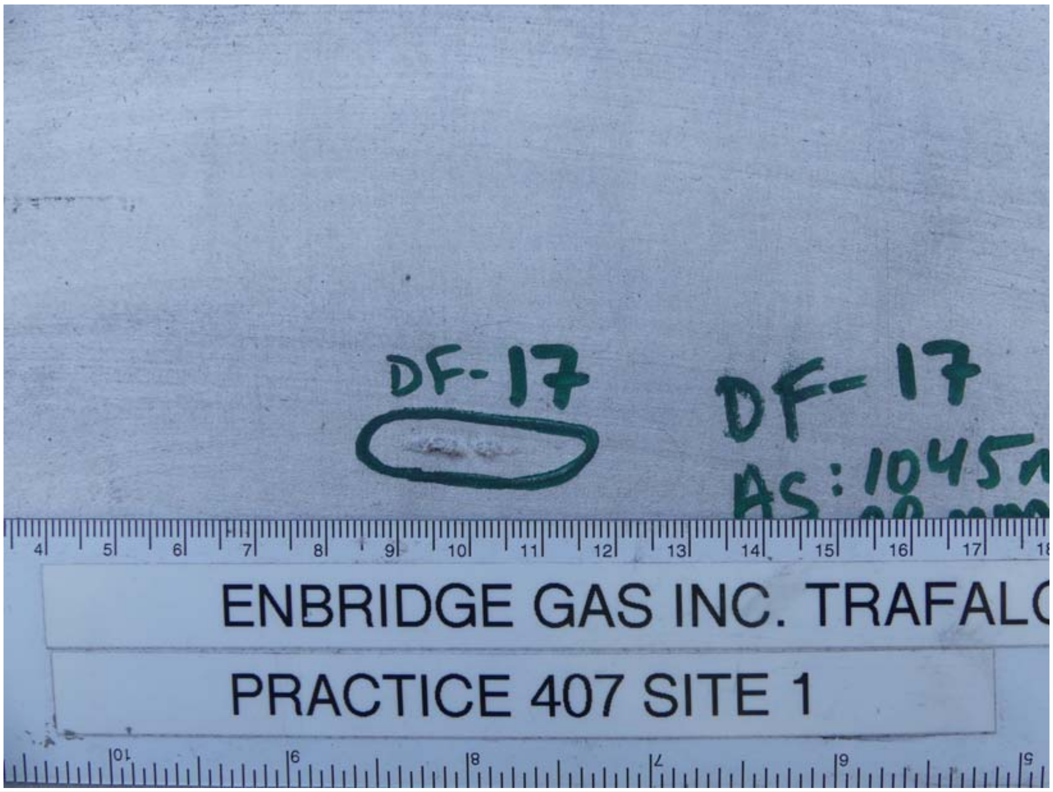
077 - DF-16



078 - DF-16 CLOSE UP

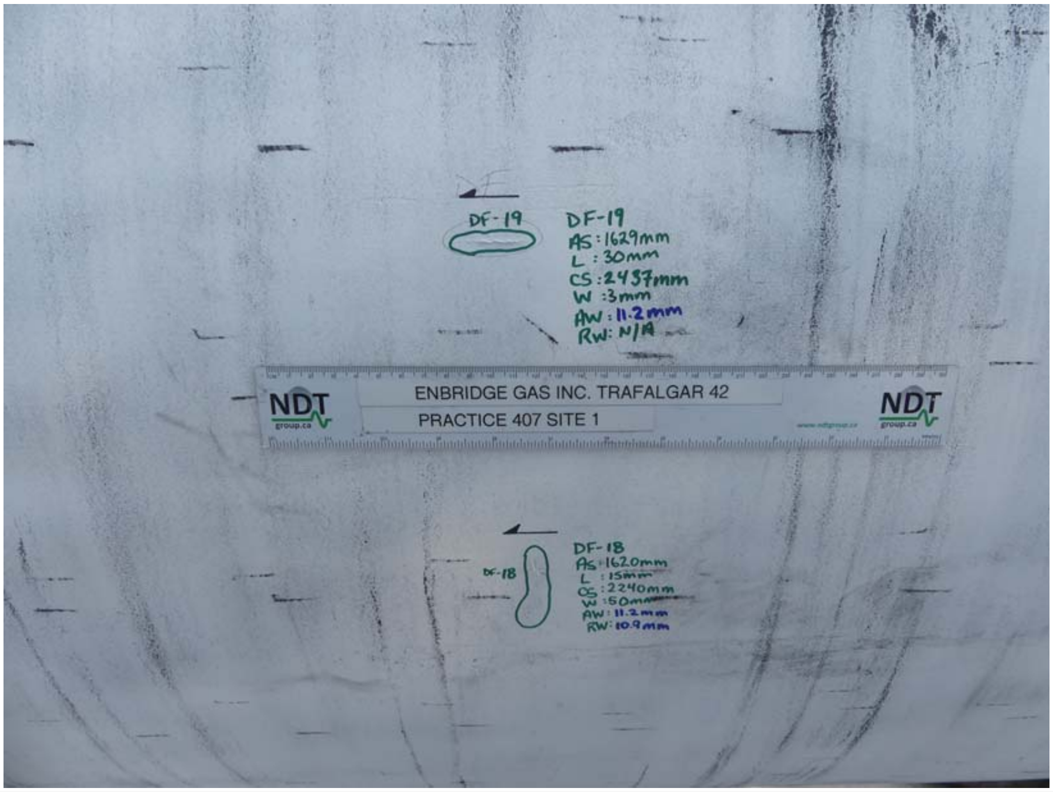


079 - DF-17

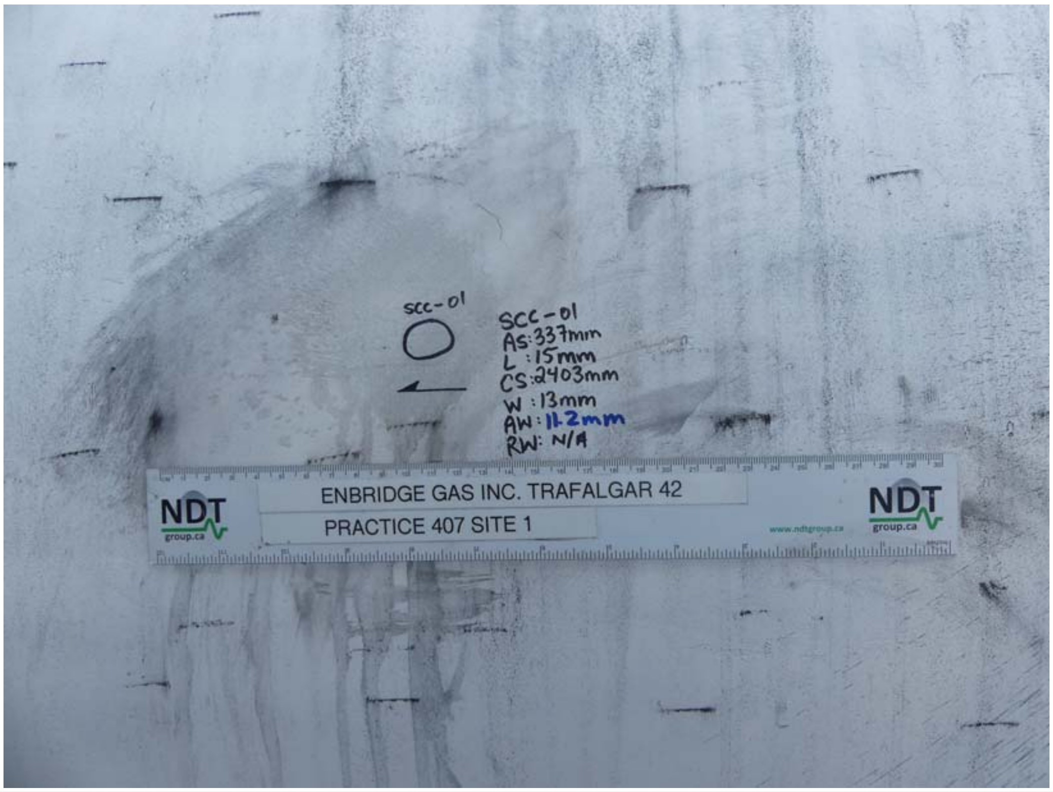


080 - DF-17 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42



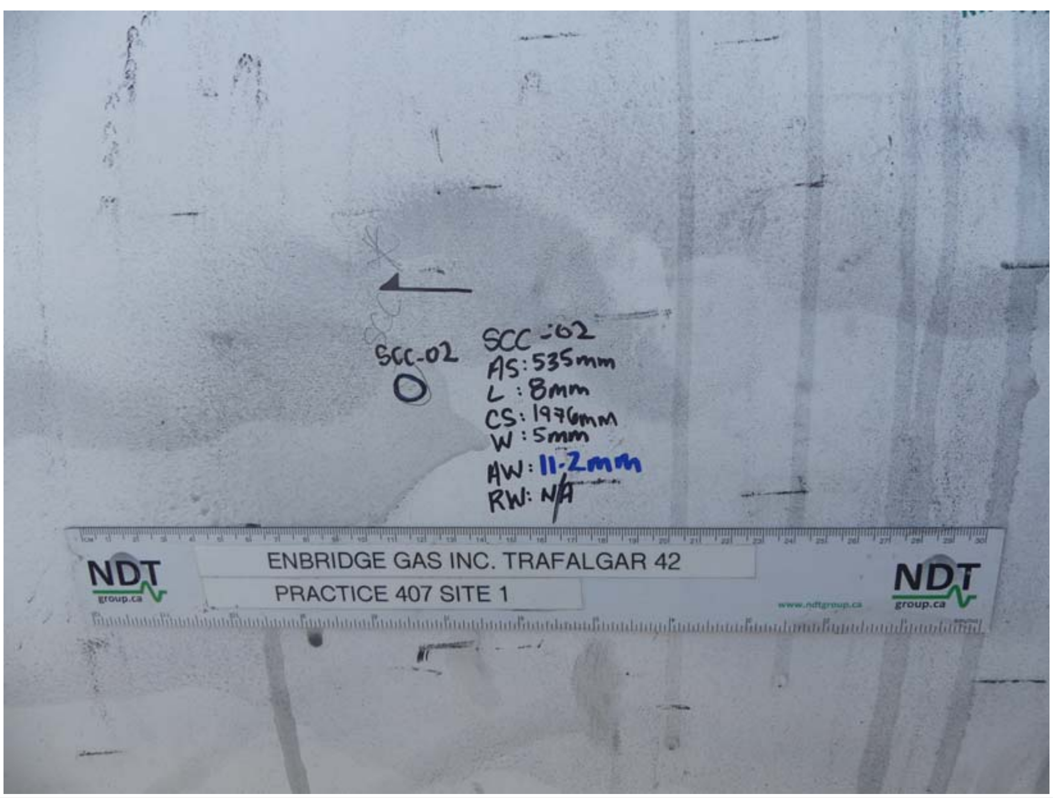
083 - DF-19



087 - SCC-01

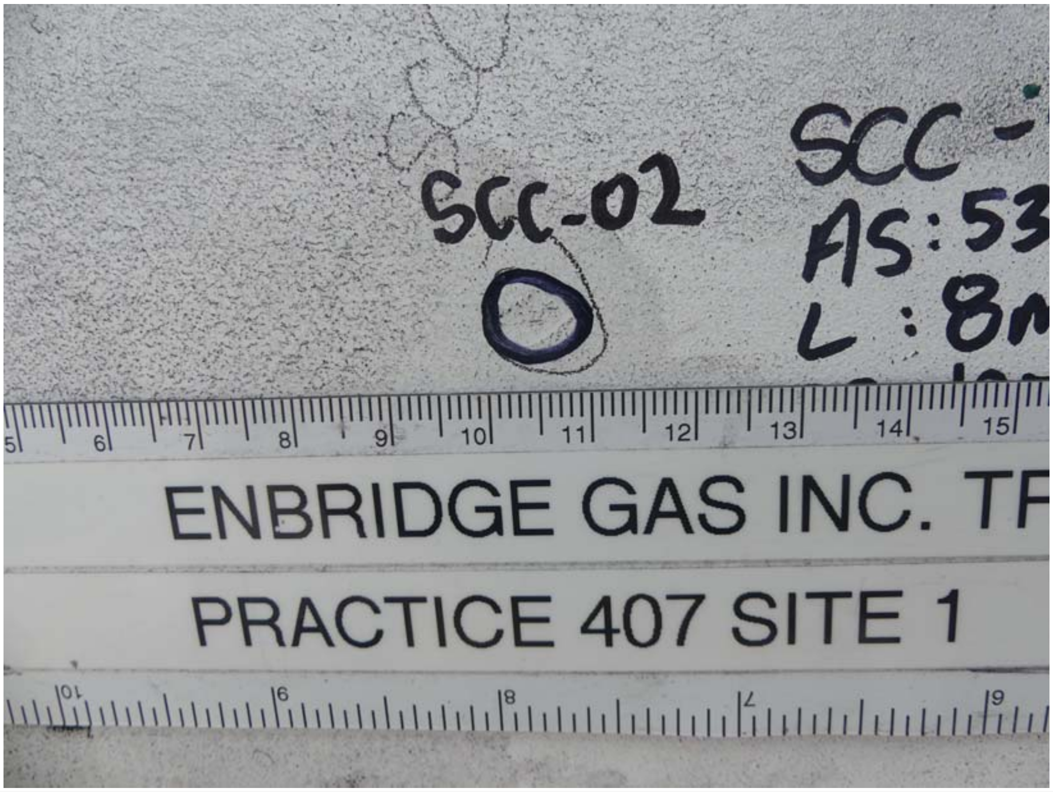
ENBRIDGE GAS INC. - TRAFALGAR NPS42

088 - SCC-01 CLOSE UP

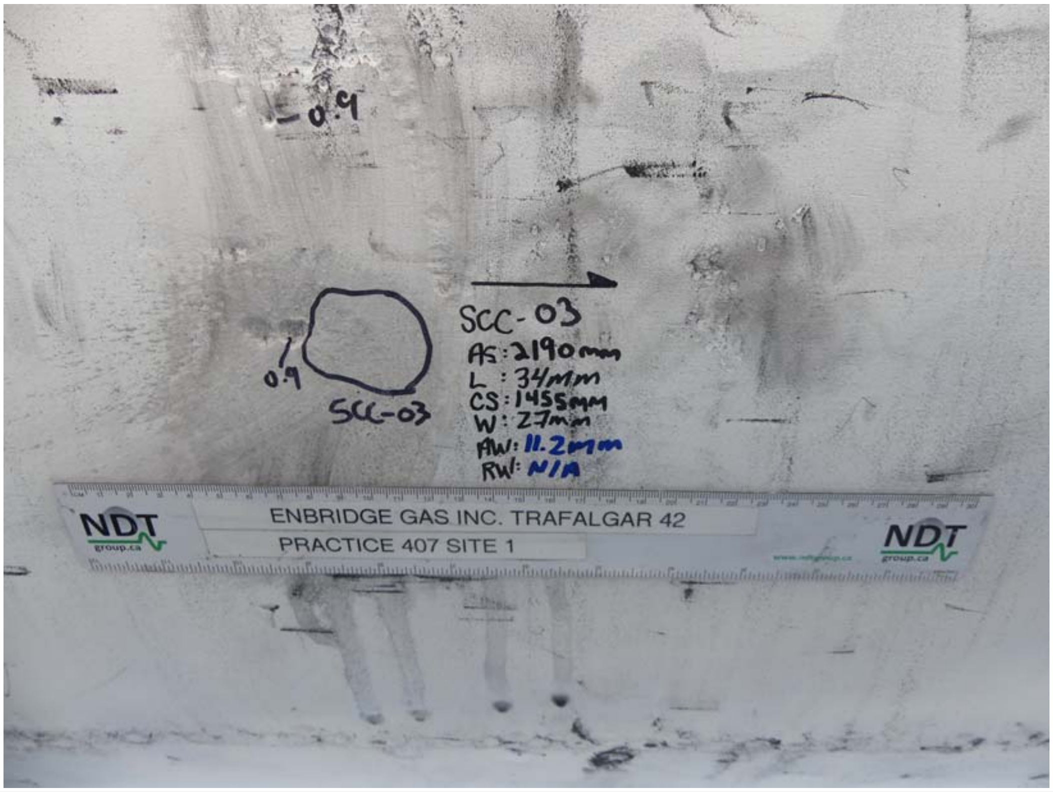


089 - SCC-02

ENBRIDGE GAS INC. - TRAFALGAR NPS42

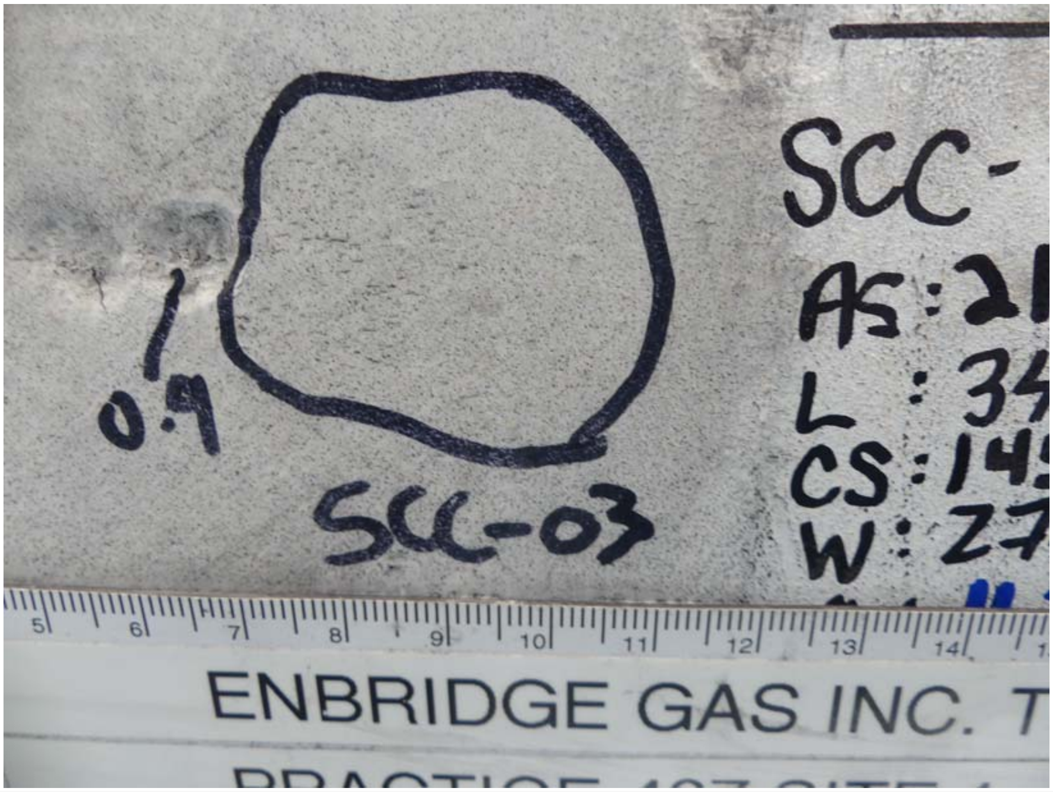


090 - SCC-02 CLOSE UP



091 - SCC-03

ENBRIDGE GAS INC. - TRAFALGAR NPS42



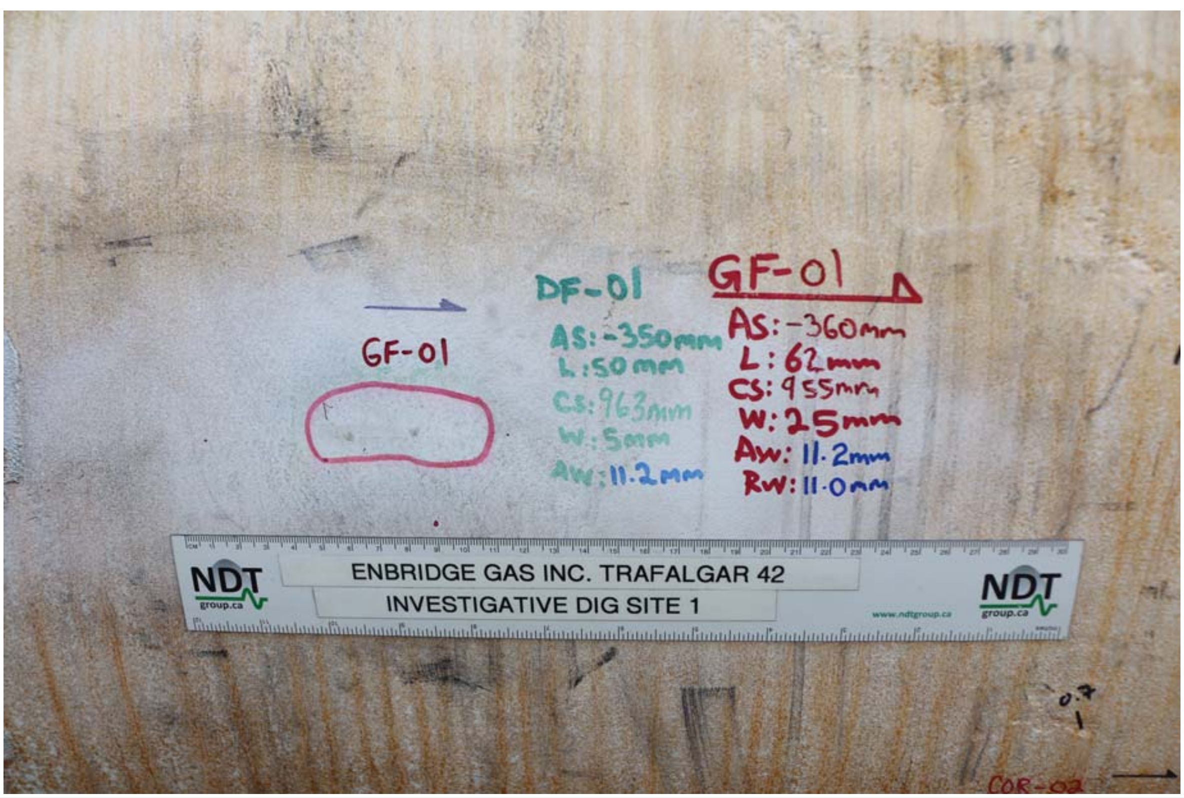
092 - SCC-03 CLOSE UP

093 - EPOXY COATING FOUND AT INITIAL EXCAVATION - BELL HOLE 1

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

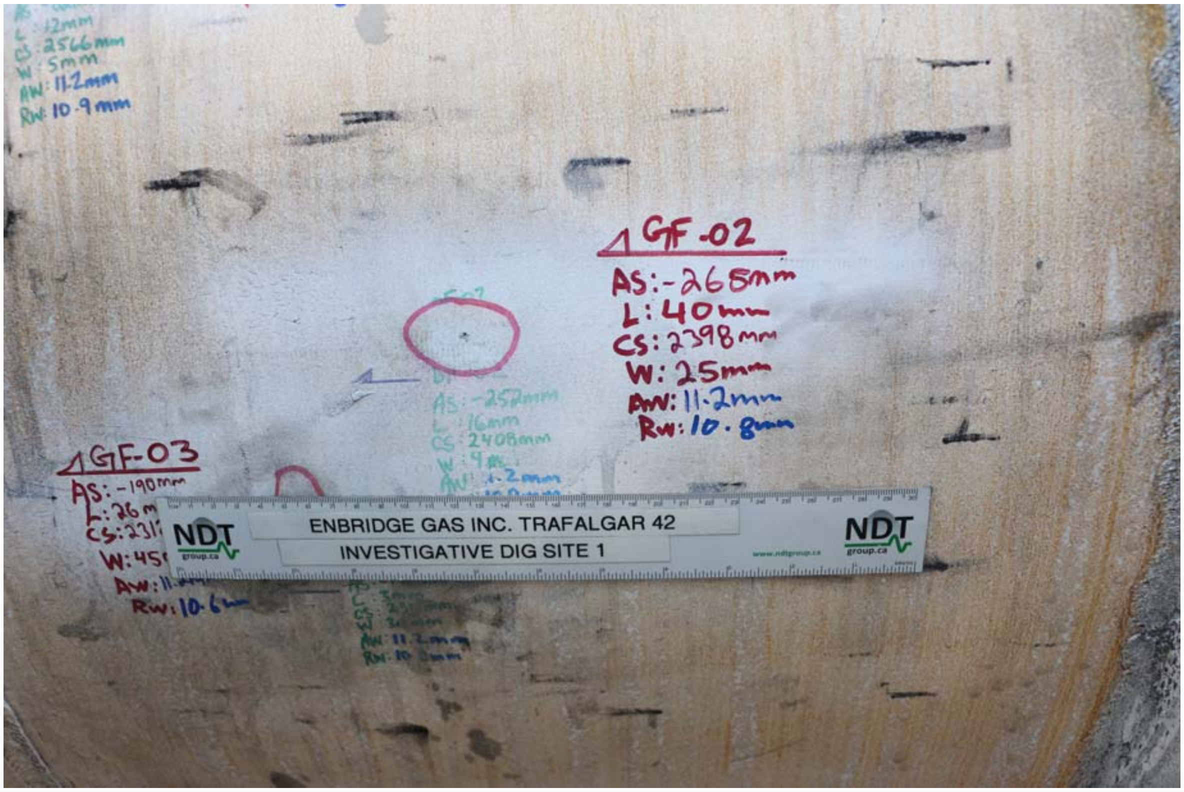
094 - EPOXY COATING FOUND AT INITIAL EXCAVATION - BELL HOLE 2



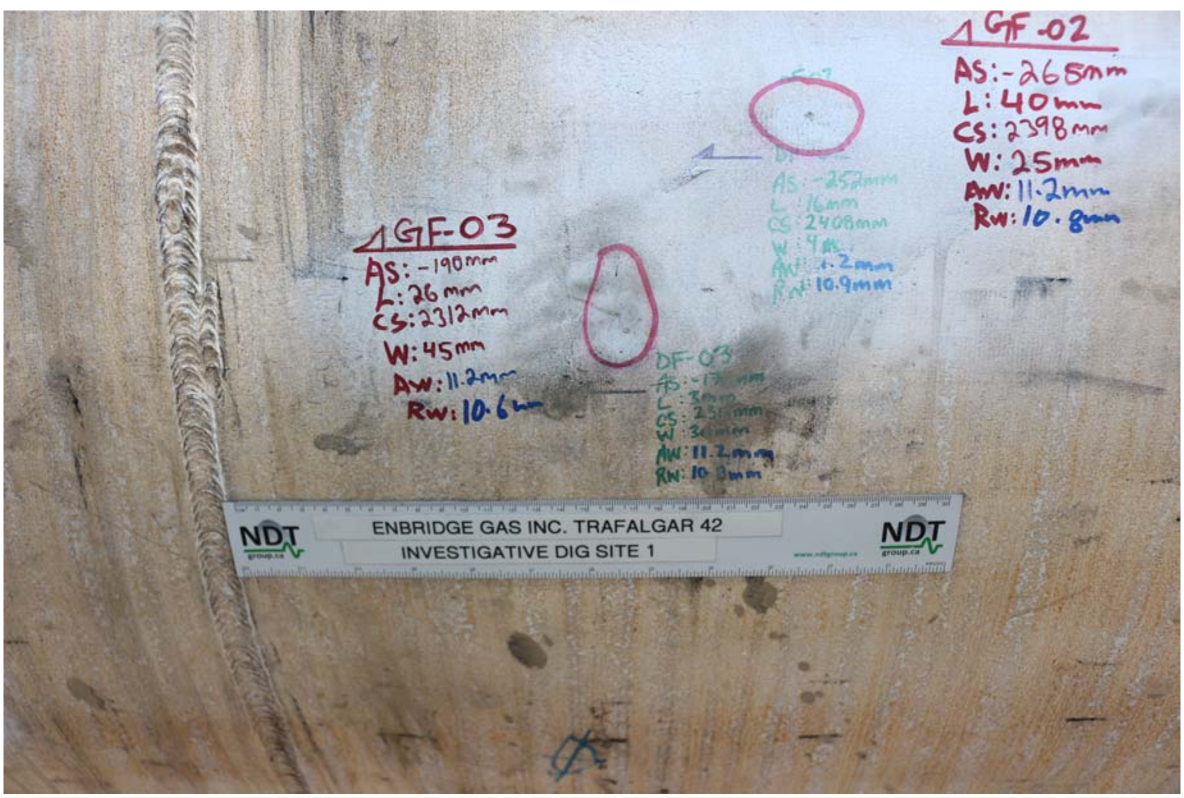
095 - GF-01

SITE 1 SCC INVESTIGATIVE DIG, AUG 30, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42



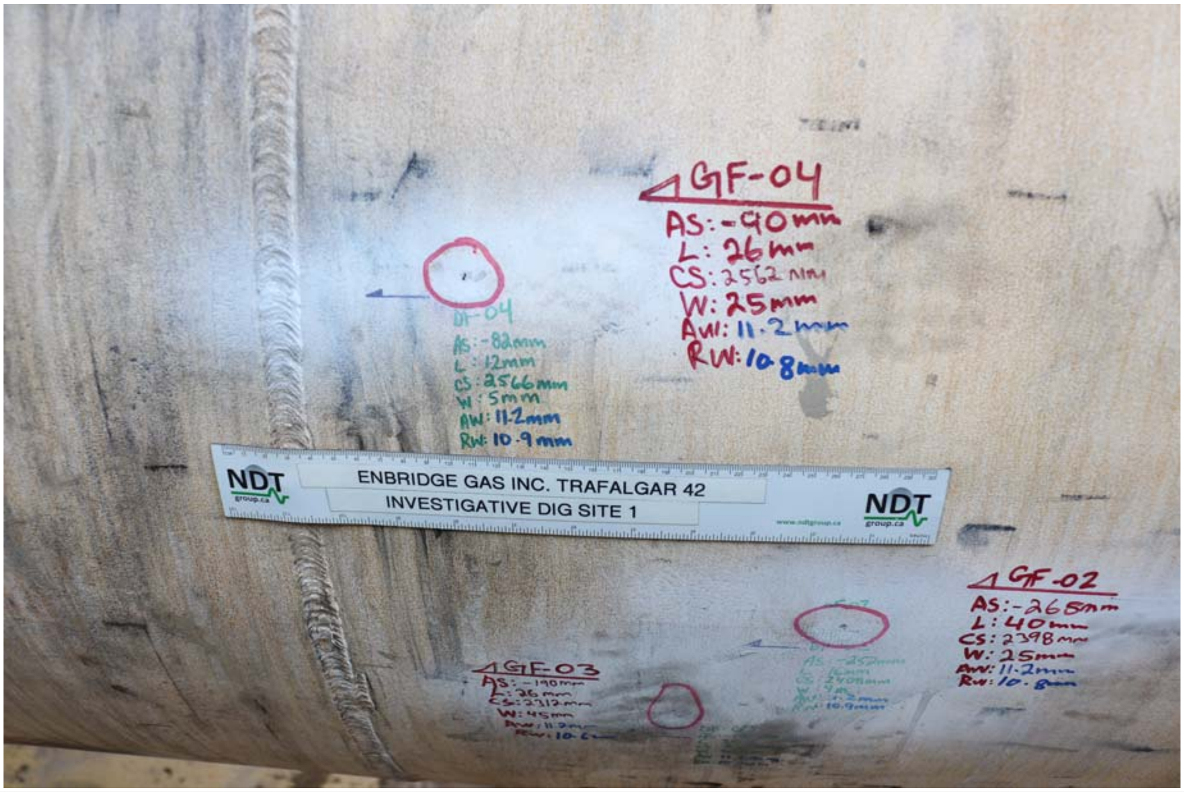
096 - GF-02



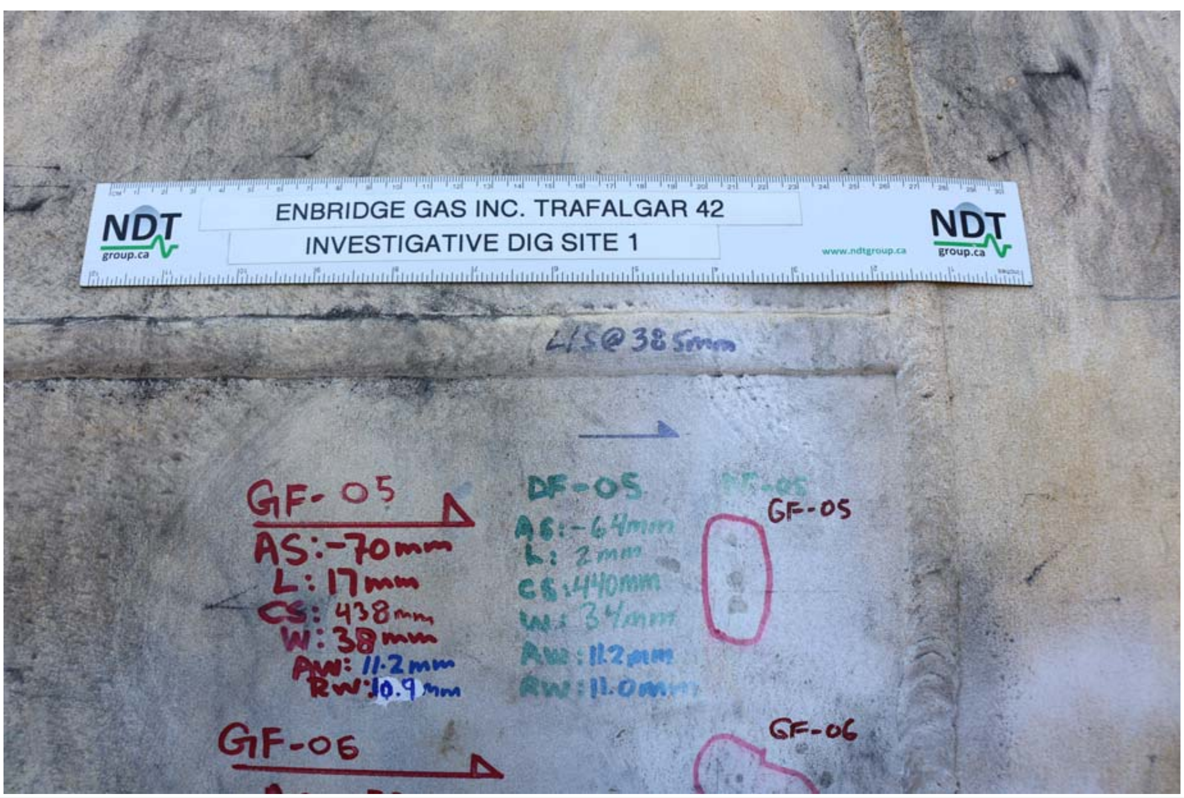
097 - GF-03

NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42



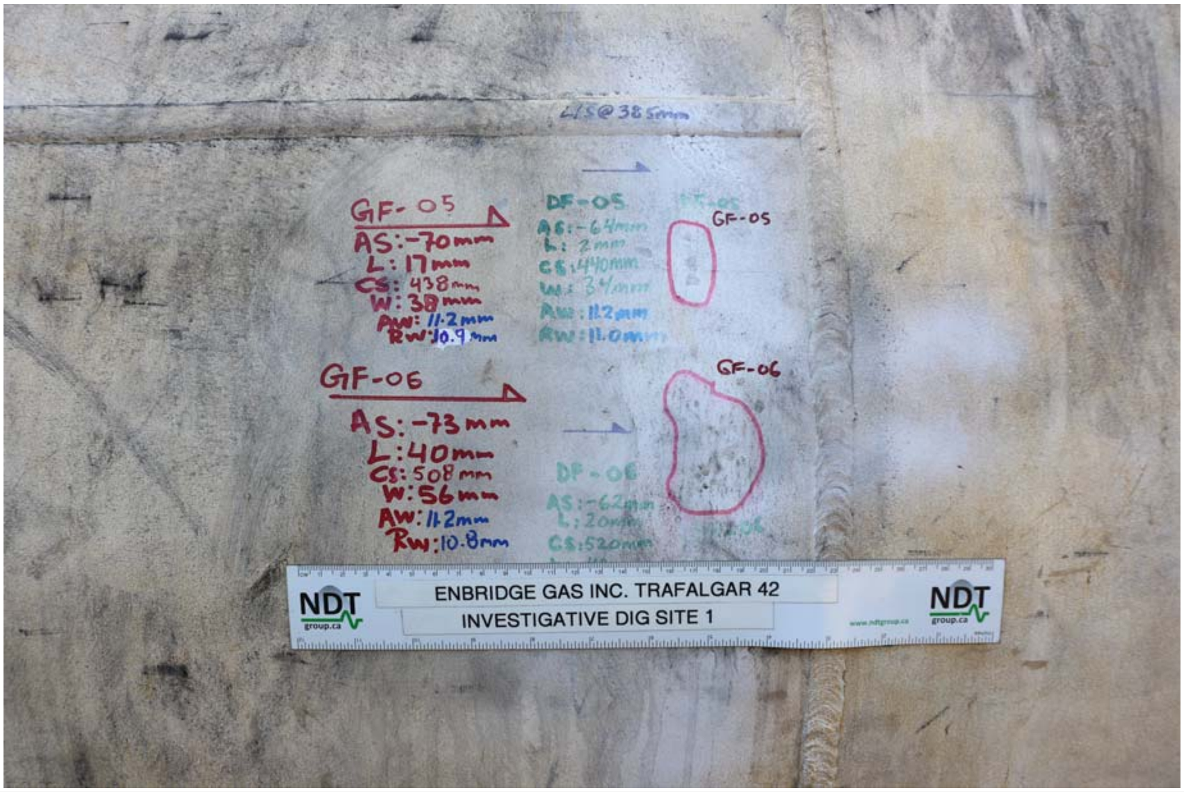
098 - GF-04



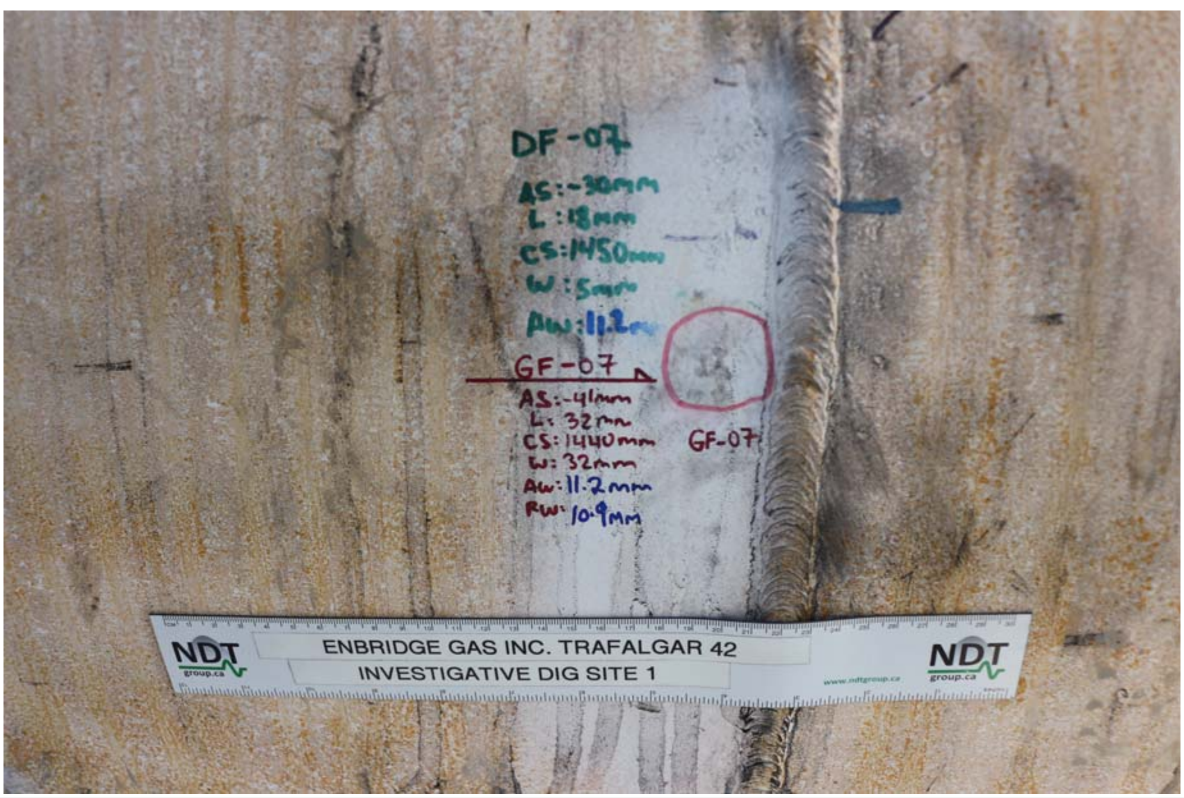
099 - GF-05

NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42

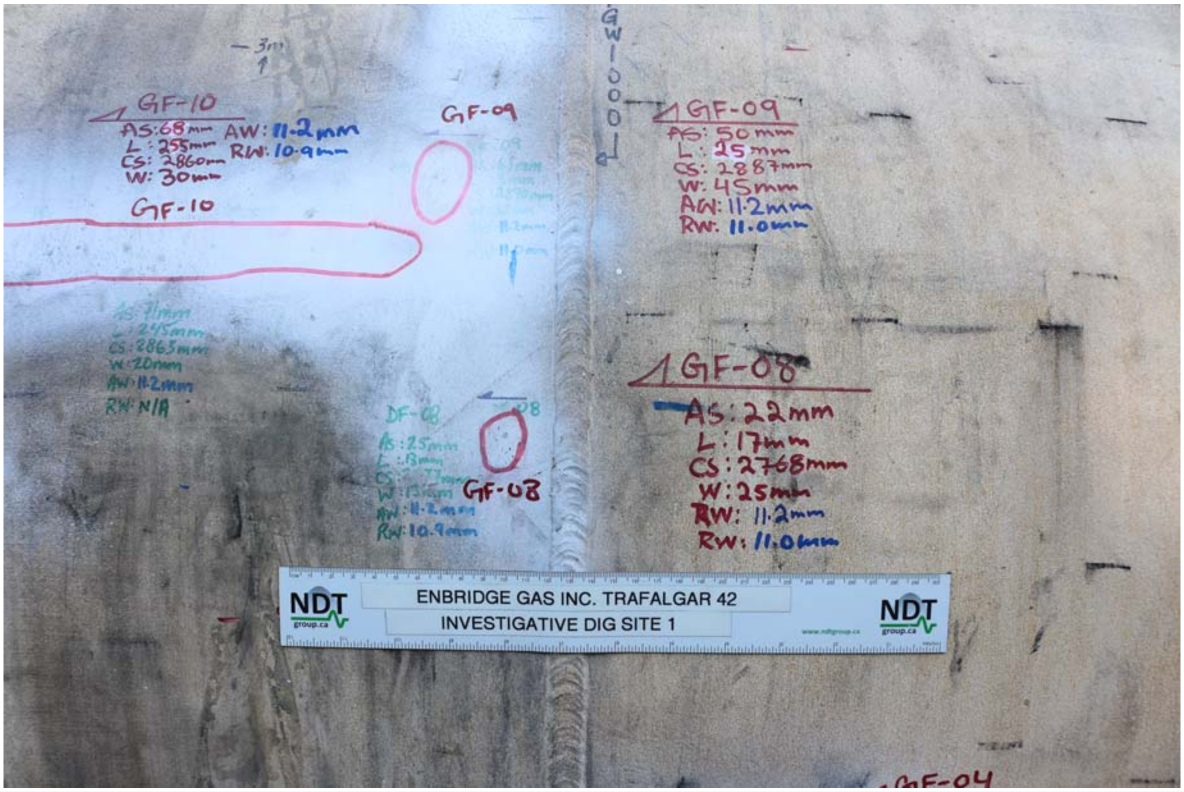


100 - GF-06

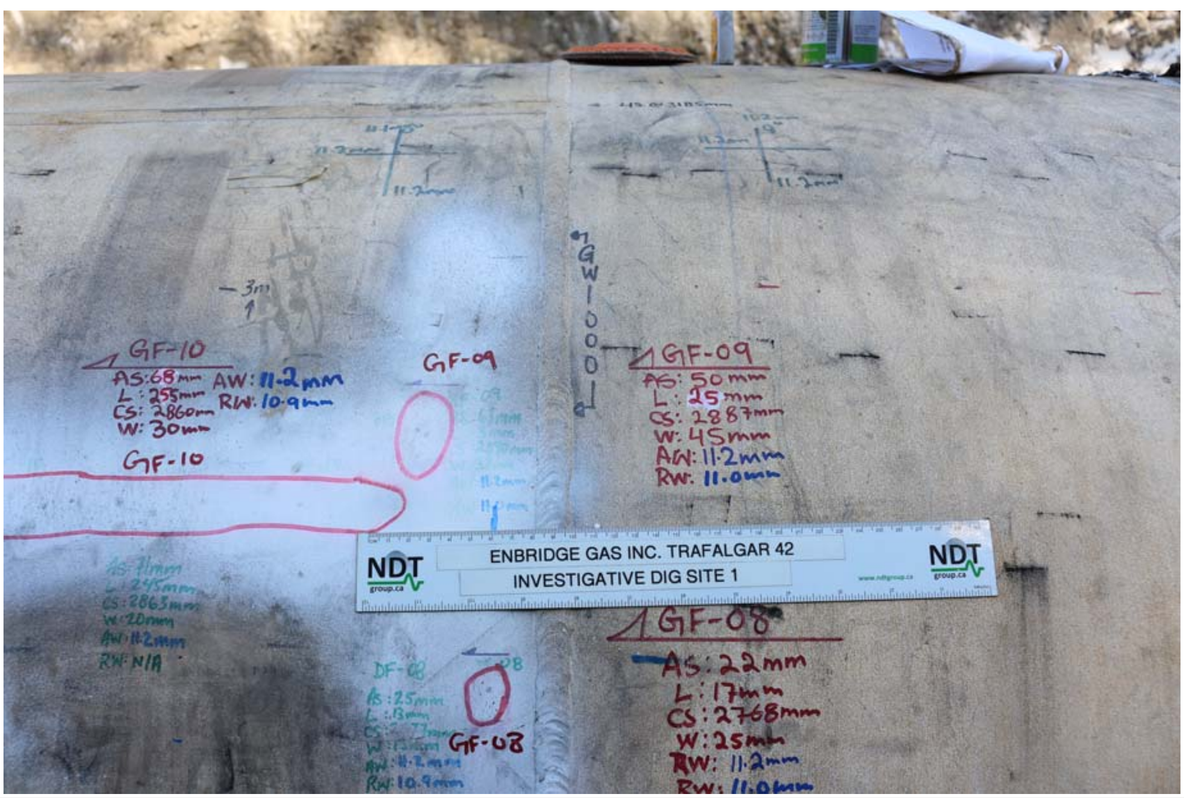


101 - GF-07

ENBRIDGE GAS INC. - TRAFALGAR NPS42

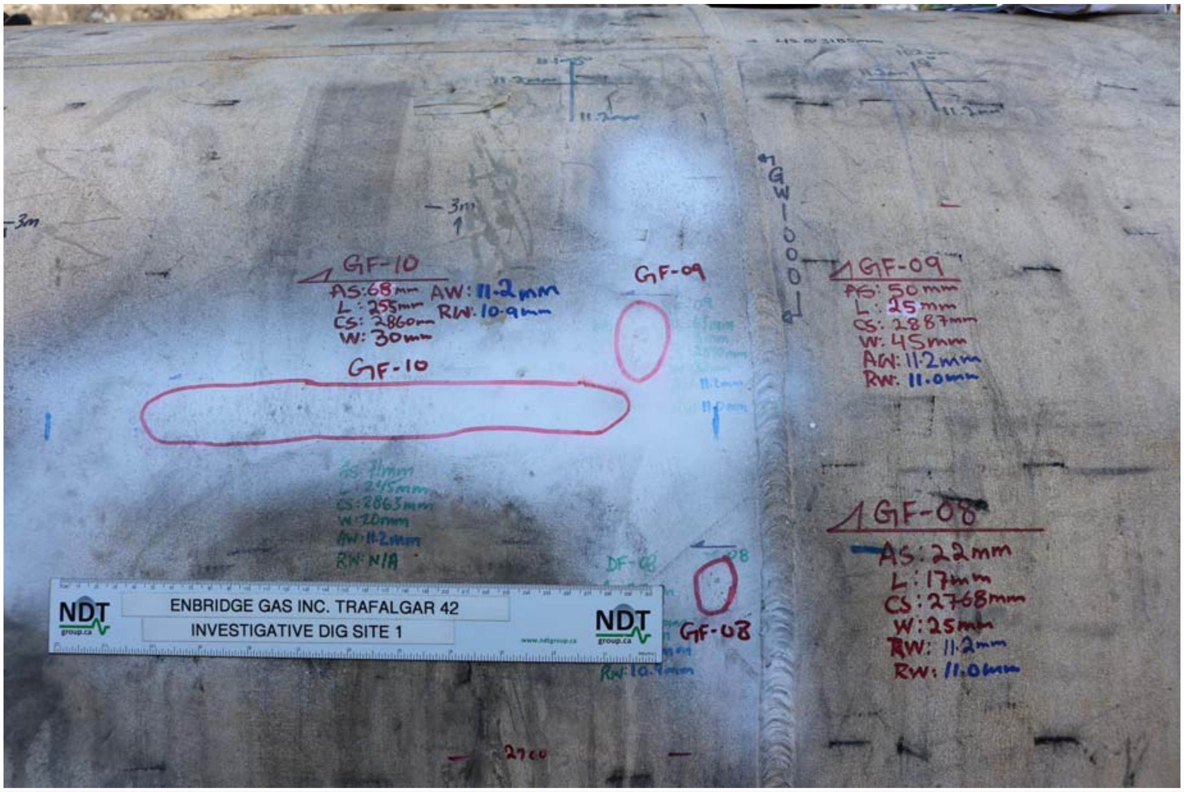


102 - GF-08

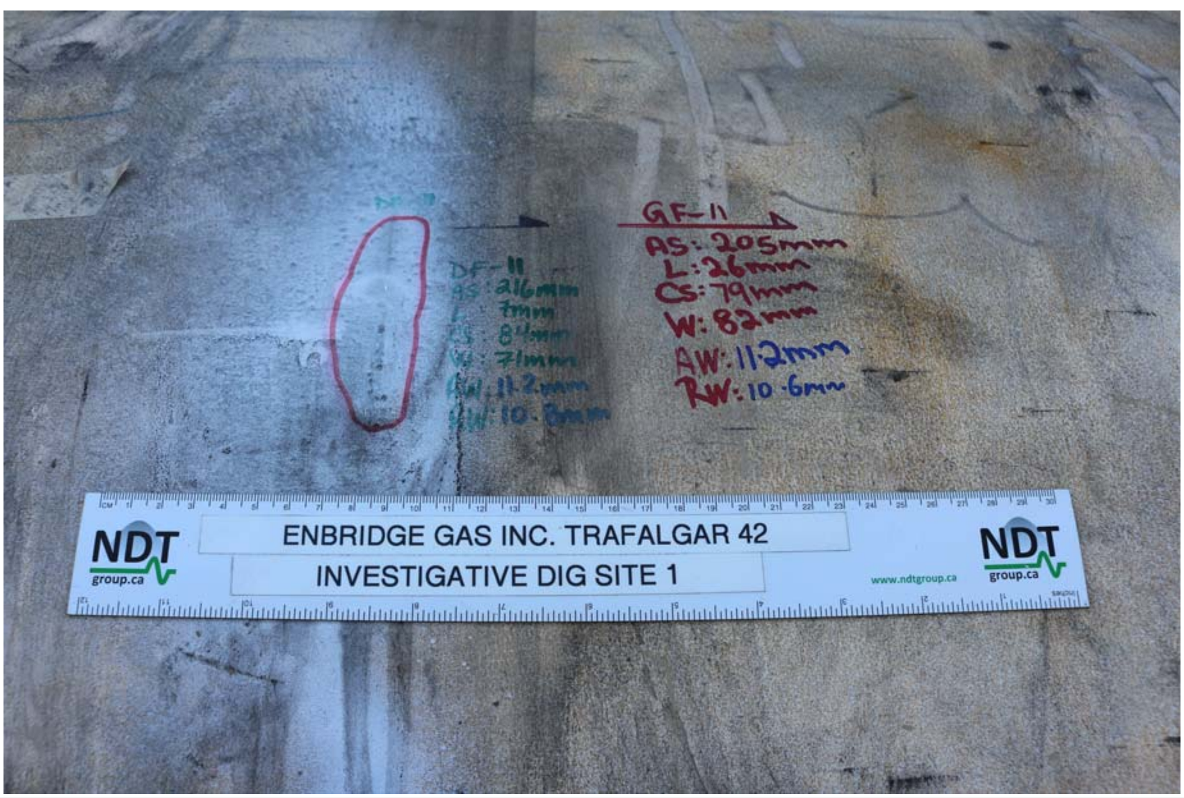


103 - GF-09

ENBRIDGE GAS INC. - TRAFALGAR NPS42

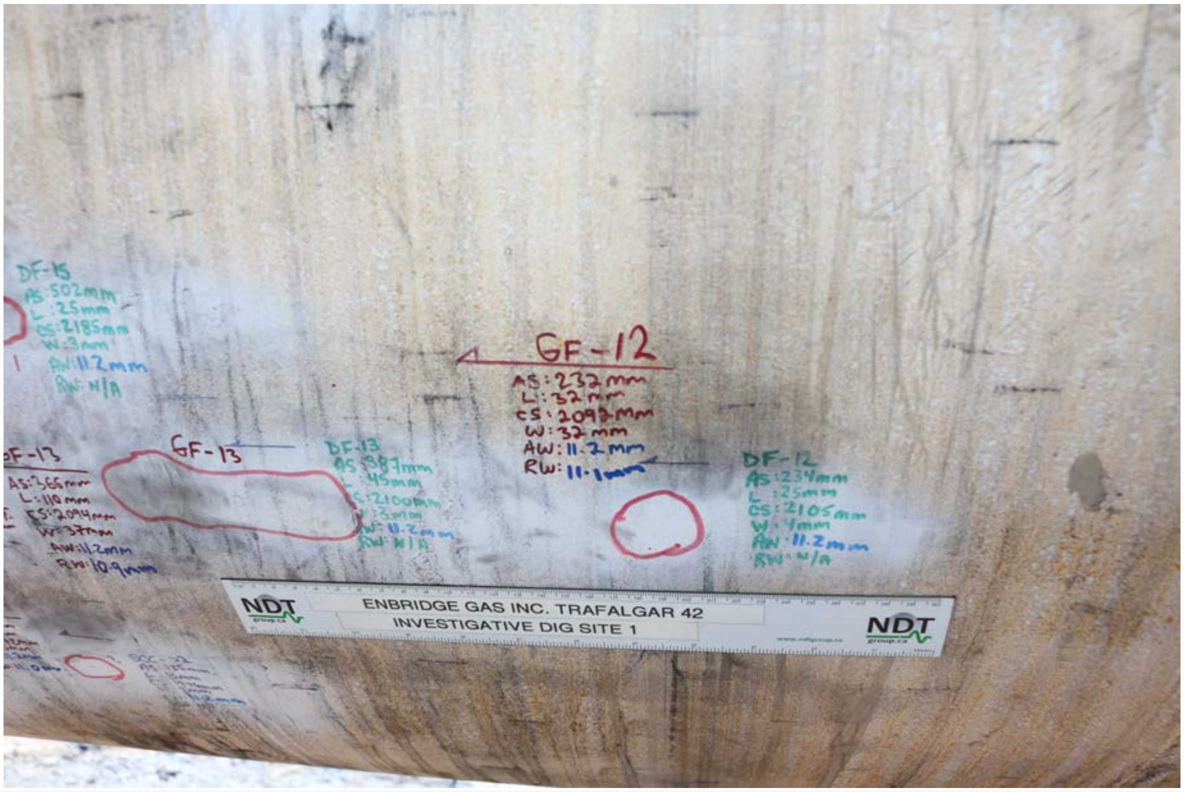


104 - GF-10

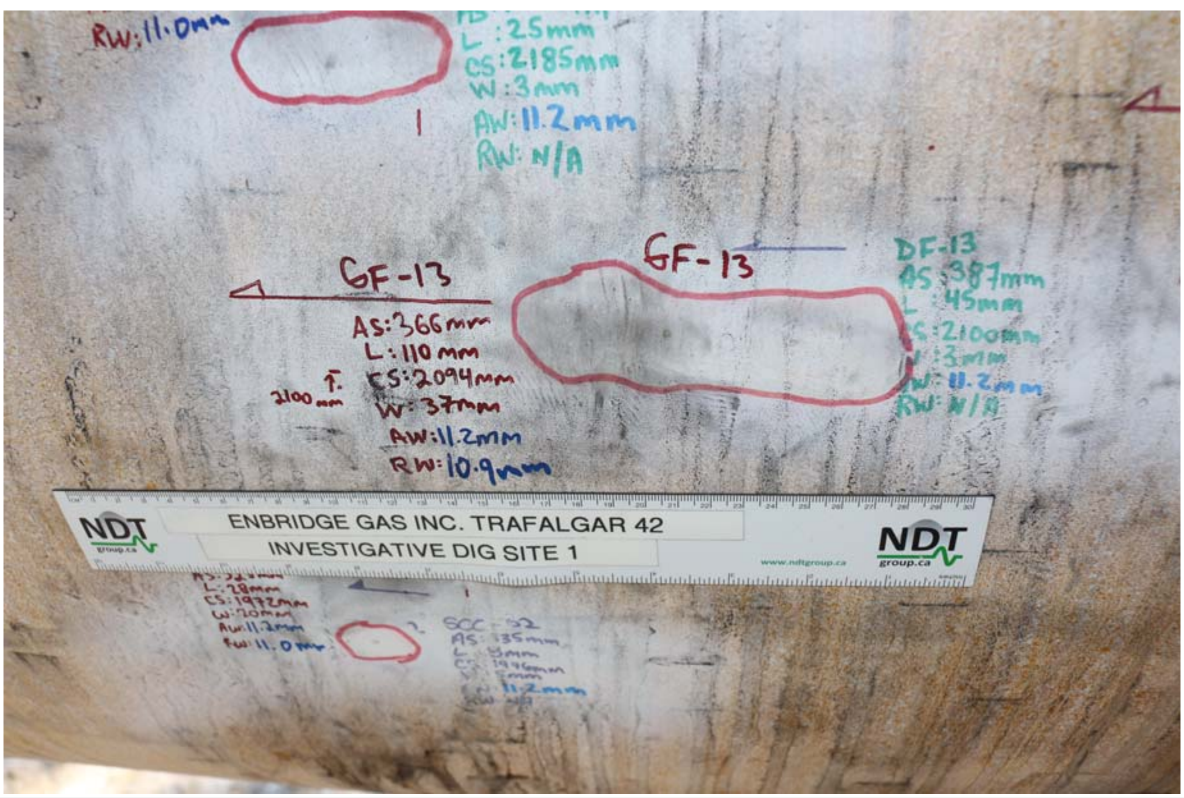


105 - GF-11

ENBRIDGE GAS INC. - TRAFALGAR NPS42



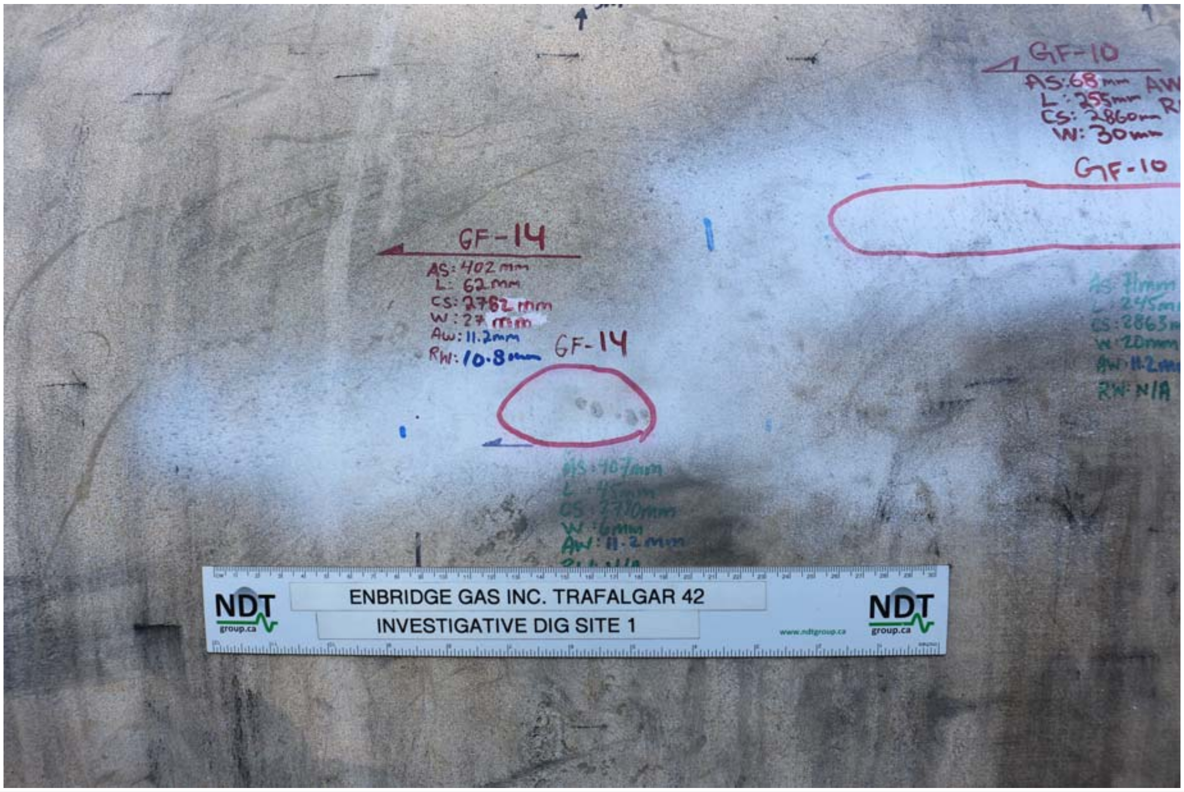
106 - GF-12



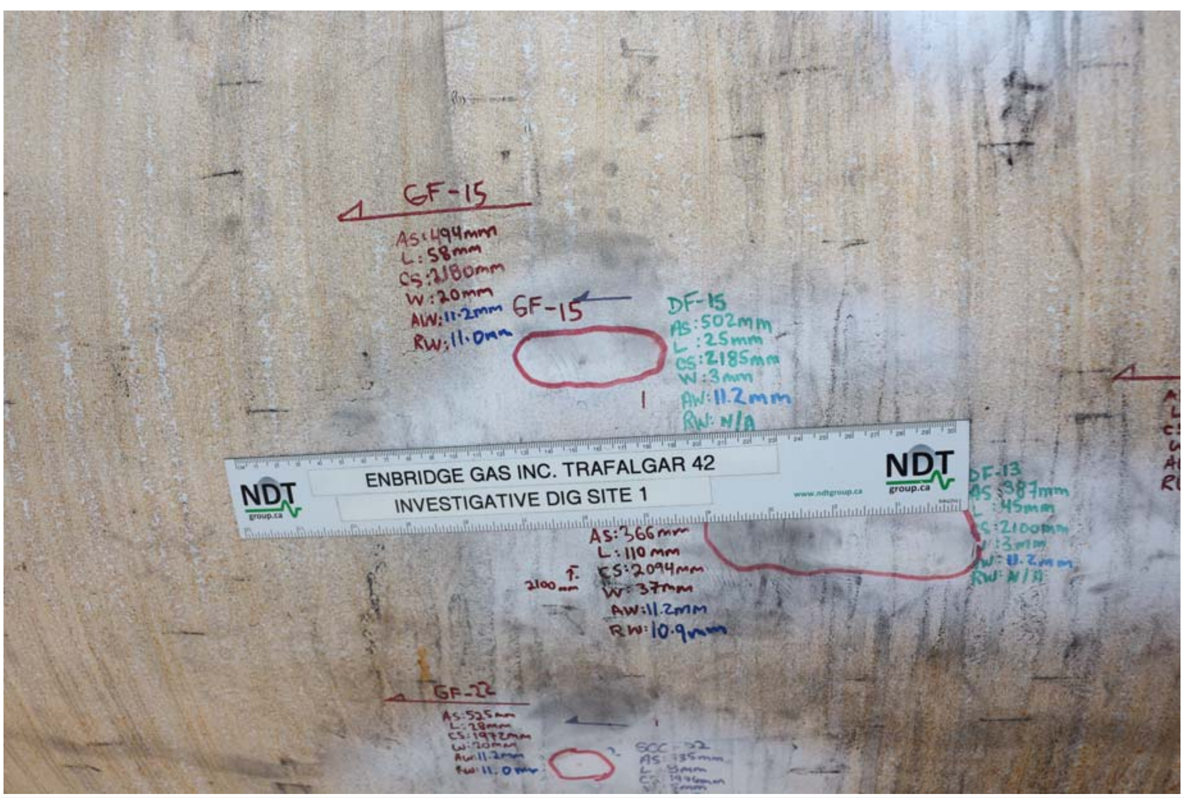
107 - GF-13

NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42

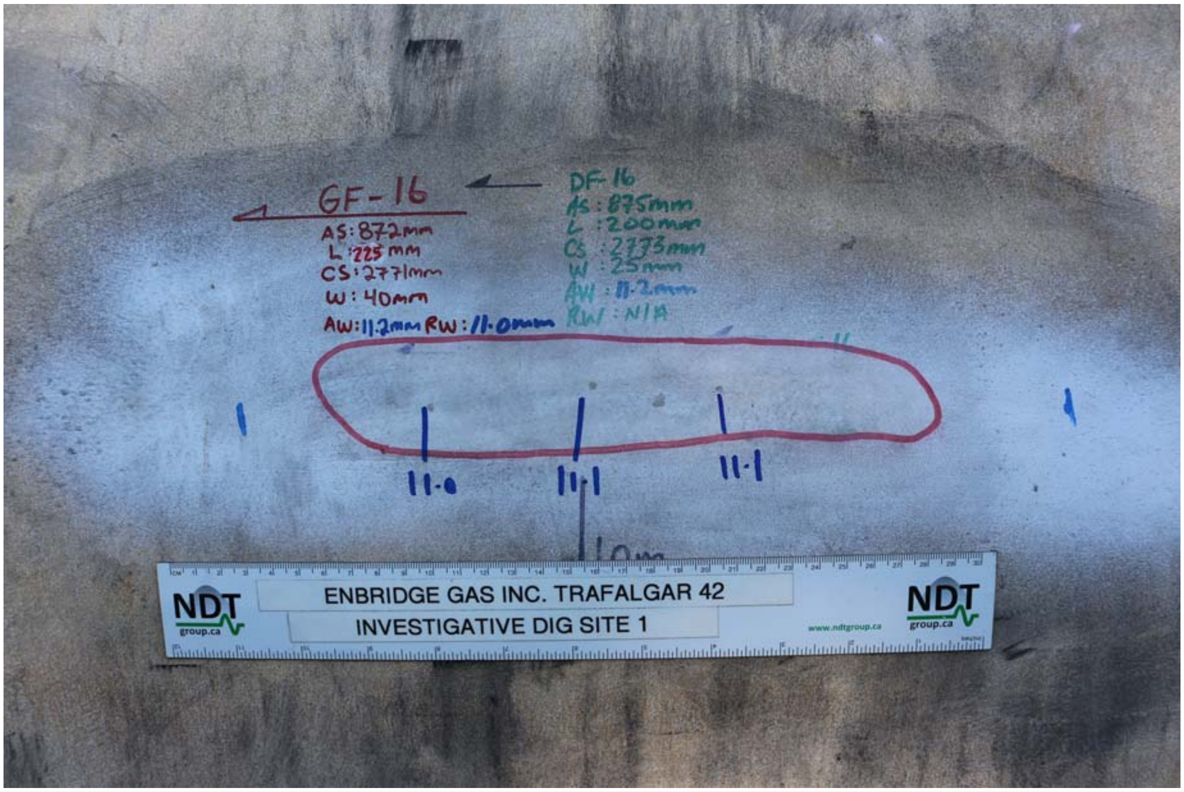


108 - GF-14

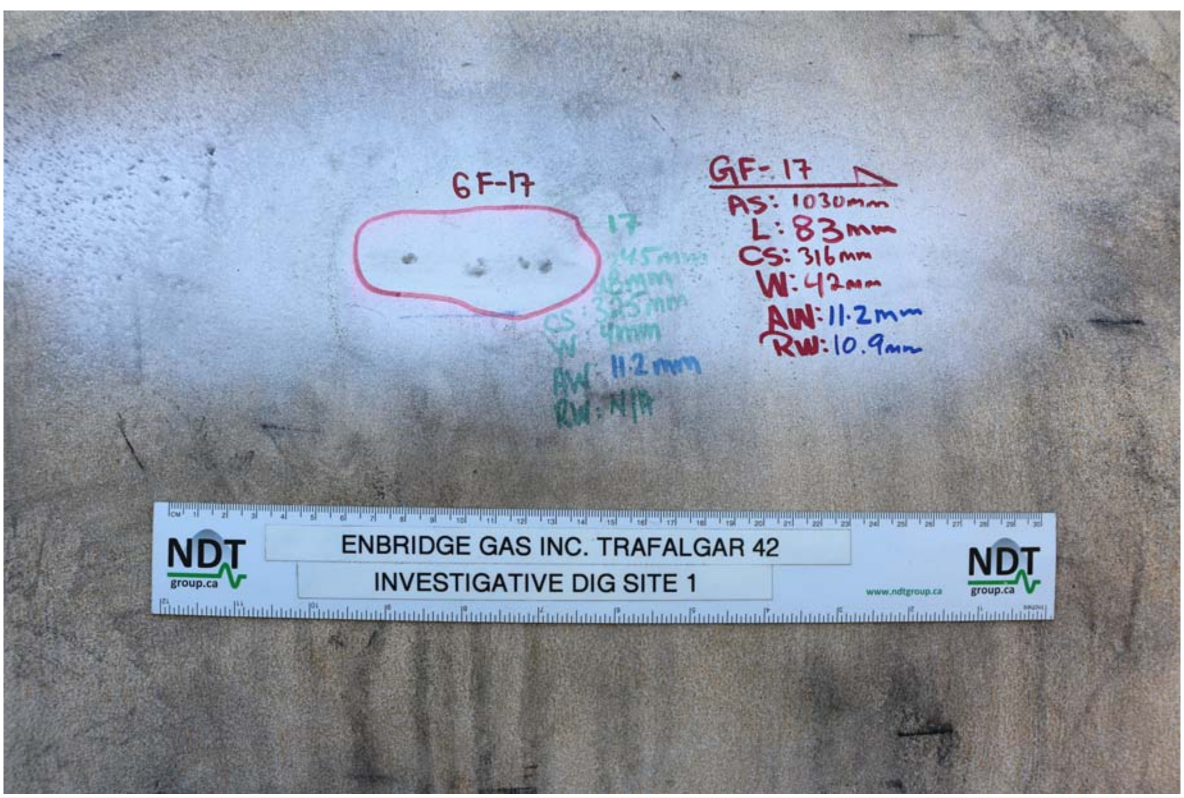


109 - GF-15

ENBRIDGE GAS INC. - TRAFALGAR NPS42

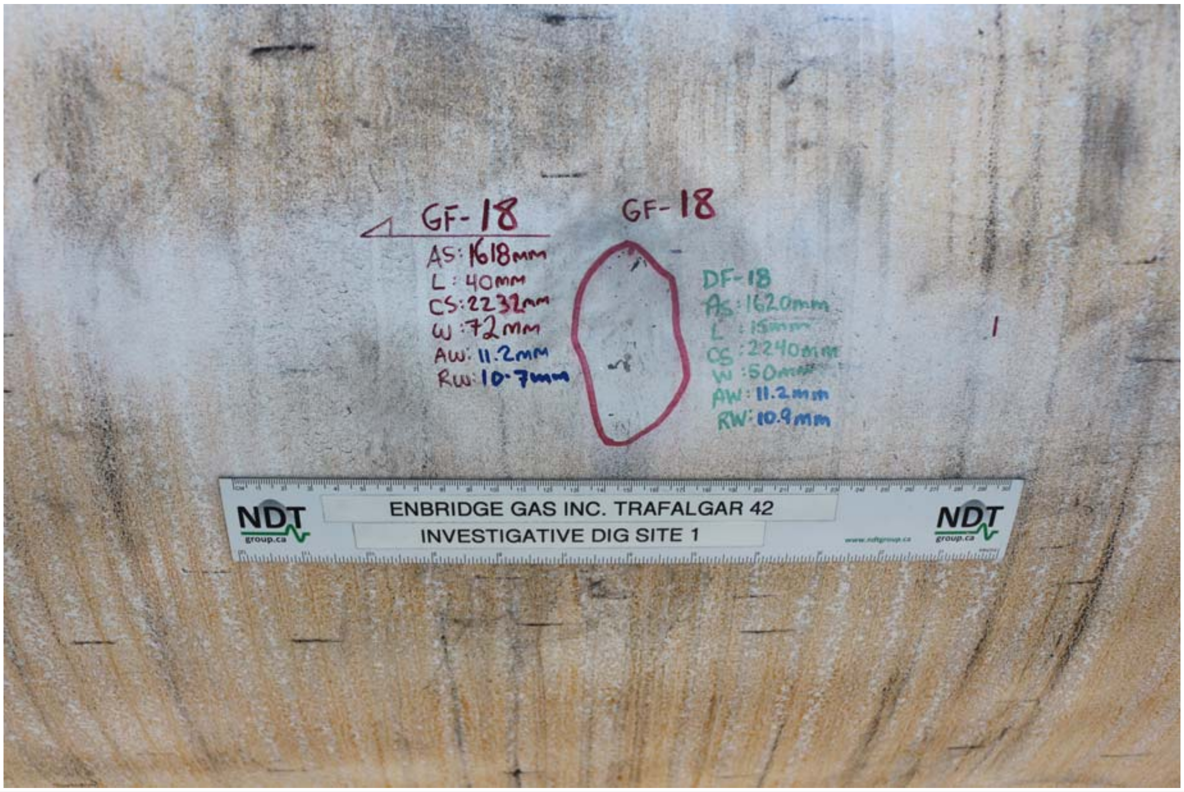


110 - GF-16

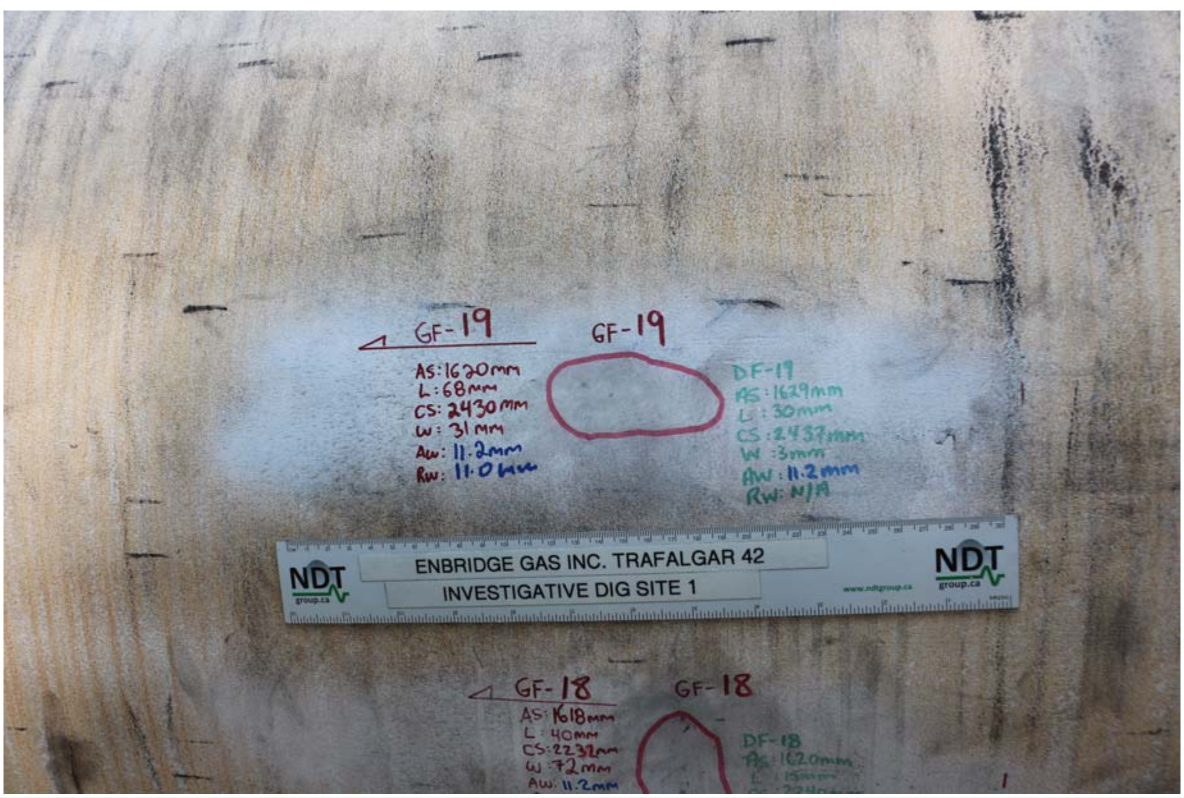


111 - GF-17

ENBRIDGE GAS INC. - TRAFALGAR NPS42

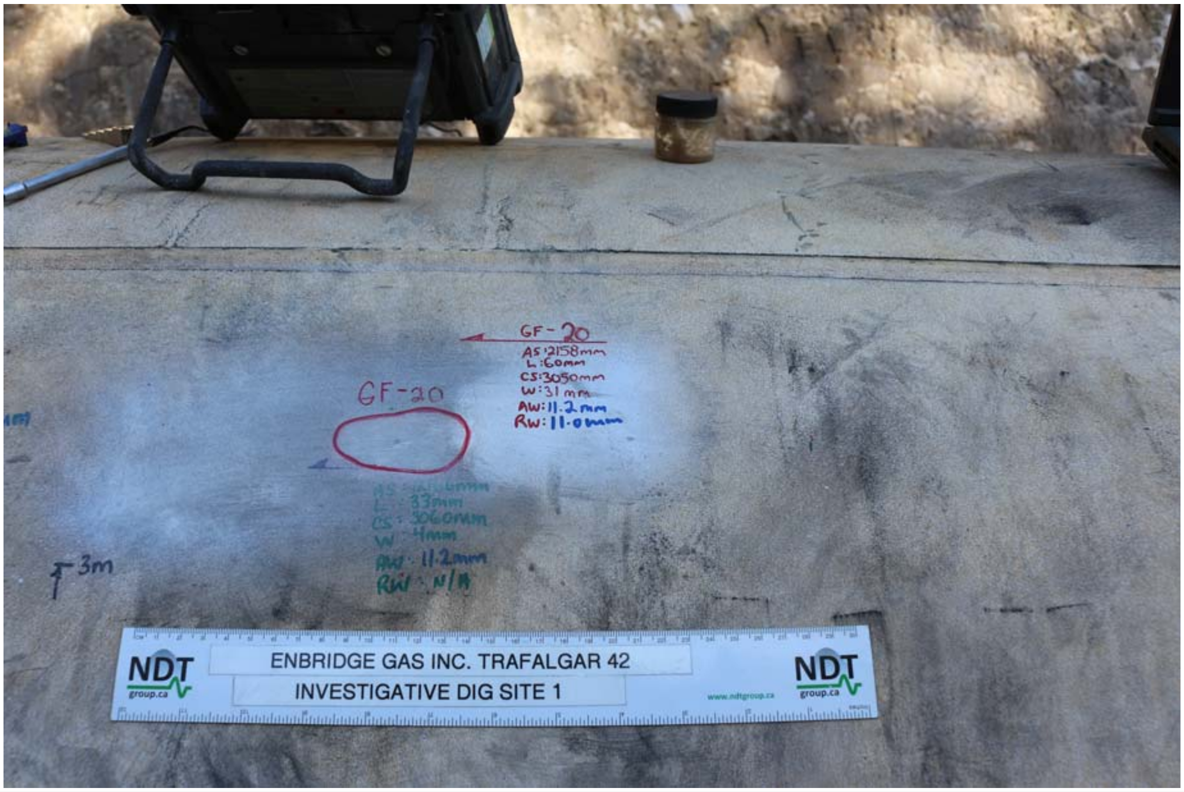


112 - GF-18

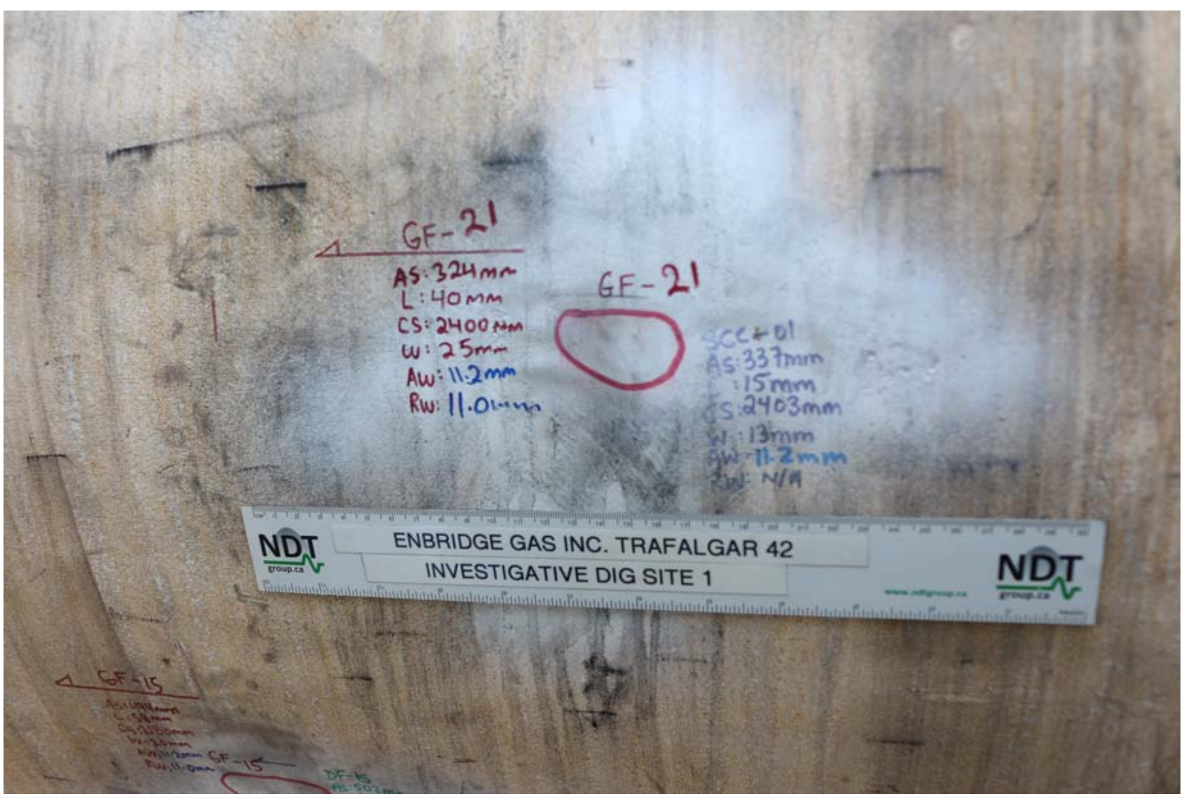


113 - GF-19

ENBRIDGE GAS INC. - TRAFALGAR NPS42

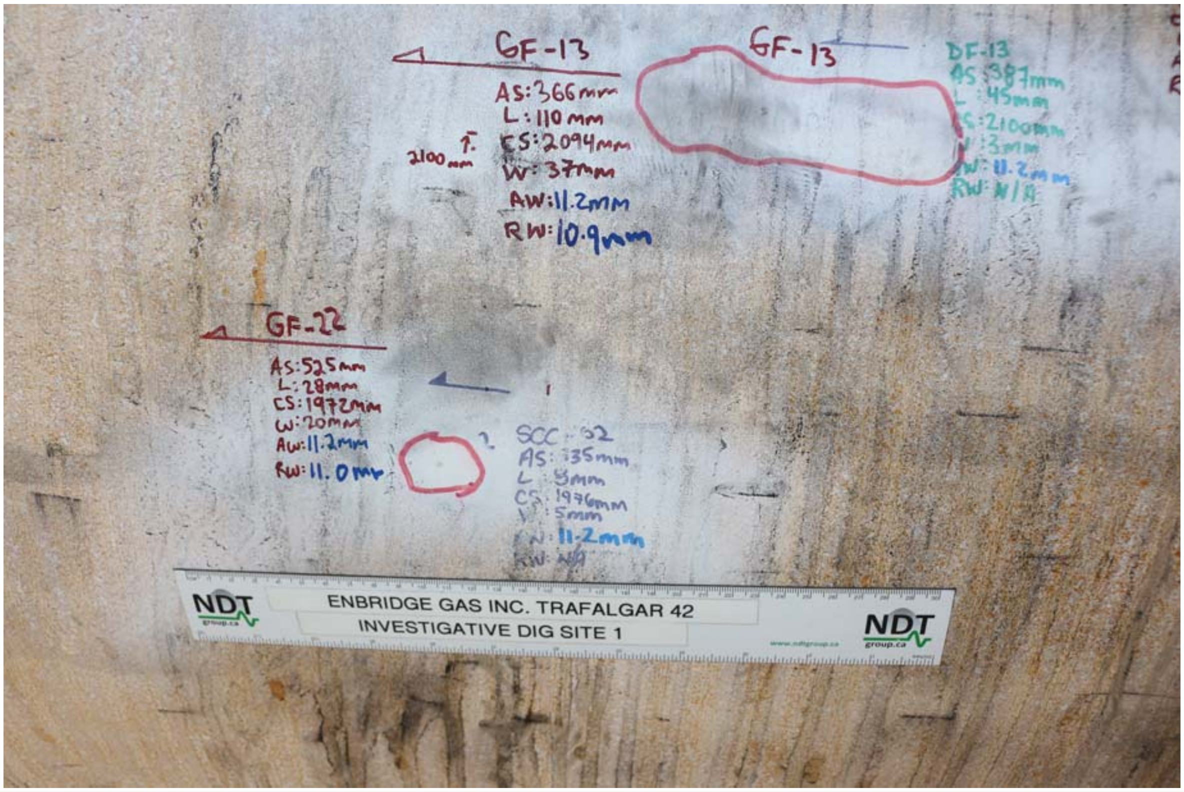


114 - GF-20



115 - GF-21

ENBRIDGE GAS INC. - TRAFALGAR NPS42



116 - GF-22

117 - GF-23

NDT group.ca

NDT Group Inc.
20 Roy Blvd. Unit 30/31
Brantford, ON, Canada
N3R 7K2

Phone: (519) 304-9199
Fax: (519) 304-8199
www.ndtgroup.ca

Pipeline Integrity - Final Report

ENBRIDGE

Enbridge Gas Inc.

Trafalgar NPS42

Investigative Dig Site 2

GWTJ

3012 Bentpath Line

September 20, 2019

Pipeline Integrity Field Report

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Project Information

Project: Trafalgar NPS42
NPS 42
ILI Target: N/A
Dig # or Site Reference: Investigative Dig Site 2
P.O. #: TBA
Ref GW Absolute Dist: N/A

Site Information

Reference GW: TJ
Contractor: Aecon
Year of Construction: N/A
Measurement Ref.: Upstream GW (+)
GPS Co-ordinates: 42.7179720, -82.2117180
Township: Tupperville, ON
Street Address: 3102 Bentpath Line

Pipe Information

Pipe OD (mm): 1066.8
Pipe OD (in): 42
Nominal WT (mm): 11.1
Pipe Grade: 448 (X65)
Design Factor: 0.72
MOP (kPa): 6160
Code/Standard: CSA Z662

ILI Information

ILI Tool Run Date: N/A
ILI Technology: N/A
ILI Tool Vendor: N/A
Reason for Dig: N/A
ILI Target GPS: N/A

Pipe Data

GW Number Exposed	Girth Weld Type	Type of Exposure	ILI Joint Length (m)	Actual Joint Length (m)	LS Type	Predicted LS (Degrees °)	Actual LS (mm)	Actual LS (Clock)	Actual LS (Degrees °)
TJ	N/A	Bell	N/A	N/A	DSAW	N/A	3105.0	11:07	334

Pipe UT Thickness Readings (mm)

Joint Section GW	Upstream U/S				Downstream D/S				Avg. UT Wall Thickness
	0°	90°	180°	270°	0°	90°	180°	270°	
TJ	11.0	11.2	11.1	11.1	11.1	11.2	11.1	11.2	11.13

Cathodic Protection Readings (mV)

Joint Section GW	Upstream U/S		Downstream D/S		Average
	90°	270°	90°	270°	
TJ	N/A	N/A	N/A	N/A	N/A

NGI Technicians:

Name: Simon Susac Certification: CGSB UT2/MT2
Name: Khurram Shahzad Certification: CGSB UT2/MT2

Cert# 13934
Integrity Lead Signature:

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2
Field Report Summary

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Soil, Coating, Groundwater, and Environmental

There was a total of 3 Coating Defect Features identified during coating assessment. CD-01 and CD-03 were identified as intermittent wrinkles on the pipe body at 3:00 and 9:00 respectively. Wrinkles had corrosion deposits underneath coating consisting of a pasty grey color, other wrinkles had corrosion deposits with an appearance of orange/black underneath coating. CD-02 corresponded to tenting along the target joint DSAW long seam weld. Refer to the close-up photos of the corrosion deposits at each coating defect for additional details.

ILI Target Defect

This is an unpiggable line section, no ILI targets available.

Corrosion Assessment Summary:

There was a total of two (2) corrosion features noted in the NDE assessment area. Both corrosion features were in close proximity to the DSAW long seam weld. Neither feature was directly on the long seam. Both corrosion areas are to be recoated, no further repairs are required as per the Enbridge Gas Remediation Report for this site. Site to be recoated.

Metal-Loss Assessment Summary:

There was a total of 12 metal loss features noted in the NDE assessment area. All metal loss areas were existing grinds and did not exceed 3%NWT. All metal loss areas are to be recoated, no further repairs are required as per the Enbridge Gas Remediation Report for this site. Site to be recoated and backfilled.

Mechanical Damage Summary:

There was a total of 55 damage features noted in the NDE assessment area consisting of 11 gouge/scrape features and 44 scabs or scab-like features. These features were all located in the base metal and were not associated with any other feature. No cracking was associated with any of these features. All damage features were successfully removed within the grind limits outlined in the Enbridge Gas Remediation Report for this site. All grind repairs were found acceptable by Enbridge Gas Engineering, site to be coated and backfilled.

Linear Indication Assessment Summary:

None reported.

Dent Summary:

None reported.

SCC Assessment Summary:

None reported.

Grind Assessment Summary:

There was a total of 55 grinds completed to repair 55 damage features as outlined in the Enbridge Gas remediation report for this site. All features were successfully removed at depths of less than 10% and the maximum grind length was 265mm. All grind repairs were found acceptable by Enbridge Gas Engineering, site to be coated and backfilled.

Remediation Summary:

Grind repairs were performed on reported anomalies per client request. No linear indications were detected after final NDE with magnetic particle examination and no localized hard microstructures were noted after 5% Nital Etch. Refer to Grind Summary above and Grind Sheet for further details

Additional Comments:

This dig site assessment was completed as per Enbridge Gas Procedure 'Practice 407 SCC Management'. The dig location was selected by field personnel. No girth weld was available for reference in the excavation. The upstream NDE Start was used as the reference for all axial measurements, the GPS location of the reference is documented in this report. The reference point is referred to as GWTJ for the purposes of this report. Measurement direction was from Cuthbert Station towards Dawn Station as per Enbridge Gas on site personnel. All grind repairs were found acceptable by Enbridge Gas Engineering, no further repairs were required.

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Equipment and Work Scope

Ultrasonic Equipment

Manufacturer: Olympus Epoch 600
Serial #: 130048505
Cal Due: Jan-20
Transducers: FAST, Pencil, FH2E & 45° & 60° Wedges
Type: Single / Dual
Frequency: 5.0MHz / 15MHz /7.5MHz / 5.0MHz
Serial #: 01C0DL / 875731 / 014523 / 834573
UT Calibration Blocks: FAST /MAB / Mini PACS / EDM Block

Advanced UT Equipment

Manufacturer: Olympus OmniScan
Serial #: QC-012700
Cal Due: Jan-20
Transducers: 10L16 N55S Wedge
Type: Linear Array
Frequency: 10 MHz
Serial #: A92393
Calibration Blocks: MAB / Mini PACS / EDM Block

Magnetic Particle Equipment

Manufacturer: Magnaflux Y-1
Serial #: 3840
Cal Due: Feb-20
Paint: Magnaflux WCP-2
Particles: Tiede 616.1
Colour Black
Suspension: Water

Visual Inspection

Calipers	Rulers	5% Nital	Half Cell	Bridge Bar	Profile Gauge
Dial Gauge	30 m Tape	Multi-Meter	pH Paper	4' Level	White Light

Work Scope:

SCOPE	INSPECTION METHODS										
					ULTRASONIC EXAMINATION						
	VT	MT	ACID ETCH	LASER SCAN	UTT	UTCD	UTLAM	PAUT	TOFD	AUT	FLAW SIZING
100% Exposed Pipe:	VT	MT			8 Points						
Long Seam Welds:	VT	MT									
Girth Welds:											
ILI Targets:											
Corrosion/ML:	VT	MT			UT Pen						
Mechanical Damage:	VT	MT			UT Pen		UTLAM				
Arc Burn Assessment:											
Dent/Deformation:											
SCC:											
Grind Repairs General:	VT	MT			UT Pen						
Grind Repairs DF:	VT	MT	ACID ETCH		UT Pen						
Sleeve Landing Areas											
Sleeves - Longitudinal Seams:											
Sleeves - Circumferential Welds:											
Weld Tie In:											
In Service Welding Area:											
Nipple Filled Welds:											

Terms and Conditions

Service Terms and Conditions

The agreement of NDT Group Inc. to perform services extends only to those services provided for in writing. Under no circumstances shall such services extend beyond the performance of the requested services. It is expressly understood that all descriptions comments and expressions of opinion reflect the opinions or observations of NDT Group Inc. based on information and assumptions supplied by the owner/operator and are not intended nor can they be construed as representations or warranties. NDT Group Inc. is not assuming any responsibilities of the owner/operator and the owner/operator retains complete responsibility for the engineering manufacture repair and use decisions as a result of the data or other information provided by NDT Group Inc. In no event shall NDT Group Inc.'s liability in respect of the services referred to herein exceed the amount paid for such services.

Test Methods (NDE and Inspection)

Statements, findings, results and/or reports made or prepared by an employee of NDT Group Inc., including findings about an item meeting or not meeting code, represent the opinion of the employee based on available data at the time of the inspection and shall at all times be subject to inherent limitations of these technologies. NDT Group Inc. cannot be held responsible if employees of Client or another vendor reach different opinions. NDT Group Inc. recommends confirming all such opinions through a second method whenever practicable.

Fitness for Service

Client is responsible for making all repair, recoat, replacement and similar decisions, including decisions based on or regarding inspection/NDE results, remaining strength calculations and Client's procedures for maintenance. Client is responsible for determining the specific remaining strength calculation to be performed (B31G, Modified B31G, RStreng, etc.) and the pipe parameters used for such. NDT Group Inc. cannot be responsible for selecting or making any recommendations regarding the correct calculation method or design factor. When performing calculations, NDT Group Inc's obligation shall be limited to entering data into a calculation and providing the results to Client. NDT Group Inc. does not make any representations regarding the accuracy of the data or the results of the software calculations. Client is responsible for all decisions regarding fitness for service. NDT Group Inc. does not make any representations regarding, and shall not have any liability for, any recommendations, proposed changes, updates and similar statements from NGI's employees regarding Client's in-house integrity programs.

Anomaly Legend

no St Corrosion	GF - Grind Feature	ML - Metal-Loss
D - Dent	ILI - In-Line Inspection	SCC - Stress-Corrosion Cracking
2019-09-20 Damage Feature	LI - Linear Indication	

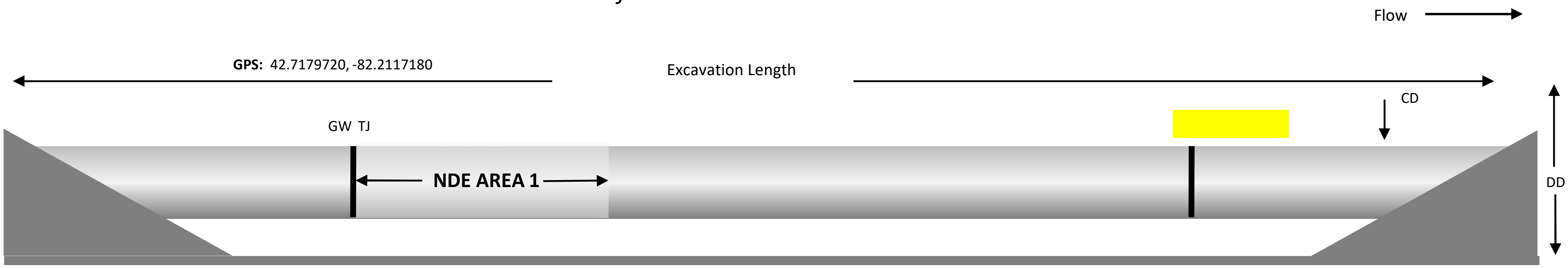
Abbreviations

AUT - Automated Ultrasonic Testing.
AWT - Adjacent UT Wall Thickness
DSAW - Double Submerged Arc Welding
EFW - Electric Flash Weld
ERW - Electric Resistance Weld
FAST UT - Technique for crack detection and sizing.
FCAW - Flux Cored Arc Welding
GMAW - Gas Metal Arc Welding
GTAW - Gas Tungsten Arc Welding
GW - Girth Weld
KPa - Kilopascals
LS - Longitudinal Weld Seam
MOP - Maximum Operating Pressure
MB31.G - Modified B31.G
MT - Magnetic Particle Testing.
MUT - Manual Ultrasonic Testing
NWT - Nominal Wall Thickness
PAUT - Phased Array UT
PSI - Pounds per Square Inch
RPR - Rupture Pressure Ratio
RSTRENG - Remaining Strength Calculation
SAW - Submerged Arc Welding
SCC - Stress-Corrosion Cracking
SMAW - Shielded Metal Arc Welding
ToFD - Time-of-Flight Diffraction
UT - Ultrasonic Testing using contact technique.
UTCD - Ultrasonic crack detection examination
UTLAM - Ultrasonic examination for the detection of internal laminar-type indications.
UTSW - Ultrasonic shear-wave or angle beam examination
UTT - Ultrasonic Thickness Testing
U/S - Upstream
D/S - Downstream

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2
Excavation Information

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ



EXCAVATION DETAILS	
Excavation Length:	13.00 m
Excavation Width:	11.00 m
Cover Depth (CD):	1.50 m
Ditch Depth (DD):	3.20 m
Type of Excavation:	Bell
Exposure Start:	**-1.00 m**
Exposure End:	**4.50 m**
Total Exposure:	**5.50 m**
Reference GW:	TJ

NDE AREA 1	
Reference GW:	TJ
NDE Start:	-0.02 m
NDE End:	2.95 m
NDT Area1 Length:	**2.97 m**
Total Exposure Length:	**5.50 m**

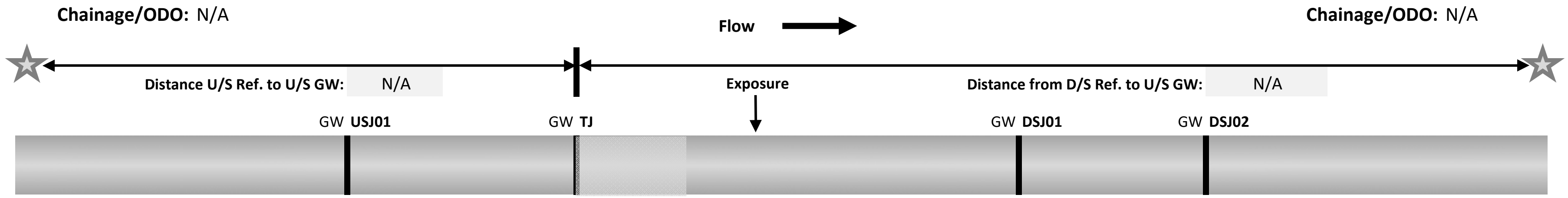
NDE AREA 2	
Reference GW:	
NDE Start:	
NDE End:	
NDT Area2 Length:	**0.00 m**
Total NDE Length:	**2.97 m**

Reference GW:	TJ			
Sag?	☐	Yes	☑	No
Overbend?	☐	Yes	☑	No
Sidebend?	☐	Yes	☑	No
# of Joints Exposed:	1			

AGM & Site Reference Information
(information provided by client)

Upstream Reference	
Reference/AGM:	N/A
Chainage/ODO:	N/A

Downstream Reference	
Reference/AGM:	N/A
Chainage/ODO:	N/A



NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Site Position - Plan View

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2

Soils and Topographical Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Land Use:	Cultivated	Drainage:	Well	Max. Slope:	0%
Site Position:	Level	Gleying:	Not Gleyed (Brown Color Dominates)	Mottling Ambundance:	Few
Topography:	Level	Parent Material:	Lacustrine	Size:	Fine
		Texture:	Clay Loam	Contrast:	Faint

Pipe & Welding Coating Data

Pipe Coating Type:	**Polyethylene Tape**	Pipe Coating Type D/S of NDE Area:	**Polyethylene Tape**	Weld Coating Condition:	**N/A (Comments)**
Pipe Coating Type U/S of NDE Area:	**Polyethylene Tape**	Pipe Coating Condition:	**Fair**	D/S Pipe Coating Condition:	**Fair**
Weld Coating Type:		U/S Pipe Coating Condition:	**Fair**		

Corrosion Deposits

Corrosion Present?	
Colour:	
Texture:	
Magnetic Reaction:	
Carbonate Reaction 10%HCL: (10% HCl Reaction)	
Samples Taken?	

Sampling & Analysis

Type	Sample #	Location	pH	ORP	10% HCL
Soils	SS-01	Bottom of Pipe			
Soils					
Ground Water					
Ground Water					
Electrolyte					
Electrolyte					

Sample No.	2019-09-20	Saturation (%)	TDS (mg/L)	Ca (mg/L)	Cl (mg/L)	Mg (mg/L)	K (mg/L)	Na (mg/L)	SO_4^{2} (mg/L)	CO_3^{-2} (mg/L)	HCO_3 (mg/L)	Alkalinity (mg/L)	10% HCL Reaction
SS-01													

Soil, Coating, Groundwater, and Environmental Comments:

The excavation was located on level ground in a soy bean field. During excavation the side walls consisted of dominantly brown soil(not gleyed) and texture was primarily identified as clay loam. No ground water was noted in the excavation. No electrolytes were identified during coating assessment. For details regarding corrosion deposits refer to coating damage page. A soil sample was collected at 4 O'Clock of the pipe and will be summitted for analysis if required by Enbridge Gas Engineering.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line

Investigative Dig Site 2

Coating Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Coating Feature Number	Type of Damage	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Comments
CD-01	Wrinkle	TJ	0	3000	3000	500	900	400	1:47	3:13	54°	97°	Wrinkle on pipe body 3:00 side
CD-02	Tenting	TJ	0	3000	3000	3000	3250	250	10:44	11:38	349°	349°	Tenting along target Joint DSAW long seam weld
CD-03	Wrinkle	TJ	0	3000	3000	2300	2800	500	8:14	10:01	301°	301°	Wrinkle on pipe body 9:00 side

Coating Assessment Comments:

There was a total of 3 Coating Defect Features identified during coating assessment. CD-01 and CD-03 were identified as intermittent wrinkles on the pipe body at 3:00 and 9:00 respectively. Wrinkles had corrosion deposits underneath coating consisting of a pasty grey color, other wrinkles had corrosion deposits with an appearance of orange/black underneath coating. CD-02 corresponded to tenting along the target joint DSAW long seam weld. Refer to the close-up photos of the corrosion deposits at each coating defect for additional details.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2

Corrosion Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Feature Number	Location	ILI Feature Number	Target Predicted Depth (%)	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Circ Start (°)	Circ End (°)	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	On or Near Weld (within 12.7mm)	MB31.G Burst Pressure (kPa)	Repair Details
COR-01	External			TJ	247	272	25	3074	3086	12	11:00	11:02	330°	331°	10.0	11.1	1.1	9.9%	9.9%	Yes	10742	Recoat
COR-02	External			TJ	2038	2098	60	3070	3090	20	10:59	11:03	330°	332°	10.1	11.1	1.0	9.0%	9.0%	Yes	10684	Recoat

* AWT - Actual UT Wall Thickness

Interaction Rules: **6T**

Corrosion Assessment Comments:

There was a total of two (2) corrosion features noted in the NDE assessment area. Both corrosion features were in close proximity to the DSAW long seam weld. Neither feature was directly on the long seam. Both corrosion areas are to be recoated, no further repairs are required as per the Enbridge Gas Remediation Report for this site. Site to be recoated.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2

Mechanical Damage Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Feature Number	Type of Damage	ILI Feature Number	Target Predicted Depth (%)	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Circ Start (°)	Circ End (°)	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	On or Near Weld (within 12.7mm)	MB31.G Burst Pressure (kPa)	Grind Repaired?	Repair Details
DF-01	Scab			TJ	-26	4	30	1552	1562	10	5:33	5:35	167°	168°		11.2				No		Yes	Removed
DF-02	Gouge / Scrape			TJ	2	82	80	931	966	35	3:20	3:27	100°	104°	11.0	11.1	0.1	1%	0.9%	No	10746	Yes	Removed
DF-03	Scab			TJ	0	15	15	1355	1365	10	4:51	4:53	146°	147°		11.2				No		Yes	Removed
DF-04	Scab			TJ	15	25	10	1890	1956	66	6:46	7:00	203°	210°		11.2				No		Yes	Removed
DF-05	Scab			TJ	36	50	14	2588	2593	5	9:15	9:17	278°	279°		11.2				No		Yes	Removed
DF-06	Gouge / Scrape			TJ	50	65	15	1652	1714	62	5:54	6:08	177°	184°	11.0	11.1	0.1	1%	0.9%	No	10757	Yes	Removed
DF-07	Scab			TJ	75	97	22	1488	1498	10	5:19	5:21	160°	161°		11.2				No		Yes	Removed
DF-08	Gouge / Scrape			TJ	85	92	7	583	705	122	2:05	2:31	63°	76°	11.0	11.2	0.2	2%	0.9%	No	10758	Yes	Removed
DF-09	Scab			TJ	190	262	72	1495	1513	18	5:21	5:25	161°	163°		11.2				No		Yes	Removed
DF-10	Scab			TJ	245	261	16	2695	2700	5	9:38	9:40	289°	290°		11.2				No		Yes	Removed
DF-11	Scab			TJ	250	380	130	1905	1950	45	6:49	6:58	205°	209°		11.1				No		Yes	Removed
DF-12	Scab			TJ	255	310	55	2420	2430	10	8:39	8:42	260°	261°		11.1				No		Yes	Removed
DF-13	Scab			TJ	312	344	32	1510	1545	35	5:24	5:31	162°	166°		11.1				No		Yes	Removed
DF-14	Scab			TJ	388	398	10	1028	1033	5	3:40	3:41	110°	111°		11.1				No		Yes	Removed
DF-15	Scab			TJ	442	538	96	1508	1533	25	5:23	5:29	162°	165°		11.1				No		Yes	Removed
DF-16	Gouge / Scrape			TJ	472	482	10	1018	1058	40	3:38	3:47	109°	114°	10.9	11.1	0.2	2%	1.8%	No	10757	Yes	Removed
DF-17	Scab			TJ	480	502	22	2433	2452	19	8:42	8:46	261°	263°		11.1				No		Yes	Removed
DF-18	Scab			TJ	564	584	20	2680	2685	5	9:35	9:36	288°	288°		11.1				No		Yes	Removed
DF-19	Scab			TJ	610	655	45	2575	2585	10	9:13	9:15	277°	278°		11.1				No		Yes	Removed
DF-20	Gouge / Scrape			TJ	764	779	15	615	626	11	2:12	2:14	66°	67°	10.9	11.1	0.2	2%	1.8%	No	10757	Yes	Removed

* AWT - Actual UT Wall Thickness, Replac. - Replacement, P. - Partially, P. Sleev/Remov - Partially Sleeved & Partially Removed

Mechanical Damage Comments:

There was a total of 55 damage features noted in the NDE assessment area consisting of 11 gouge/scrape features and 44 scabs or scab-like features. These features were all located in the base metal and were not associated with any other feature. No cracking was associated with any of these features. All damage features were successfully removed within the grind limits outlined in the Enbridge Gas Remediation Report for this site. All grind repairs were found acceptable by Enbridge Gas Engineering, site to be coated and backfilled.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Mechanical Damage Assessment

Feature Number	Type of Damage	ILI Feature Number	Target Predicted Depth (%)	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Circ Start (°)	Circ End (°)	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	On or Near Weld (within 12.7mm)	MB31.G Burst Pressure (kPa)	Grind Repaired?	Repair Details
DF-21	Scab			TJ	772	823	51	1412	1457	45	5:03	5:13	152°	157°		11.2				No		Yes	Removed
DF-22	Gouge / Scrape			TJ	784	799	15	720	728	8	2:34	2:36	77°	78°	11.0	11.2	0.2	2%	0.9%	No	10757	Yes	Removed
DF-23	Gouge / Scrape			TJ	785	850	65	482	522	40	1:43	1:52	52°	56°	11.0	11.2	0.2	2%	0.9%	No	10750	Yes	Removed
DF-24	Gouge / Scrape			TJ	795	800	5	1352	1379	27	4:50	4:56	145°	148°		11.2				No		Yes	Removed
DF-25	Gouge / Scrape			TJ	1065	1077	12	2070	2125	55	7:24	7:36	222°	228°	11.0	11.2	0.2	2%	0.9%	No	10757	Yes	Removed
DF-26	Scab			TJ	1115	1135	20	2200	2206	6	7:52	7:53	236°	237°		11.2				No		Yes	Removed
DF-27	Scab			TJ	1125	1155	30	460	468	8	1:38	1:40	49°	50°		11.2				No		Yes	Removed
DF-28	Scab			TJ	1250	1270	20	2461	2469	8	8:48	8:50	264°	265°		11.1				No		Yes	Removed
DF-29	Scab			TJ	1315	1343	28	1205	1210	5	4:18	4:19	129°	130°		11.1				No		Yes	Removed
DF-30	Scab			TJ	1352	1384	32	1404	1411	7	5:01	5:03	151°	152°		11.2				No		Yes	Removed
DF-31	Scab			TJ	1362	1392	30	2003	2008	5	7:10	7:11	215°	216°		11.2				No		Yes	Removed
DF-32	Scab			TJ	1375	1431	56	2170	2180	10	7:46	7:48	233°	234°		11.2				No		Yes	Removed
DF-33	Scab			TJ	1580	1734	154	1585	1620	35	5:40	5:48	170°	174°		11.1				No		Yes	Removed
DF-34	Scab			TJ	1645	1890	245	2105	2149	44	7:32	7:41	226°	231°		11.1				No		Yes	Removed
DF-35	Scab			TJ	1645	1679	34	1255	1262	7	4:29	4:31	135°	136°		11.1				No		Yes	Removed
DF-36	Scab			TJ	1880	1907	27	1770	1775	5	6:20	6:21	190°	191°		11.2				No		Yes	Removed
DF-37	Scab			TJ	1920	1955	35	2330	2340	10	8:20	8:22	250°	251°		11.2				No		Yes	Removed
DF-38	Scab			TJ	2000	2048	48	2225	2242	17	7:58	8:01	239°	241°		11.2				No		Yes	Removed
DF-39	Scab			TJ	2035	2047	12	2506	2511	5	8:58	8:59	269°	270°		11.1				No		Yes	Removed
DF-40	Scab			TJ	2075	2112	37	2505	2512	7	8:58	8:59	269°	270°		11.2				No		Yes	Removed

* AWT - Actual UT Wall Thickness, Replac. - Replacement, P. - Partially, P. Sleev/Remov - Partially Sleeved & Partially Removed

Mechanical Damage Comments:

Refer to comments on first Mechanical Damage page.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2

Mechanical Damage Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Feature Number	Type of Damage	ILI Feature Number	Target Predicted Depth (%)	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Circ Start (°)	Circ End (°)	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	On or Near Weld (within 12.7mm)	MB31.G Burst Pressure (kPa)	Grind Repaired?	Repair Details
DF-41	Gouge / Scrape			TJ	2080	2086	6	495	515	20	1:46	1:50	53°	55°	11.1	11.2	0.1	1%	0.0%	No	10758	Yes	Removed
DF-42	Scab			TJ	2213	2239	26	1240	1250	10	4:26	4:28	133°	134°		11.2				No		Yes	Removed
DF-43	Scab			TJ	2267	2317	50	1025	1035	10	3:40	3:42	110°	111°		11.1				No		Yes	Removed
DF-44	Gouge / Scrape			TJ	2284	2299	15	1740	1788	48	6:13	6:24	187°	192°	11.0	11.2	0.2	2%	0.9%	No	10757	Yes	Removed
DF-45	Scab			TJ	2310	2327	17	2280	2284	4	8:09	8:10	245°	245°		11.2				No		Yes	Removed
DF-46	Scab			TJ	2380	2465	85	1110	1122	12	3:58	4:01	119°	121°		11.2				No		Yes	Removed
DF-47	Scab			TJ	2558	2590	32	1978	1988	10	7:04	7:07	212°	214°		11.1				No		Yes	Removed
DF-48	Scab			TJ	2575	2597	22	2509	2513	4	8:59	8:59	270°	270°		11.2				No		Yes	Removed
DF-49	Scab			TJ	2625	2645	20	2250	2254	4	8:03	8:04	242°	242°		11.2				No		Yes	Removed
DF-50	Scab			TJ	2640	2685	45	1375	1385	10	4:55	4:57	148°	149°		11.2				No		Yes	Removed
DF-51	Scab			TJ	2698	2790	92	1965	1990	25	7:02	7:07	211°	214°		11.2				No		Yes	Removed
DF-52	Scab			TJ	2796	2858	62	2254	2265	11	8:04	8:06	242°	243°		11.2				No		Yes	Removed
DF-53	Scab			TJ	2810	2837	27	930	939	9	3:19	3:21	100°	101°		11.2				No		Yes	Removed
DF-54	Scab			TJ	2912	2950	38	1515	1523	8	5:25	5:27	163°	164°		11.1				No		Yes	Removed
DF-55	Scab			TJ	2925	2943	18	1125	1131	6	4:01	4:02	121°	121°		11.2				No		Yes	Removed

* AWT - Actual UT Wall Thickness, Replac. - Replacement, P. - Partially, P. Sleev/Remov - Partially Sleeved & Partially Removed

Mechanical Damage Comments:

Refer to comments on first Mechanical Damage page.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line

Investigative Dig Site 2

Metal-Loss Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Feature Number	Location	ILI Feature Number	Target Predicted Depth (%)	Associated Features	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Circ Start (°)	Circ End (°)	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	On or Near Weld (within 12.7mm)	MB31.G Burst Pressure (kPa)	Repair Details
ML-01	External				TJ	-27	78	105	1485	1537	52	5:19	5:30	160°	165°	11.0	11.2	0.2	2%	0.9%	No	10741	Recoat
ML-02	External				TJ	-20	171	191	1305	1410	105	4:40	5:02	140°	151°	11.1	11.2	0.1	1%	0.0%	No	10758	Recoat
ML-03	External				TJ	95	169	74	1422	1447	25	5:05	5:10	153°	155°	11.0	11.2	0.2	2%	0.9%	No	10748	Recoat
ML-04	External				TJ	317	398	81	2112	2182	70	7:33	7:48	227°	234°	11.1	11.2	0.1	1%	0.0%	No	10758	Recoat
ML-05	External				TJ	350	437	87	1482	1512	30	5:18	5:24	159°	162°	11.1	11.2	0.1	1%	0.0%	No	10758	Recoat
ML-06	External				TJ	1415	1555	140	960	1060	100	3:26	3:47	103°	114°	10.9	11.2	0.3	3%	1.8%	No	10708	Recoat
ML-07	External				TJ	1557	1698	141	2195	2227	32	7:51	7:58	236°	239°	10.9	11.2	0.3	3%	1.8%	No	10708	Recoat
ML-08	External				TJ	2277	2368	91	980	1045	65	3:30	3:44	105°	112°	11.0	11.2	0.2	2%	0.9%	No	10744	Recoat
ML-09	External				TJ	2460	2565	105	946	1011	65	3:23	3:37	102°	109°	11.0	11.2	0.2	2%	0.9%	No	10741	Recoat
ML-10	External				TJ	2460	2592	132	2390	2443	53	8:33	8:44	257°	262°	10.9	11.2	0.3	3%	1.8%	No	10711	Recoat
ML-11	External				TJ	2782	2984	202	2175	2206	31	7:47	7:53	234°	237°	11.0	11.2	0.2	2%	0.9%	No	10722	Recoat
ML-12	External				TJ	1220	1370	150	2485	2510	25	8:53	8:59	267°	270°	11.0	11.2	0.2	2%	0.9%	No	10731	Recoat

* AWT - Actual UT Wall Thickness, P. - Partially

Interaction Rules: **6T**

Metal-Loss Assessment Comments:

There was a total of 12 metal loss features noted in the NDE assessment area. All metal loss areas were existing grinds and did not exceed 3%NWT. All metal loss areas are to be recoated, no further repairs are required as per the Enbridge Gas Remediation Report for this site. Site to be recoated and backfilled.

NDT group.ca

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line

Investigative Dig Site 2

Grind Repair Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Feature Number	Repaired Features	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	Grind Repaired?	MB31.G Burst Pressure (kPa)	Repair Details
GF-01	DF-01	TJ	-37	8	45	1550	1575	25	5:32	5:38	166°	169°	10.9	11.2	0.3	3%	1.8%	Yes	10749	Recoat
GF-02	DF-02	TJ	-7	88	95	923	973	50	3:18	3:29	99°	105°	10.8	11.1	0.3	3%	2.7%	Yes	10713	Recoat
GF-03	DF-03	TJ	-8	20	28	1348	1368	20	4:49	4:53	145°	147°	10.9	11.2	0.3	3%	1.8%	Yes	10754	Recoat
GF-04	DF-04	TJ	-20	130	150	1883	1958	75	6:44	7:00	202°	210°	10.9	11.2	0.3	3%	1.8%	Yes	10704	Recoat
GF-05	DF-05	TJ	31	64	33	2581	2602	21	9:14	9:19	277°	279°	10.9	11.2	0.3	3%	1.8%	Yes	10753	Recoat
GF-06	DF-06	TJ	46	68	22	1642	1724	82	5:52	6:10	176°	185°	10.8	11.1	0.3	3%	2.7%	Yes	10754	Recoat
GF-07	DF-07	TJ	67	122	55	1480	1505	25	5:17	5:23	159°	162°	10.9	11.2	0.3	3%	1.8%	Yes	10746	Recoat
GF-08	DF-08	TJ	78	108	30	570	714	144	2:02	2:33	61°	77°	10.9	11.2	0.3	3%	1.8%	Yes	10754	Recoat
GF-09	DF-09	TJ	160	285	125	1485	1515	30	5:19	5:25	160°	163°	10.9	11.2	0.3	3%	1.8%	Yes	10714	Recoat
GF-10	DF-10	TJ	240	268	28	2685	2707	22	9:36	9:41	288°	291°	10.9	11.2	0.3	3%	1.8%	Yes	10754	Recoat
GF-11	DF-11	TJ	239	386	147	1894	1958	64	6:46	7:00	203°	210°	10.9	11.1	0.2	2%	1.8%	Yes	10705	Recoat
GF-12	DF-12	TJ	248	315	67	2417	2437	20	8:39	8:43	260°	262°	10.9	11.1	0.2	2%	1.8%	Yes	10741	Recoat
GF-13	DF-13	TJ	300	365	65	1505	1555	50	5:23	5:34	162°	167°	10.8	11.1	0.3	3%	2.7%	Yes	10733	Recoat
GF-14	DF-14	TJ	363	424	61	1015	1041	26	3:38	3:43	109°	112°	10.7	11.1	0.4	4%	3.6%	Yes	10729	Recoat
GF-15	DF-15	TJ	435	540	105	1500	1535	35	5:22	5:29	161°	165°	10.9	11.1	0.2	2%	1.8%	Yes	10724	Recoat
GF-16	DF-16	TJ	464	494	30	1016	1060	44	3:38	3:47	109°	114°	10.9	11.1	0.2	2%	1.8%	Yes	10754	Recoat
GF-17	DF-17	TJ	473	509	36	2424	2462	38	8:40	8:48	260°	264°	10.9	11.1	0.2	2%	1.8%	Yes	10752	Recoat
GF-18	DF-18	TJ	558	597	39	2668	2691	23	9:33	9:38	287°	289°	10.9	11.1	0.2	2%	1.8%	Yes	10751	Recoat
GF-19	DF-19	TJ	593	668	75	2560	2598	38	9:09	9:18	275°	279°	10.8	11.1	0.3	3%	2.7%	Yes	10727	Recoat
GF-20	DF-20	TJ	755	789	34	610	631	21	2:11	2:15	66°	68°	10.8	11.1	0.3	3%	2.7%	Yes	10750	Recoat

* AWT - Actual UT Wall Thickness, NWT - Nominal Wall Thickness, P. - Partially

Interaction Rules: **6T**

Grind Assessment Comments:

There was a total of 55 grinds completed to repair 55 damage features as outlined in the Enbridge Gas remediation report for this site. All features were successfully removed at depths of less than 10% and the maximum grind length was 265mm. All grind repairs were found acceptable by Enbridge Gas Engineering, site to be coated and backfilled.

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line
Investigative Dig Site 2
Grind Repair Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Feature Number	Repaired Features	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	Grind Repaired?	MB31.G Burst Pressure (kPa)	Repair Details
GF-21	DF-21	TJ	768	833	65	1404	1459	55	5:01	5:13	151°	157°	11.0	11.2	0.2	2%	0.9%	Yes	10750	Recoat
GF-22	DF-22	TJ	780	815	35	712	734	22	2:32	2:37	76°	79°	10.9	11.2	0.3	3%	1.8%	Yes	10753	Recoat
GF-23	DF-23	TJ	782	850	68	471	529	58	1:41	1:53	51°	57°	10.9	11.2	0.3	3%	1.8%	Yes	10740	Recoat
GF-24	DF-24	TJ	786	818	32	1346	1382	36	4:49	4:56	145°	148°	11.0	11.2	0.2	2%	0.9%	Yes	10756	Recoat
GF-25	DF-25	TJ	1059	1091	32	2067	2139	72	7:24	7:39	222°	230°	11.0	11.2	0.2	2%	0.9%	Yes	10756	Recoat
GF-26	DF-26	TJ	1090	1147	57	2190	2220	30	7:50	7:56	235°	238°	10.8	11.2	0.4	4%	2.7%	Yes	10738	Recoat
GF-27	DF-27	TJ	1115	1160	45	450	476	26	1:36	1:42	48°	51°	10.9	11.2	0.3	3%	1.8%	Yes	10749	Recoat
GF-28	DF-28	TJ	1239	1290	51	2455	2477	22	8:47	8:52	264°	266°	10.9	11.1	0.2	2%	1.8%	Yes	10747	Recoat
GF-29	DF-29	TJ	1295	1350	55	1188	1228	40	4:15	4:23	128°	132°	10.5	11.1	0.6	5%	5.4%	Yes	10721	Recoat
GF-30	DF-30	TJ	1350	1388	38	1398	1418	20	5:00	5:04	150°	152°	10.8	11.2	0.4	4%	2.7%	Yes	10749	Recoat
GF-31	DF-31	TJ	1342	1428	86	1989	2025	36	7:07	7:15	214°	218°	10.9	11.2	0.3	3%	1.8%	Yes	10732	Recoat
GF-32	DF-32	TJ	1365	1435	70	2164	2189	25	7:44	7:50	232°	235°	11.0	11.2	0.2	2%	0.9%	Yes	10749	Recoat
GF-33	DF-33	TJ	1572	1740	168	1580	1628	48	5:39	5:49	170°	175°	10.8	11.1	0.3	3%	2.7%	Yes	10666	Recoat
GF-34	DF-34	TJ	1634	1899	265	2094	2162	68	7:29	7:44	225°	232°	10.9	11.1	0.2	2%	1.8%	Yes	10669	Recoat
GF-35	DF-35	TJ	1633	1687	54	1250	1271	21	4:28	4:33	134°	137°	10.9	11.1	0.2	2%	1.8%	Yes	10746	Recoat
GF-36	DF-36	TJ	1868	1928	60	1764	1790	26	6:18	6:24	189°	192°	11.0	11.2	0.2	2%	0.9%	Yes	10751	Recoat
GF-37	DF-37	TJ	1908	1965	57	2323	2351	28	8:19	8:25	250°	253°	11.0	11.2	0.2	2%	0.9%	Yes	10751	Recoat
GF-38	DF-38	TJ	1990	2068	78	2217	2249	32	7:56	8:03	238°	242°	11.0	11.2	0.2	2%	0.9%	Yes	10747	Recoat
GF-39	DF-39	TJ	2024	2069	45	2501	2531	30	8:57	9:03	269°	272°	11.0	11.1	0.1	1%	0.9%	Yes	10754	Recoat
GF-40	DF-40	TJ	2069	2131	62	2493	2524	31	8:55	9:02	268°	271°	11.0	11.2	0.2	2%	0.9%	Yes	10750	Recoat

* AWT - Actual UT Wall Thickness, NWT - Nominal Wall Thickness, P. - Partially

Interaction Rules: **6T**

Grind Assessment Comments:

Refer to comments on first grind page.

Pipeline Integrity Field Report

Trafalgar NPS42 3012 Bentpath Line

Investigative Dig Site 2

Grind Repair Assessment

Client: Enbridge Gas Inc.
Date: September 20, 2019
Girth Weld: GWTJ

Feature Number	Repaired Features	Ref. Girth Weld	Axial Start (mm)	Axial End (mm)	Axial Length (mm)	Circ. Start (mm)	Circ. End (mm)	Circ. Width (mm)	O'Clock From	O'Clock To	Degree Start	Degree End	Lowest UT Rem. Wall (mm)	Adjacent UT Wall Thickness (mm)	* Max Depth AWT (mm)	* Max Depth AWT (%)	* Max Depth NWT (%)	Grind Repaired?	MB31.G Burst Pressure (kPa)	Repair Details
GF-41	DF-41	TJ	2070	2095	25	490	528	38	1:45	1:53	53°	57°	10.9	11.2	0.3	3%	1.8%	Yes	10755	Recoat
GF-42	DF-42	TJ	2205	2250	45	1238	1258	20	4:25	4:30	133°	135°	11.0	11.2	0.2	2%	0.9%	Yes	10754	Recoat
GF-43	DF-43	TJ	2257	2332	75	1020	1047	27	3:39	3:44	110°	112°	10.7	11.1	0.4	4%	3.6%	Yes	10716	Recoat
GF-44	DF-44	TJ	2274	2305	31	1738	1798	60	6:13	6:26	187°	193°	10.9	11.2	0.3	3%	1.8%	Yes	10754	Recoat
GF-45	DF-45	TJ	2303	2336	33	2272	2296	24	8:08	8:13	244°	247°	11.1	11.2	0.1	1%	0.0%	Yes	10758	Recoat
GF-46	DF-46	TJ	2368	2478	110	1103	1128	25	3:56	4:02	118°	121°	11.0	11.2	0.2	2%	0.9%	Yes	10740	Recoat
GF-47	DF-47	TJ	2550	2594	44	1968	2000	32	7:02	7:09	211°	215°	11.0	11.1	0.1	1%	0.9%	Yes	10754	Recoat
GF-48	DF-48	TJ	2567	2608	41	2487	2515	28	8:54	9:00	267°	270°	11.0	11.2	0.2	2%	0.9%	Yes	10754	Recoat
GF-49	DF-49	TJ	2620	2656	36	2241	2261	20	8:01	8:05	241°	243°	11.0	11.2	0.2	2%	0.9%	Yes	10755	Recoat
GF-50	DF-50	TJ	2632	2690	58	1370	1400	30	4:54	5:00	147°	150°	11.0	11.2	0.2	2%	0.9%	Yes	10751	Recoat
GF-51	DF-51	TJ	2683	2809	126	1959	1999	40	7:00	7:09	210°	215°	11.1	11.2	0.1	1%	0.0%	Yes	10758	Recoat
GF-52	DF-52	TJ	2783	2869	86	2243	2277	34	8:01	8:09	241°	245°	11.1	11.2	0.1	1%	0.0%	Yes	10758	Recoat
GF-53	DF-53	TJ	2800	2842	42	923	951	28	3:18	3:24	99°	102°	11.0	11.2	0.2	2%	0.9%	Yes	10754	Recoat
GF-54	DF-54	TJ	2910	2960	50	1510	1532	22	5:24	5:29	162°	165°	11.0	11.1	0.1	1%	0.9%	Yes	10753	Recoat
GF-55	DF-55	TJ	2855	2959	104	1102	1142	40	3:56	4:05	118°	123°	10.9	11.2	0.3	3%	1.8%	Yes	10724	Recoat

* AWT - Actual UT Wall Thickness, NWT - Nominal Wall Thickness, P. - Partially

Interaction Rules: **6T**

Grind Assessment Comments:

Refer to comments on first grind page.

ENBRIDGE GAS INC. - TRAFALGAR NPS42

001 - SITE OVERVIEW LOOKING DOWNSTREAM

002 - SITE OVERVIEW LOOKING UPSTREAM

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

003 - SPOIL PILE

004 - BROWN SOIL DOMINATES ON SIDE WALLS OF EXCAVATION

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

005 - ASSESSMENT OVERVIEW, NOTE REFERENCE POINT

006 - COATING ASSESSMENT AREA 3 O'CLOCK SIDE

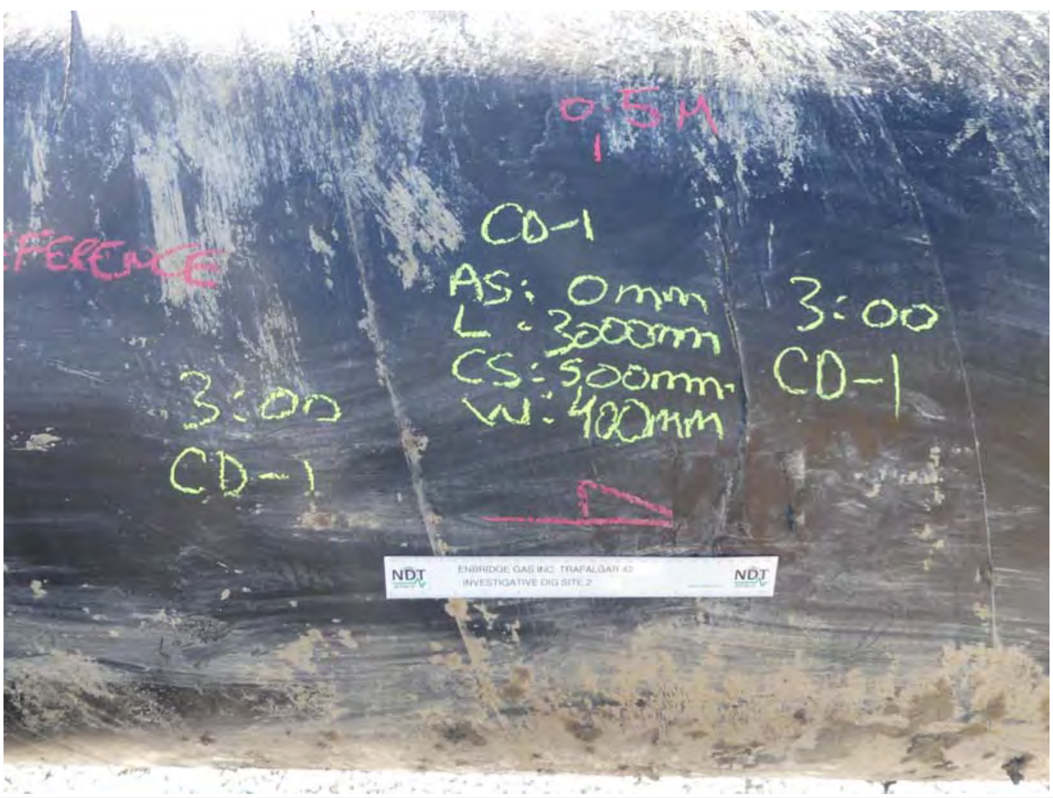
ENBRIDGE GAS INC. - TRAFALGAR NPS42

007 - COATING ASSESSMENT AREA 9 O'CLOCK SIDE

008 - CD-01 OVERVIEW 3 O'CLOCK SIDE

ENBRIDGE GAS INC. - TRAFALGAR NPS42

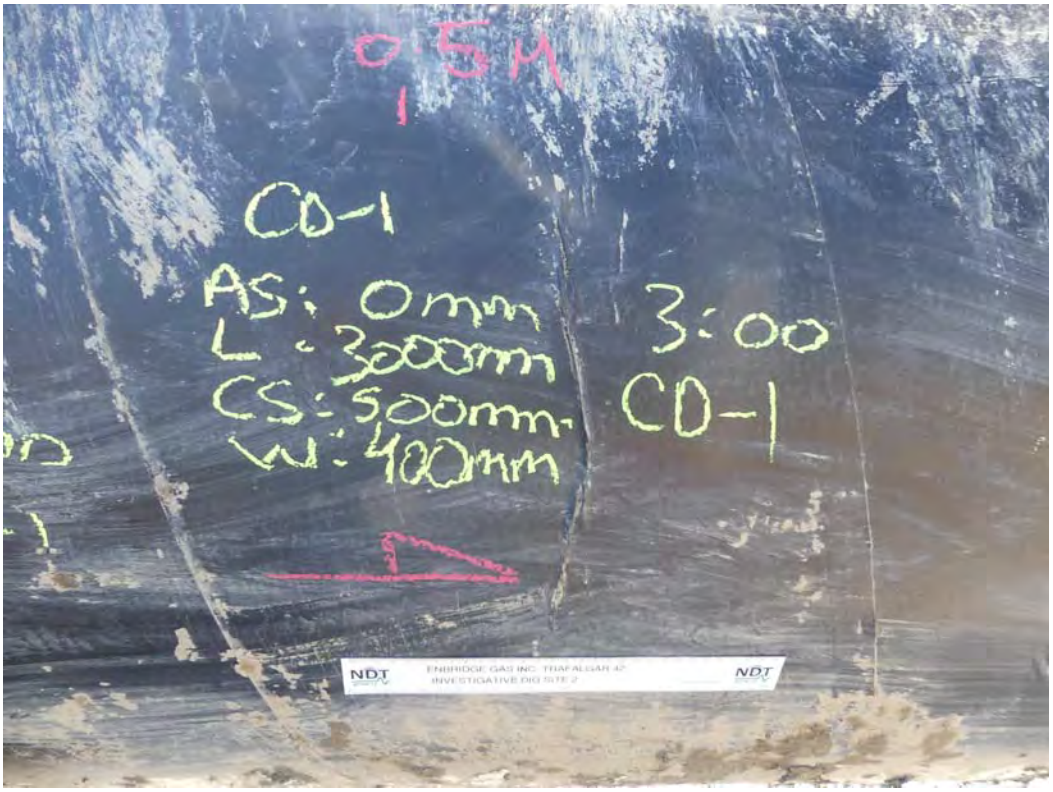
009 - CD-01



010 - CD-01 (2)

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42



011 - CD-01 CLOSE-UP (1)

012 - CD-01 CLOSE-UP (2)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

013 - CD-01 COATING REMOVED BLACK, ORANGE CORROSION DEPOSIT

014 - CD-01 COATING REMOVED, BLACK, WHITE CORROSION DEPOSIT

ENBRIDGE GAS INC. - TRAFALGAR NPS42

015 - CD-02 OVERVIEW TENTING ALONG LONG SEAM

016 - CD-02 TENTING ALONG THE LONG SEAM

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

017 - CD-02 CLOSE-UP (1)

018 - CD-02 CLOSE-UP (2)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

019 - CD-02 CLOSE-UP (3)

020 - CD-02 COATING REMOVED BLACK CORROSION DEPOSIT

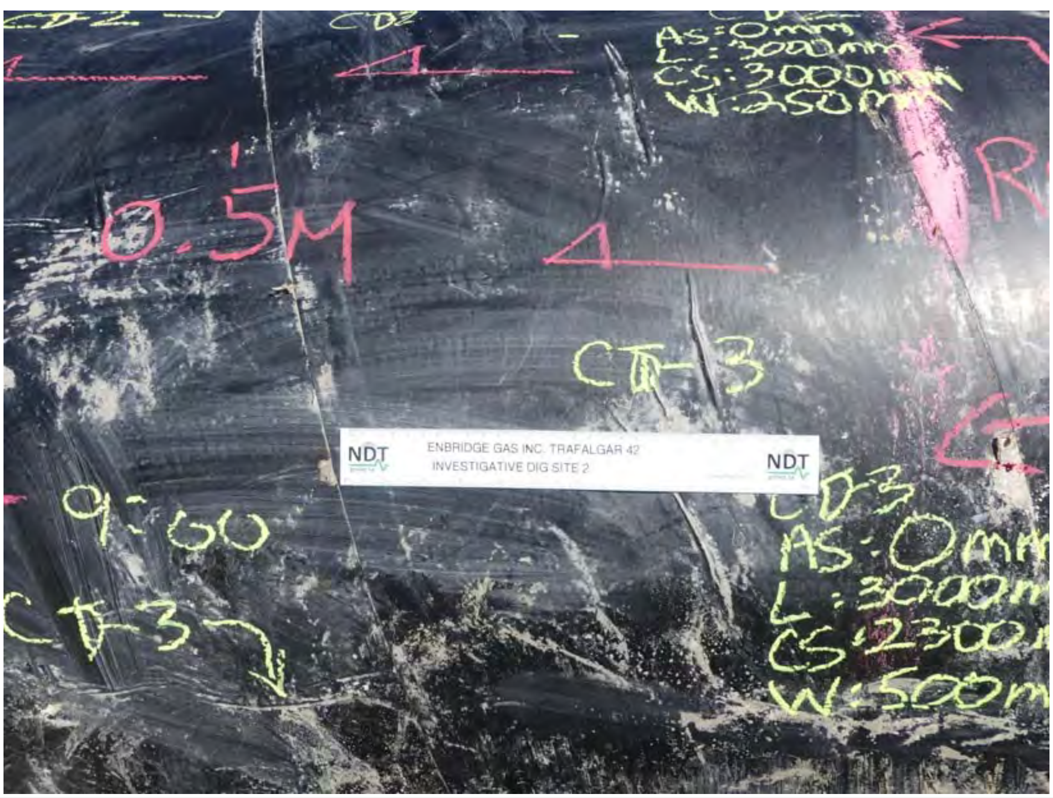
ENBRIDGE GAS INC. - TRAFALGAR NPS42

021 - CD-02 COATING REMOVED BLACK, ORANGE CORROSION DEPOSIT

022 - CD-02 COATING REMOVED PASTY GREY CORROSION DEPOSIT CLOSE-UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

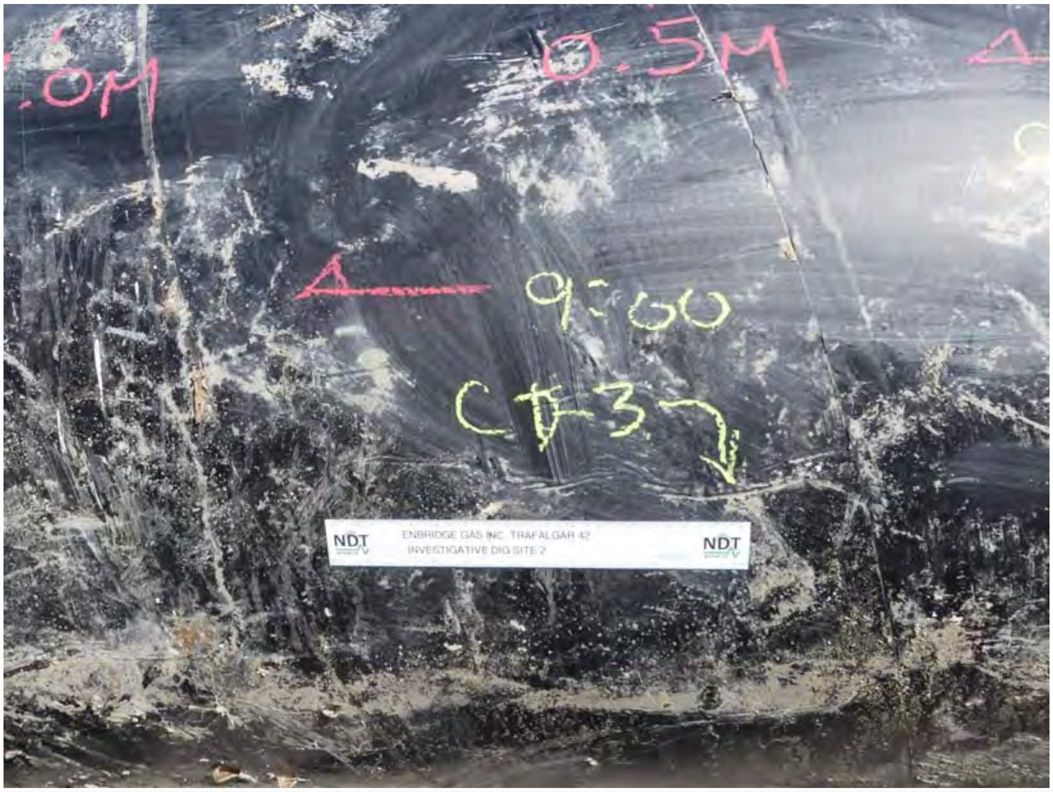
023 - CD-03



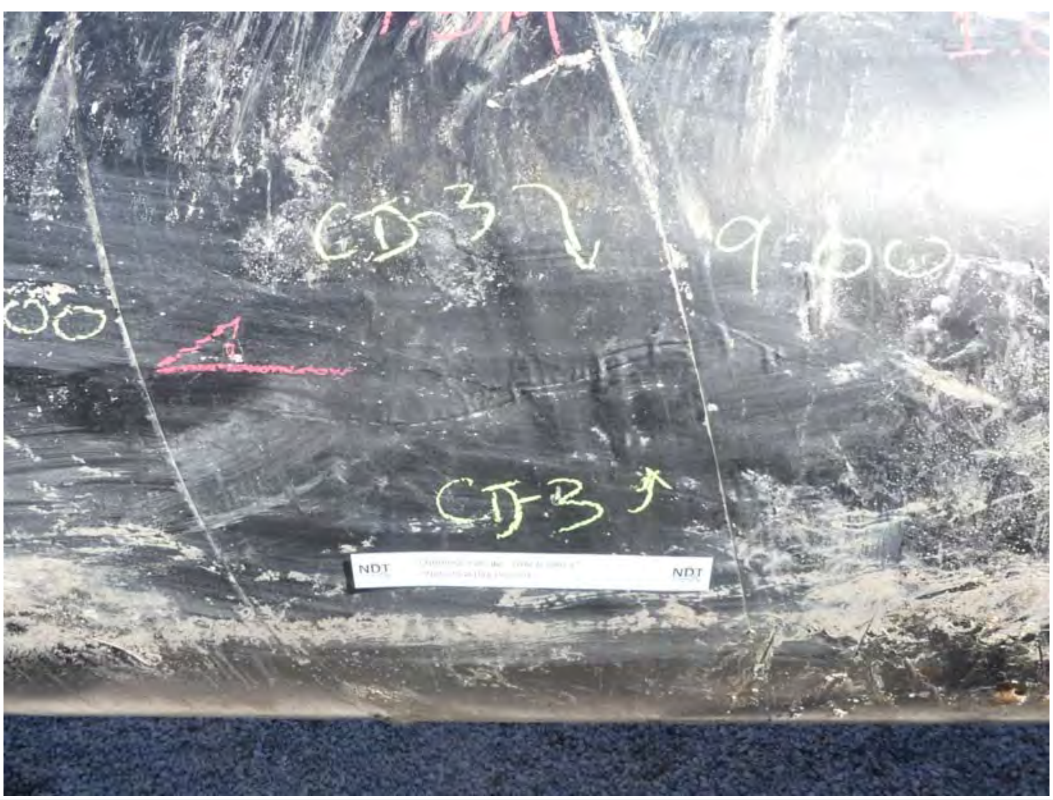
024 - CD-03 CLOSE-UP (1)

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

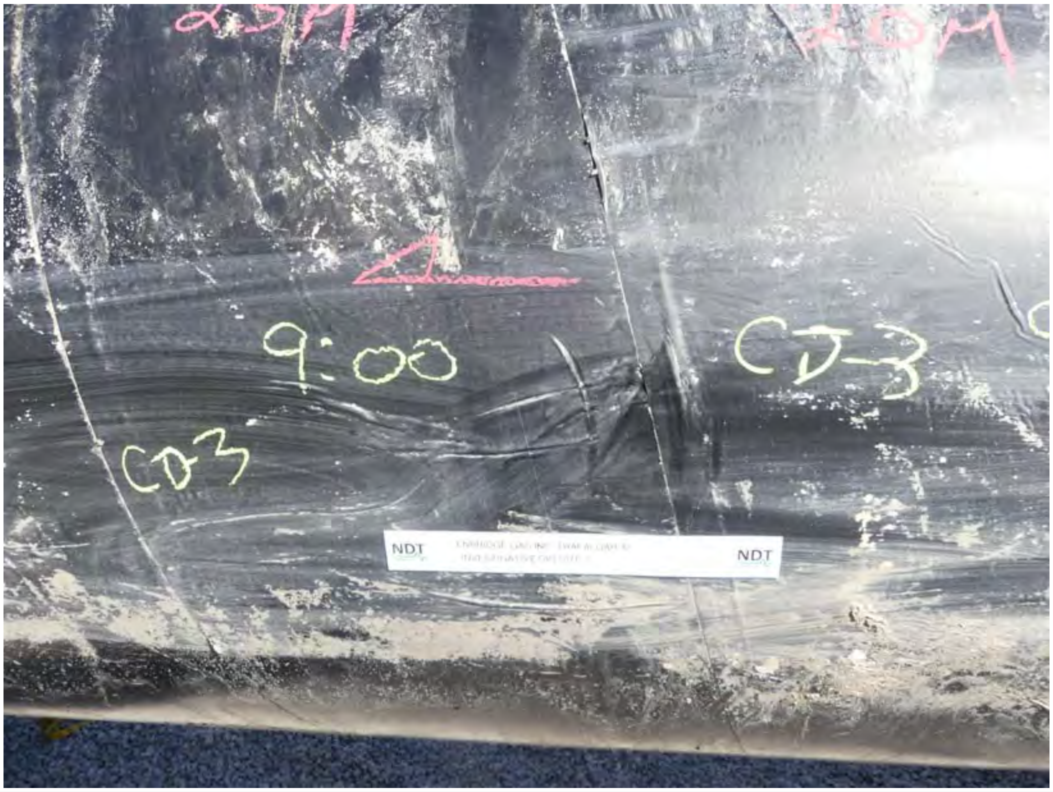


025 - CD-03 CLOSE-UP (2)

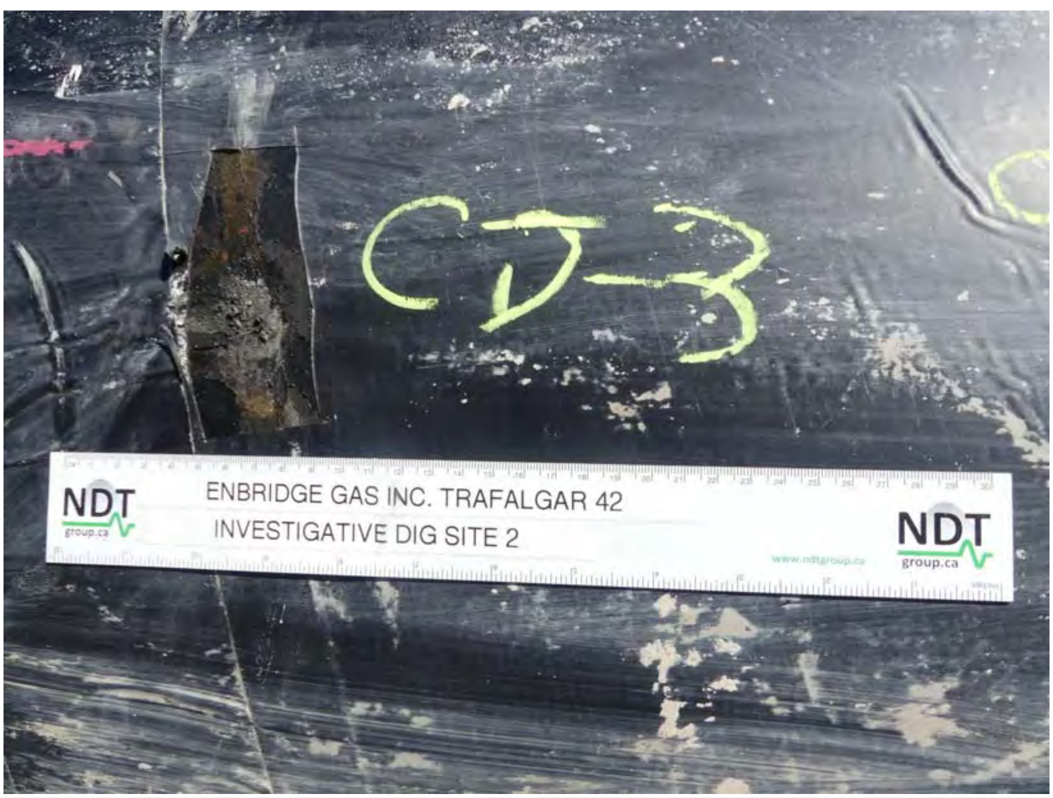


026 - CD-03 CLOSE-UP (3)

ENBRIDGE GAS INC. - TRAFALGAR NPS42



027 - CD-03 CLOSE-UP(4)



028 - CD-03 COATING REMOVED BLACK, WHITE CORROSION DEPOSIT

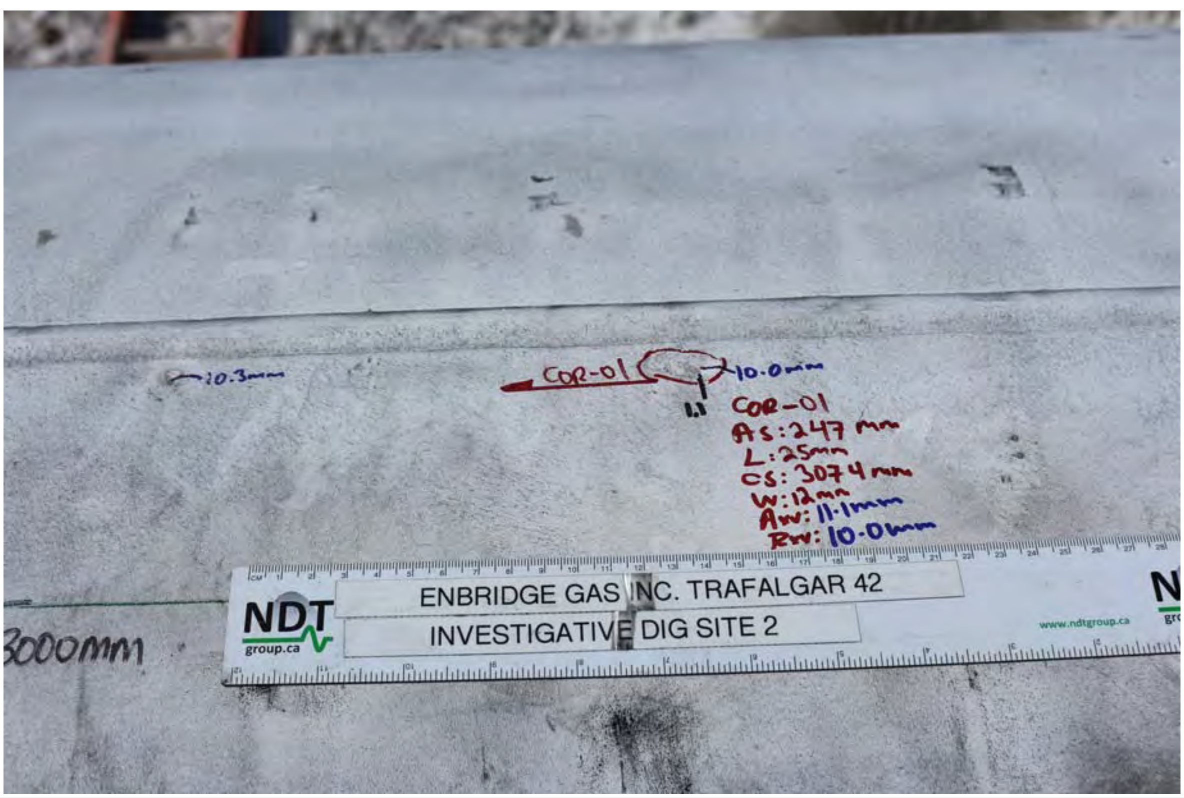
ENBRIDGE GAS INC. - TRAFALGAR NPS42

029 - CD-03 COATING REMOVED WHITE, BLACK CORROSION DEPOSIT (1)

030 - CD-03 COATING REMOVED WHITE, BLACK CORROSION DEPOSIT (2)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

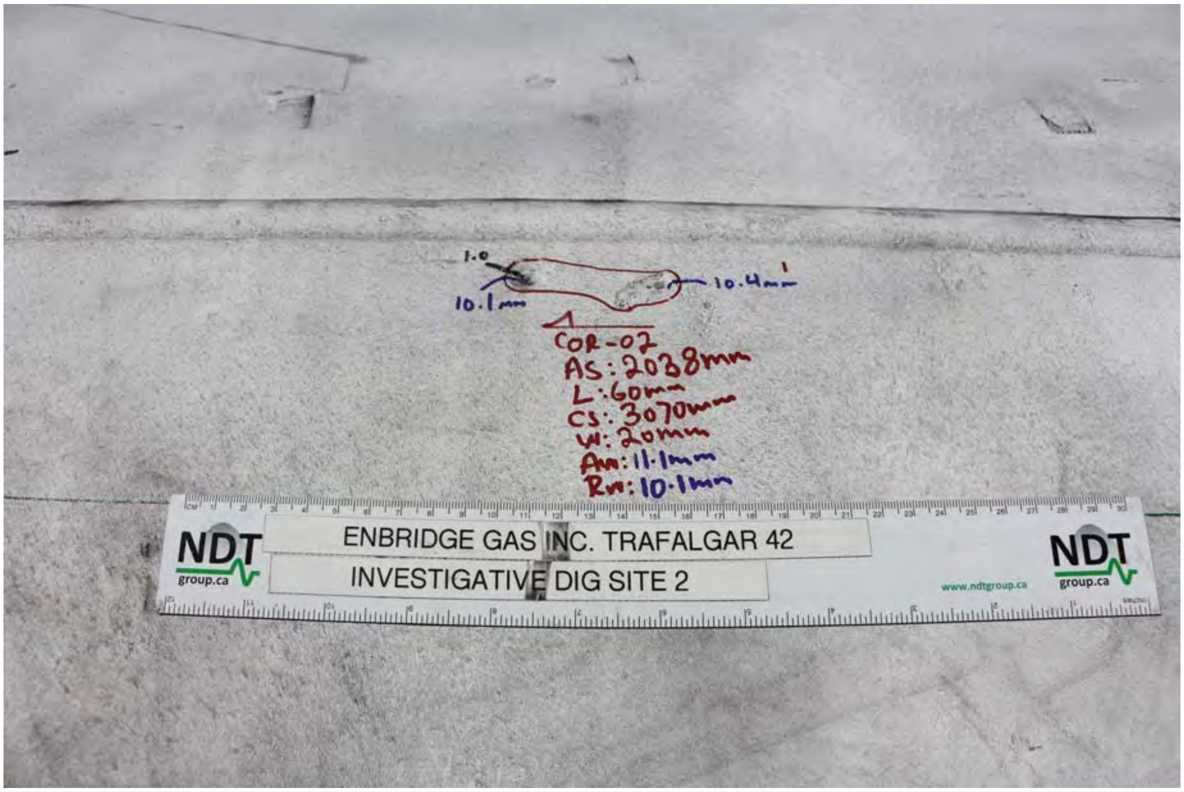
031 - CD-03 COATING REMOVED, CORROSION DEPOSIT AT 1.5 M



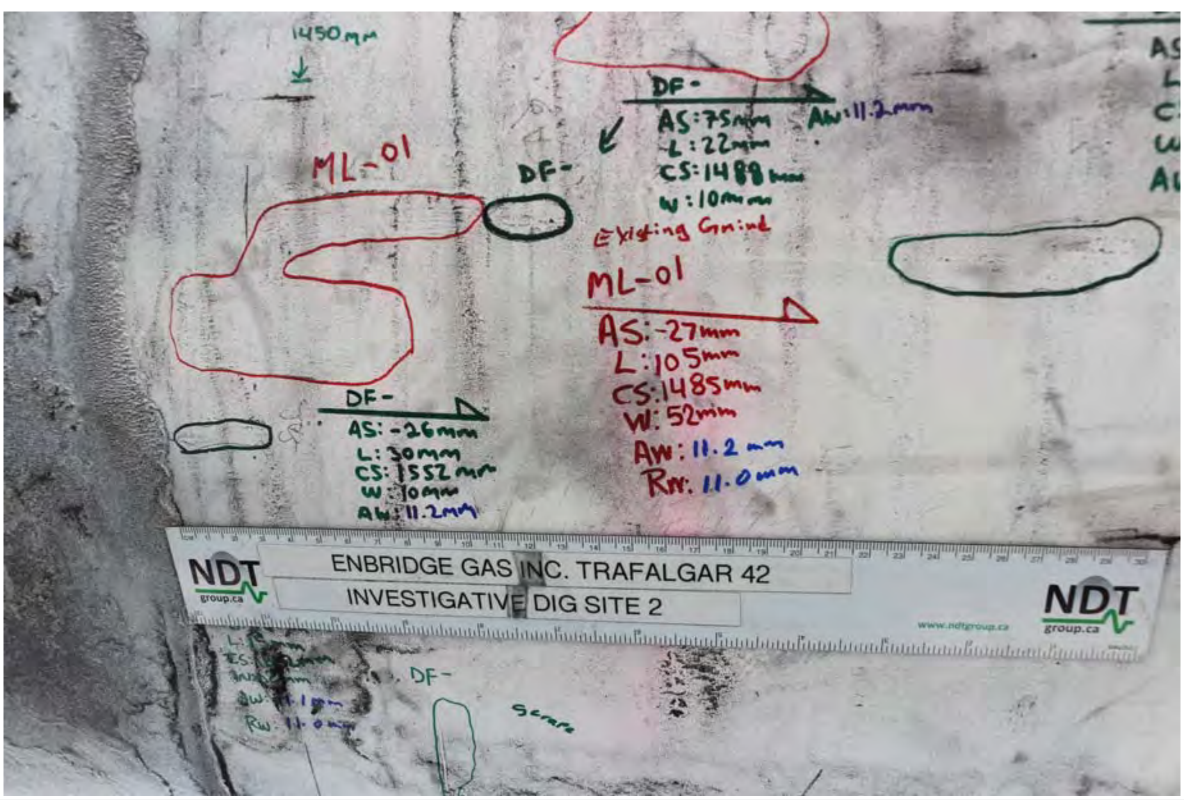
032 - COR-01

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

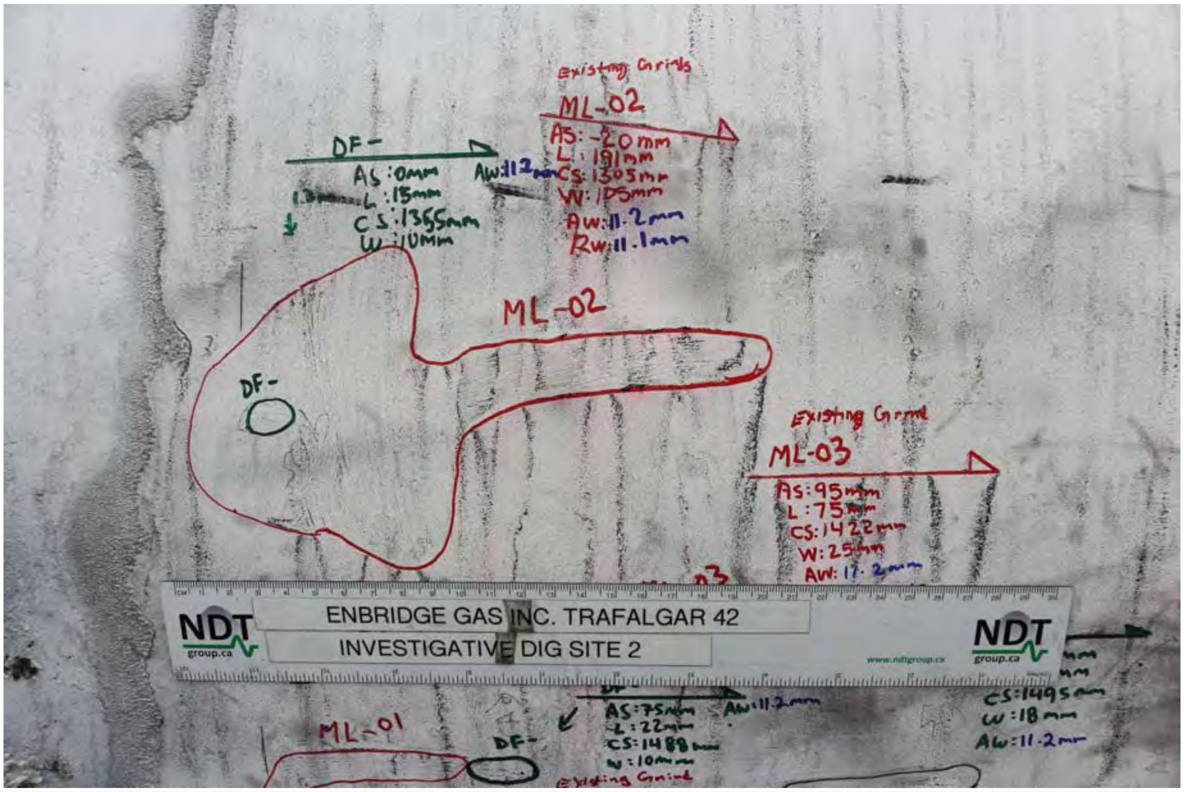


033 - COR-02

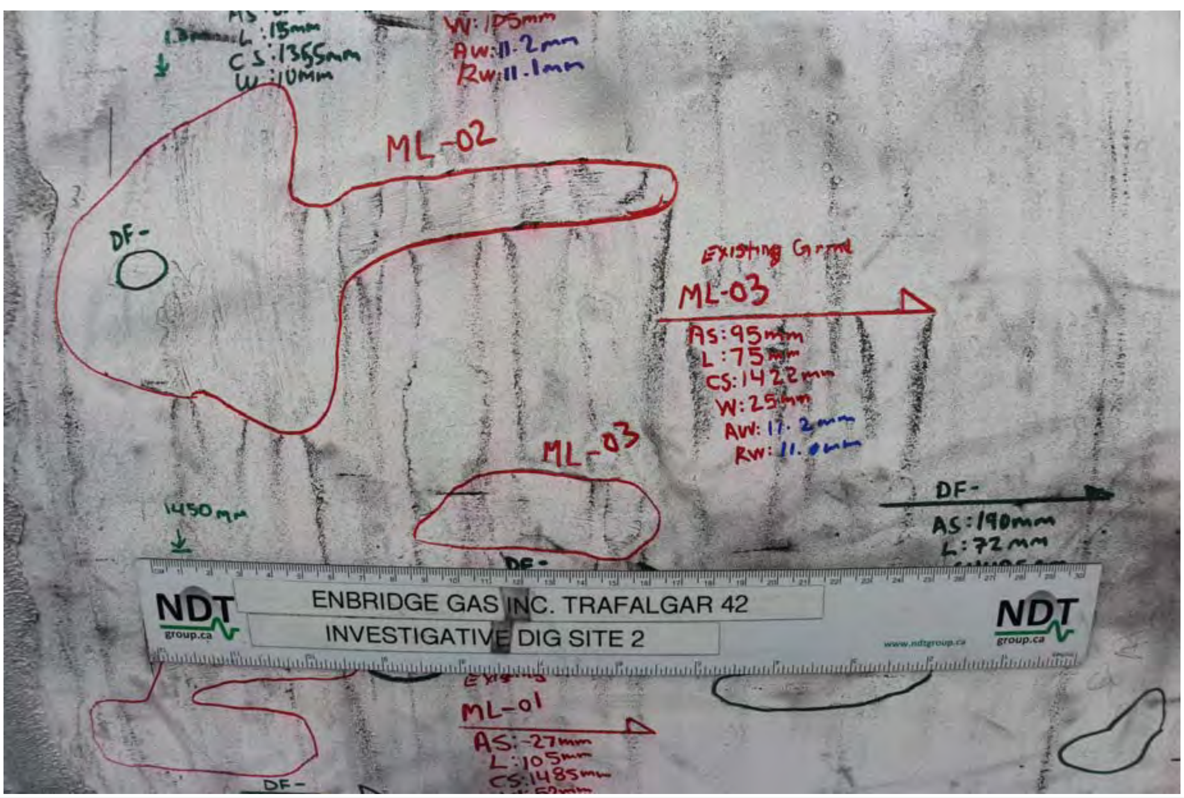


034 - ML-01

ENBRIDGE GAS INC. - TRAFALGAR NPS42

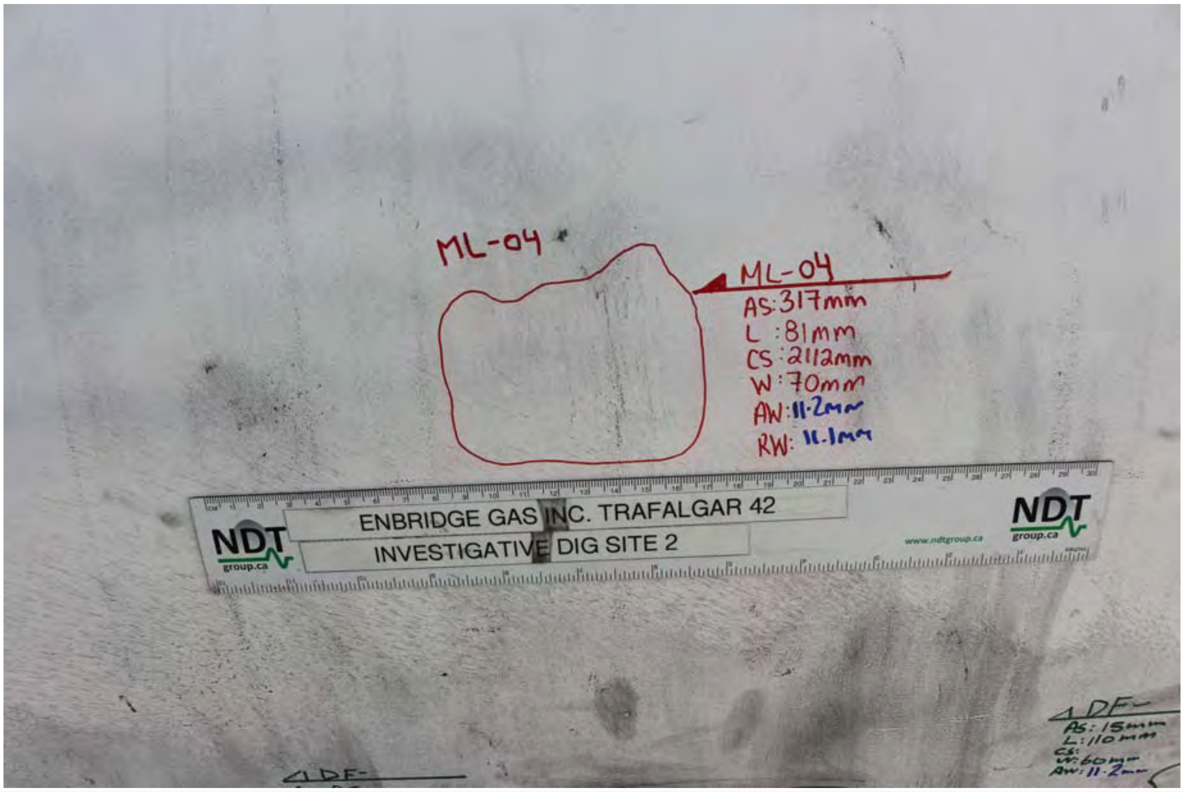


035 - ML-02

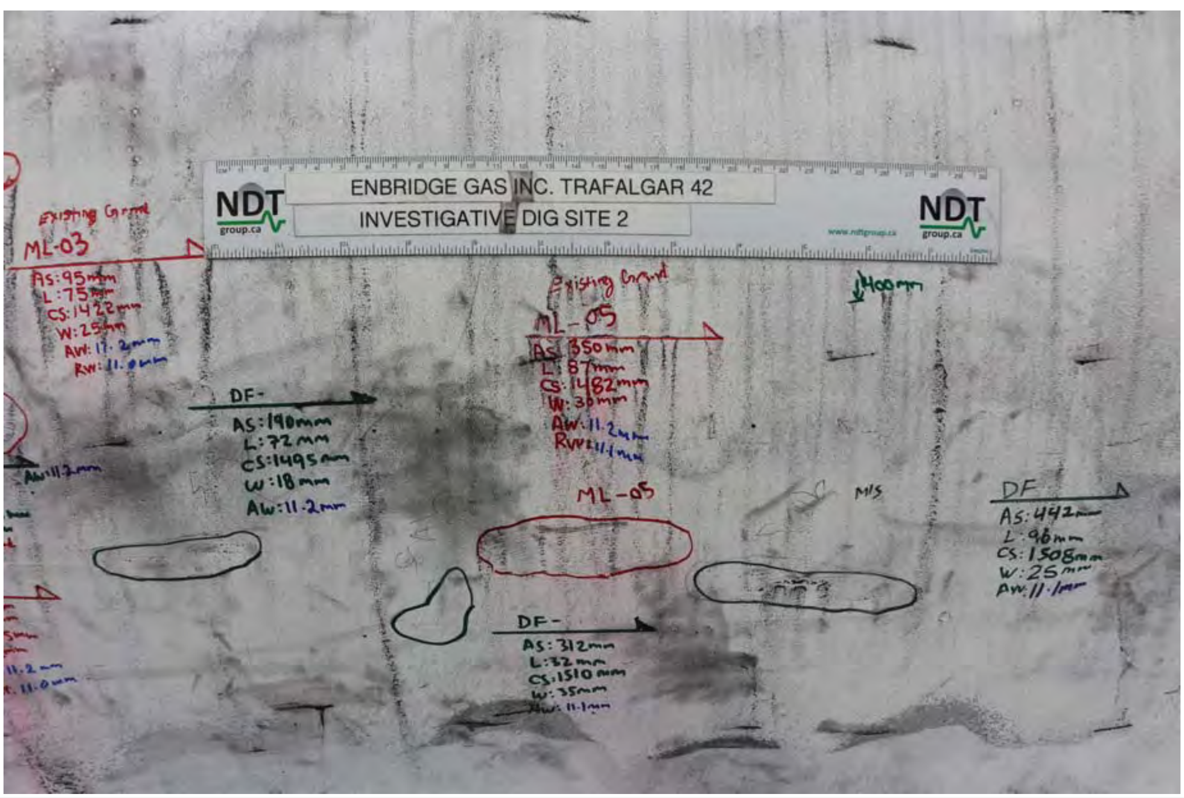


036 - ML-03

ENBRIDGE GAS INC. - TRAFALGAR NPS42

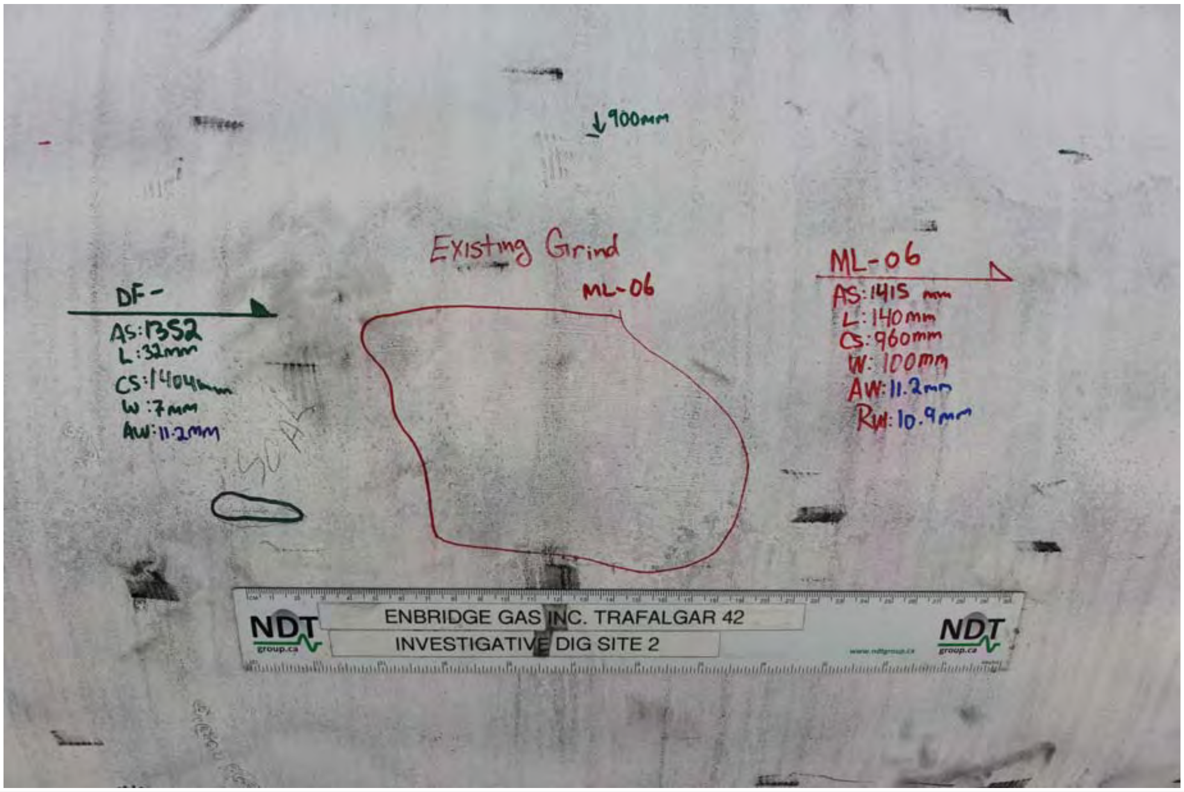


037 - ML-04

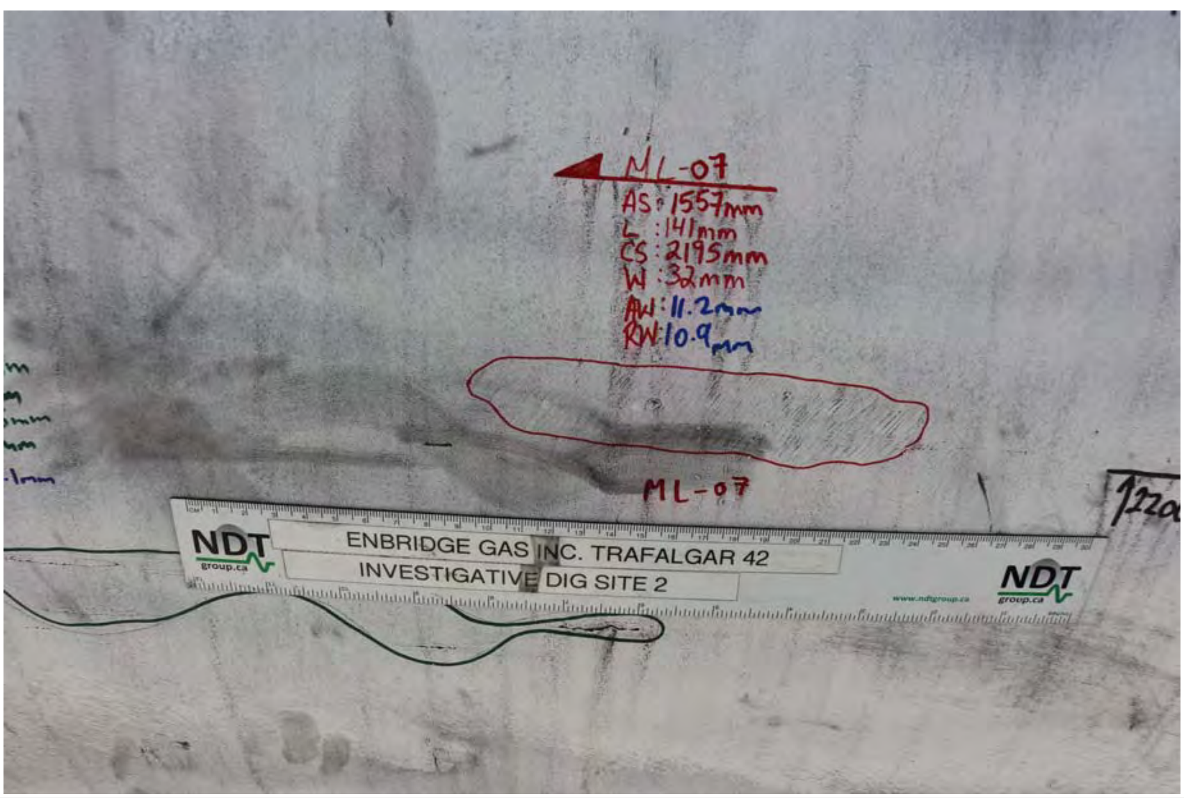


038 - ML-05

ENBRIDGE GAS INC. - TRAFALGAR NPS42

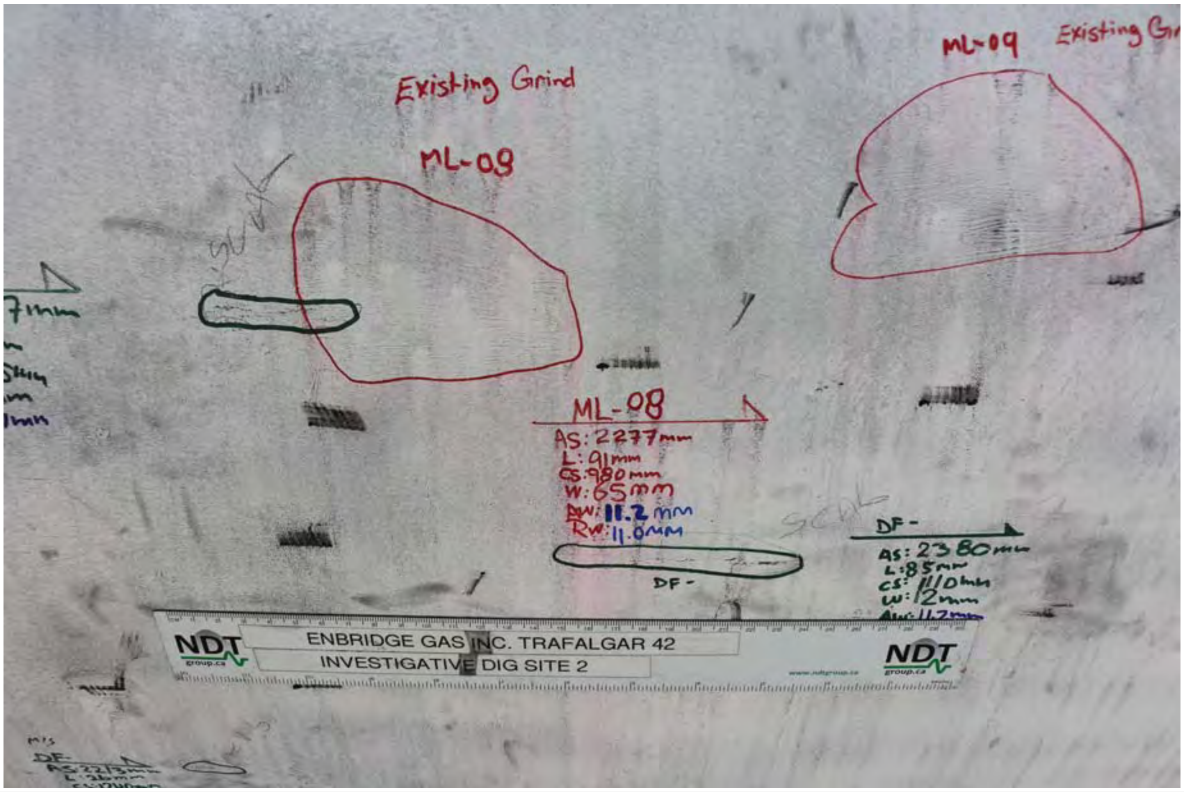


039 - ML-06

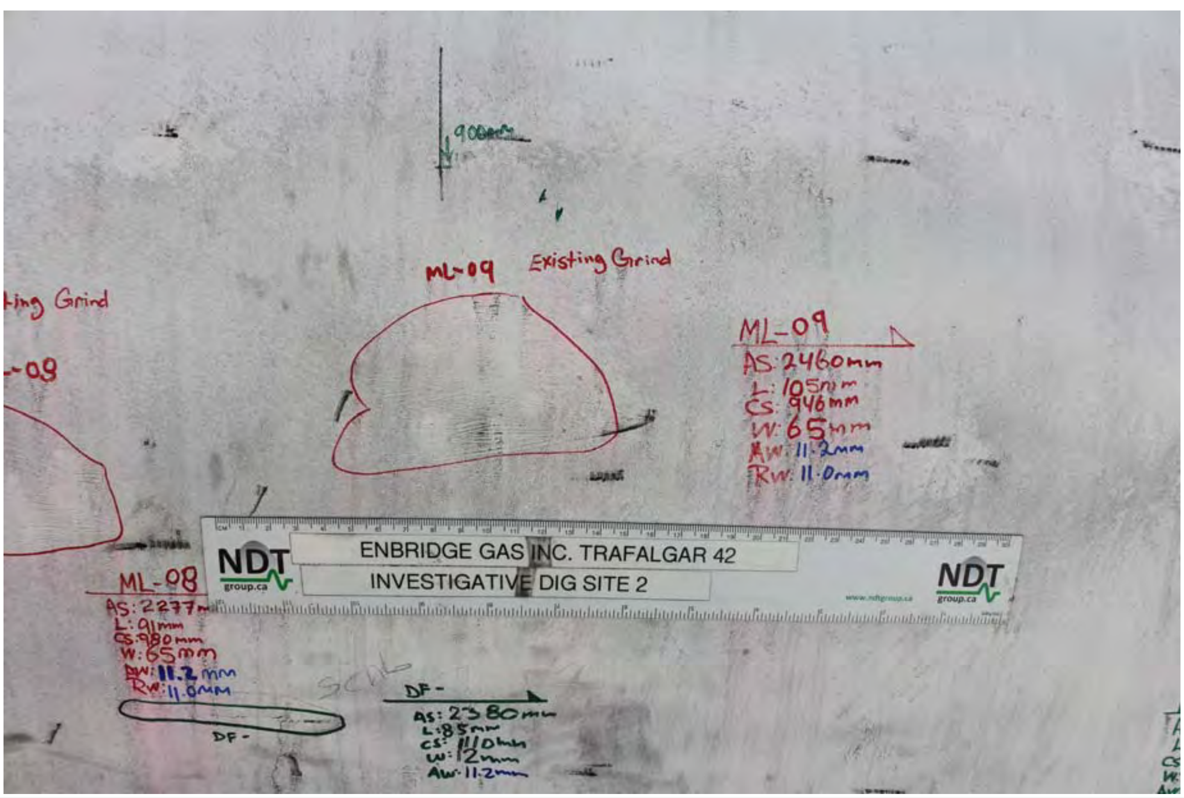


040 - ML-07

ENBRIDGE GAS INC. - TRAFALGAR NPS42

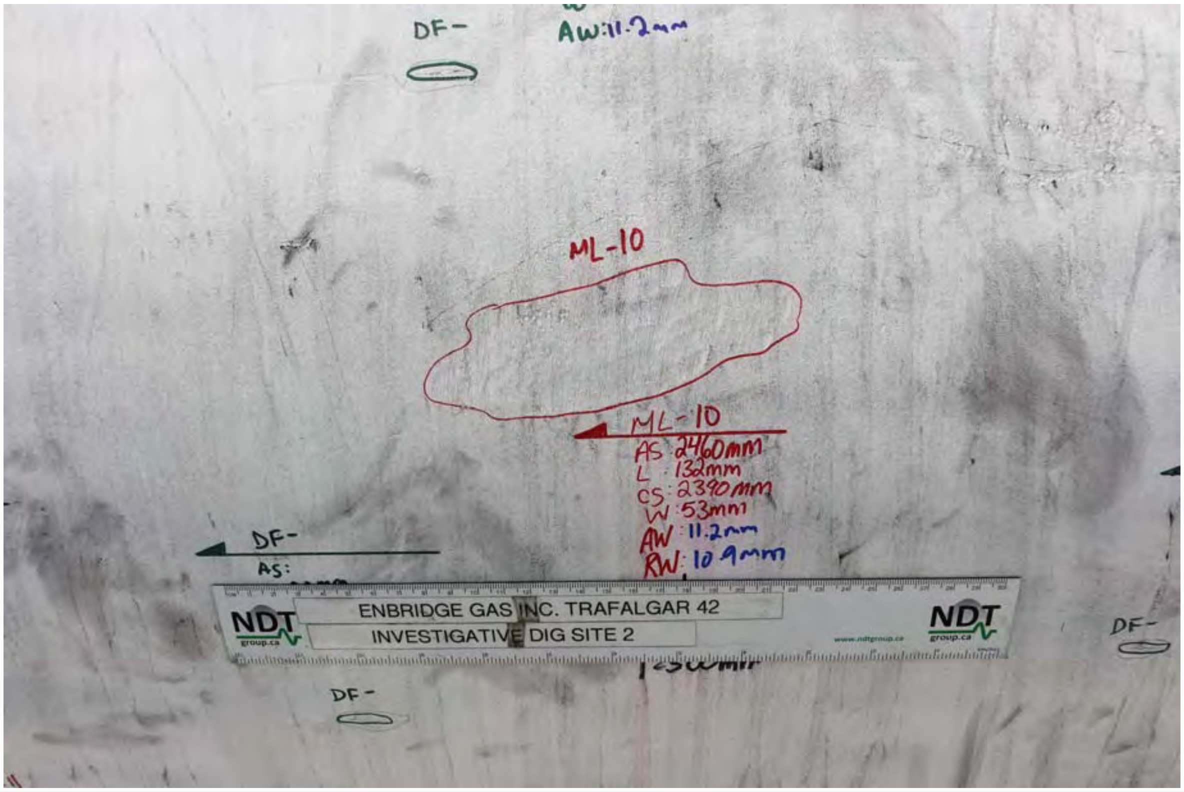


041 - ML-08

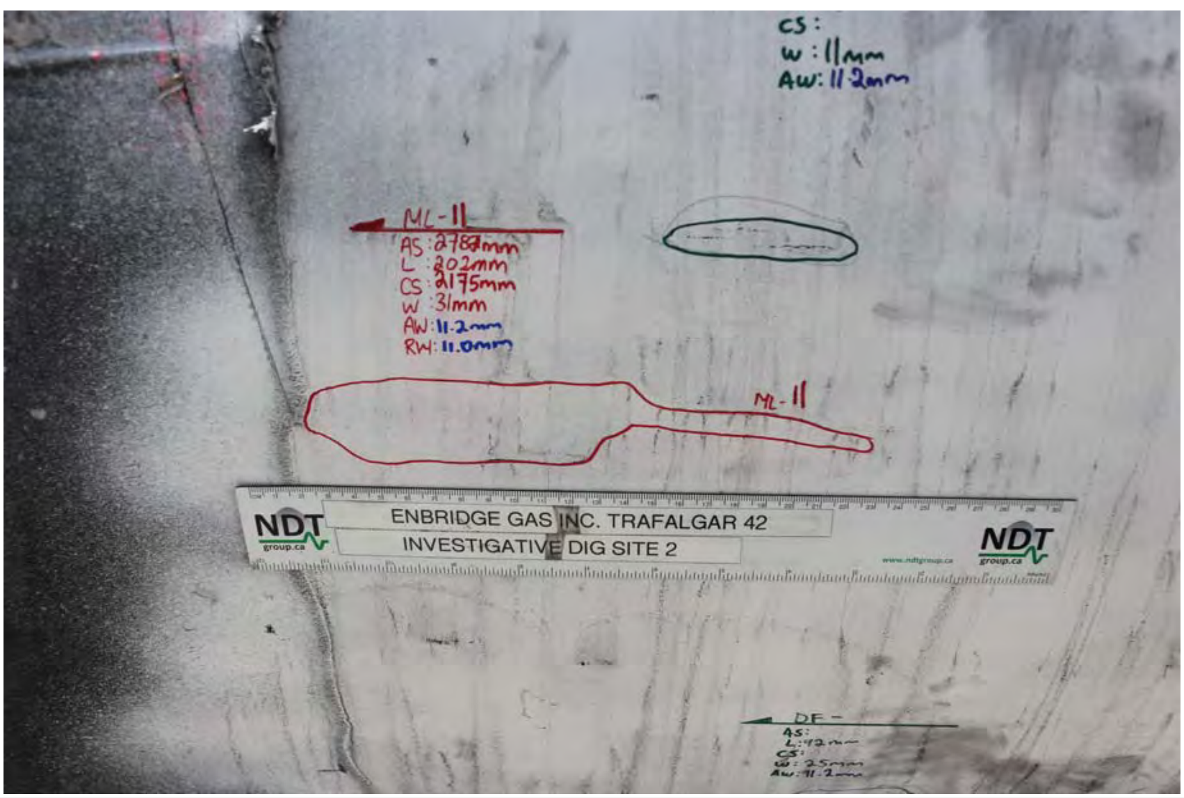


042 - ML-09

ENBRIDGE GAS INC. - TRAFALGAR NPS42

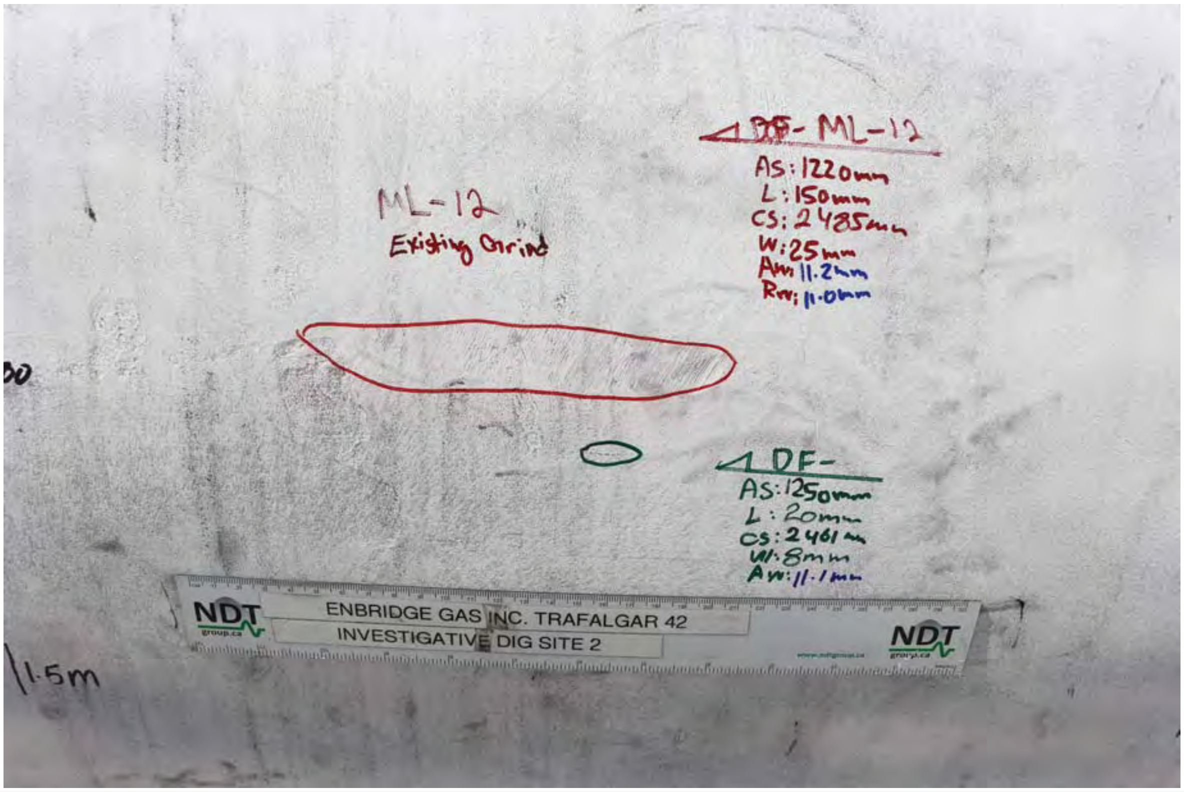


043 - ML-10

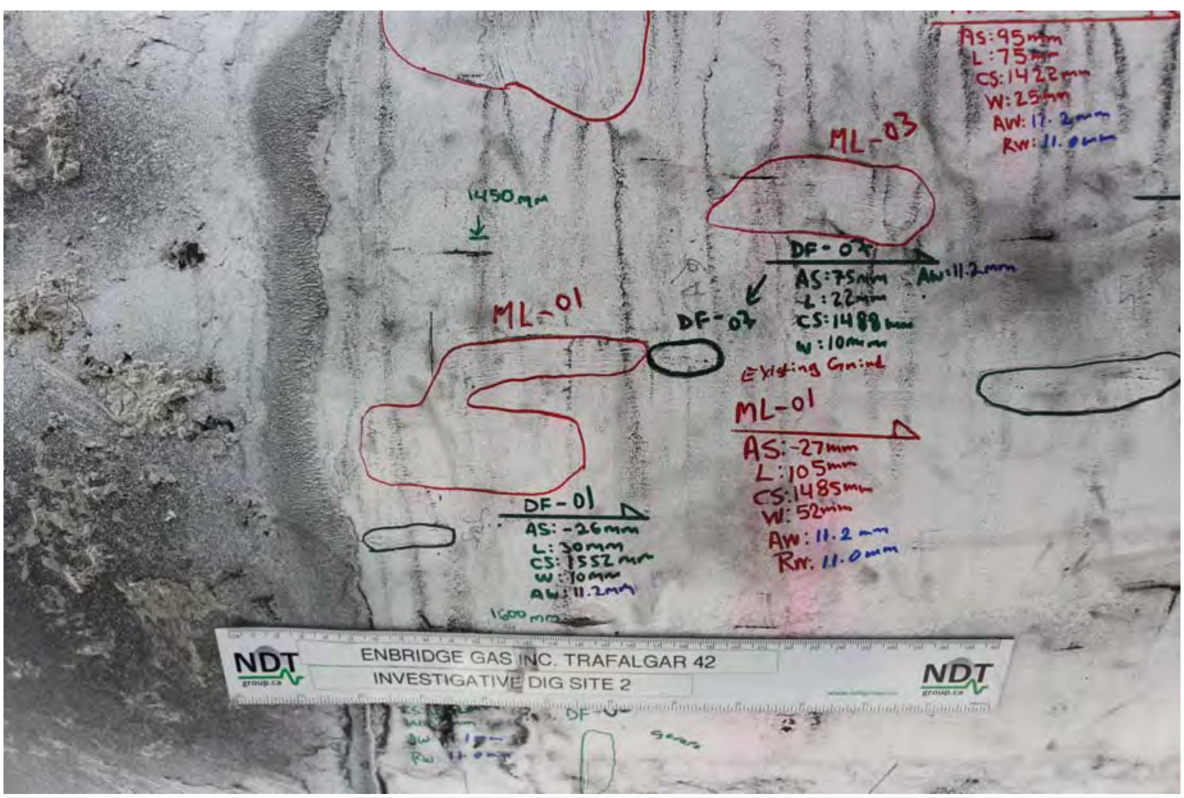


044 - ML-11

ENBRIDGE GAS INC. - TRAFALGAR NPS42

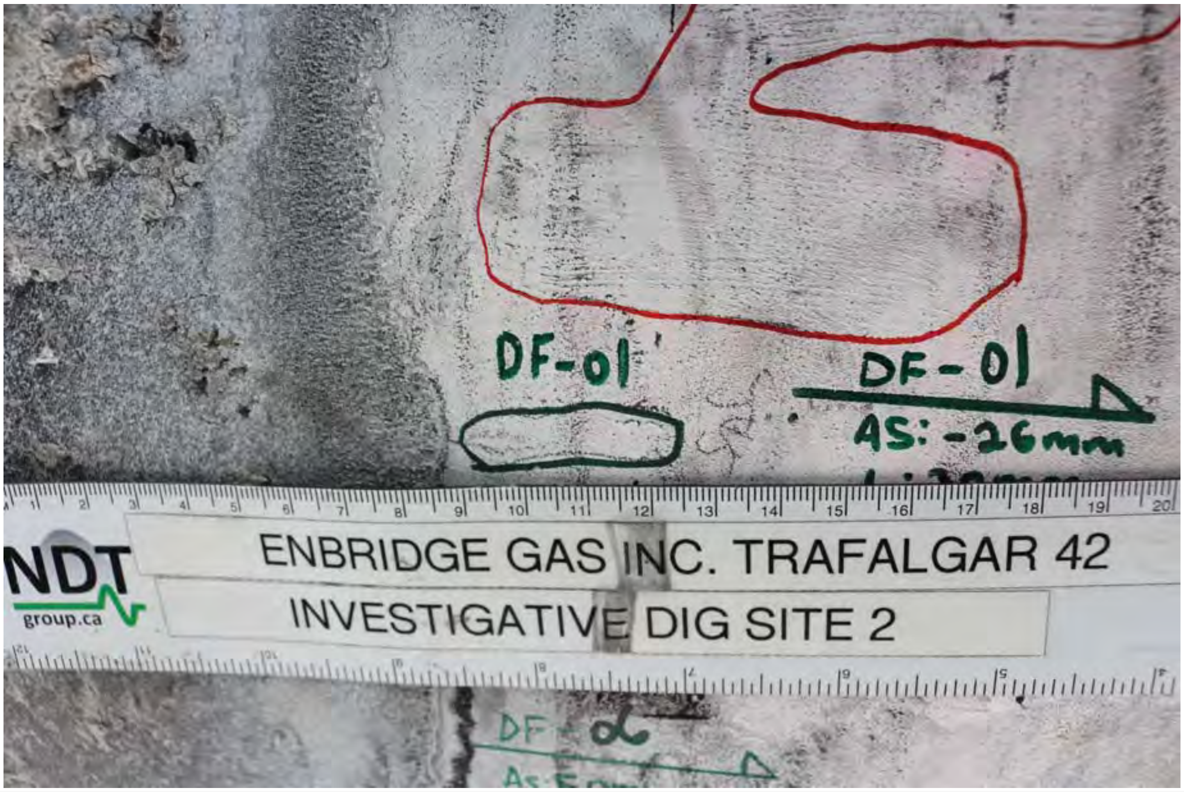


045 - ML-12

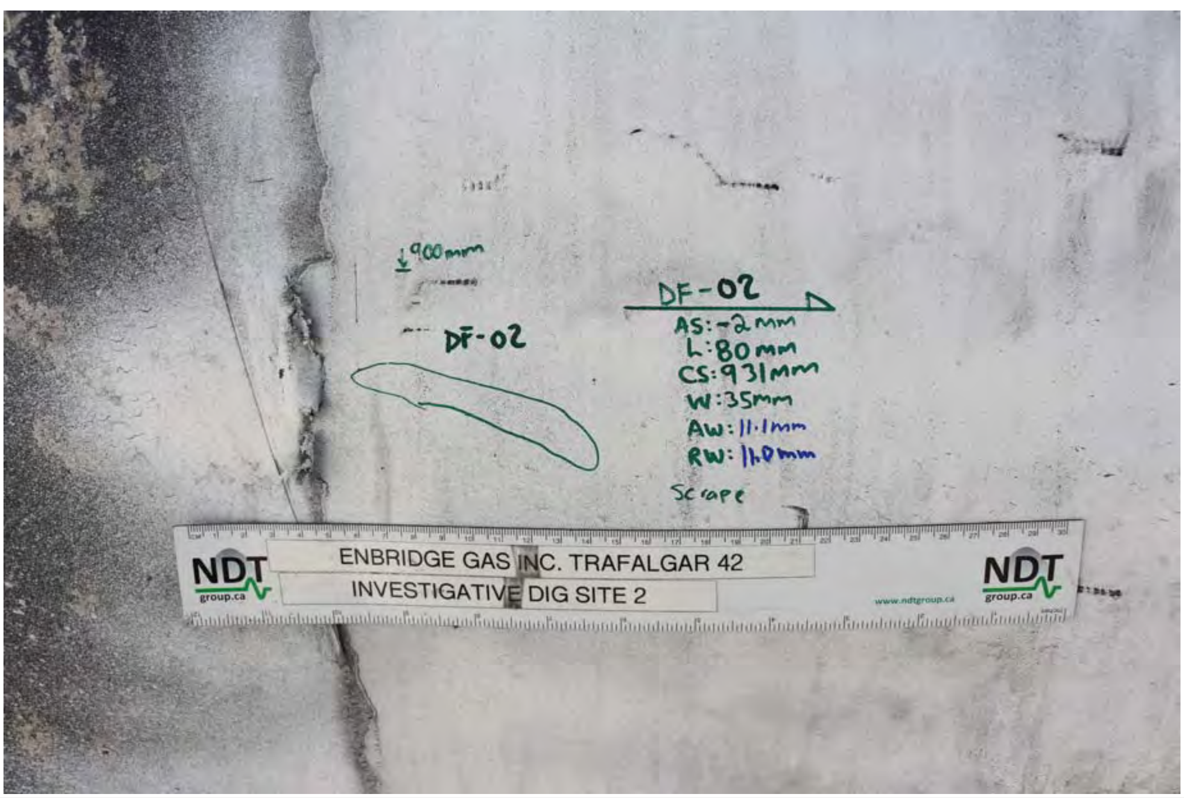


046 - DF-01

ENBRIDGE GAS INC. - TRAFALGAR NPS42

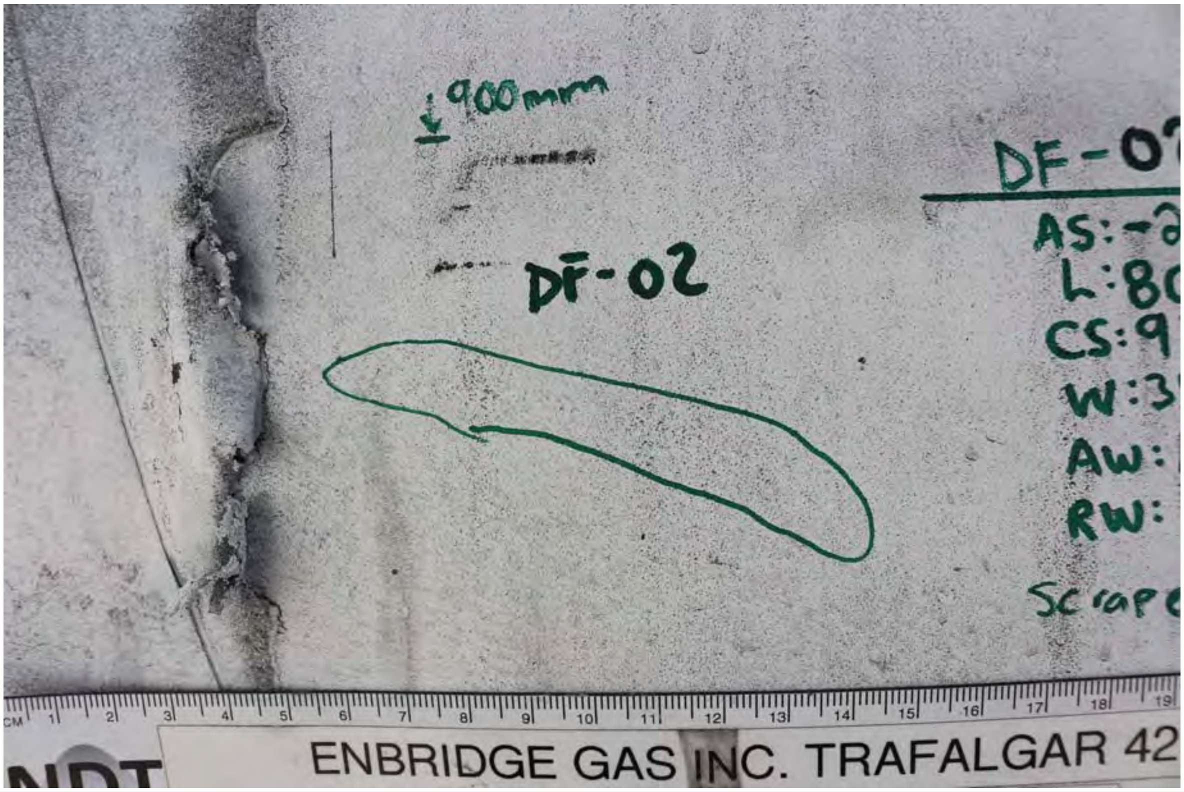


047 - DF-01 CLOSE UP

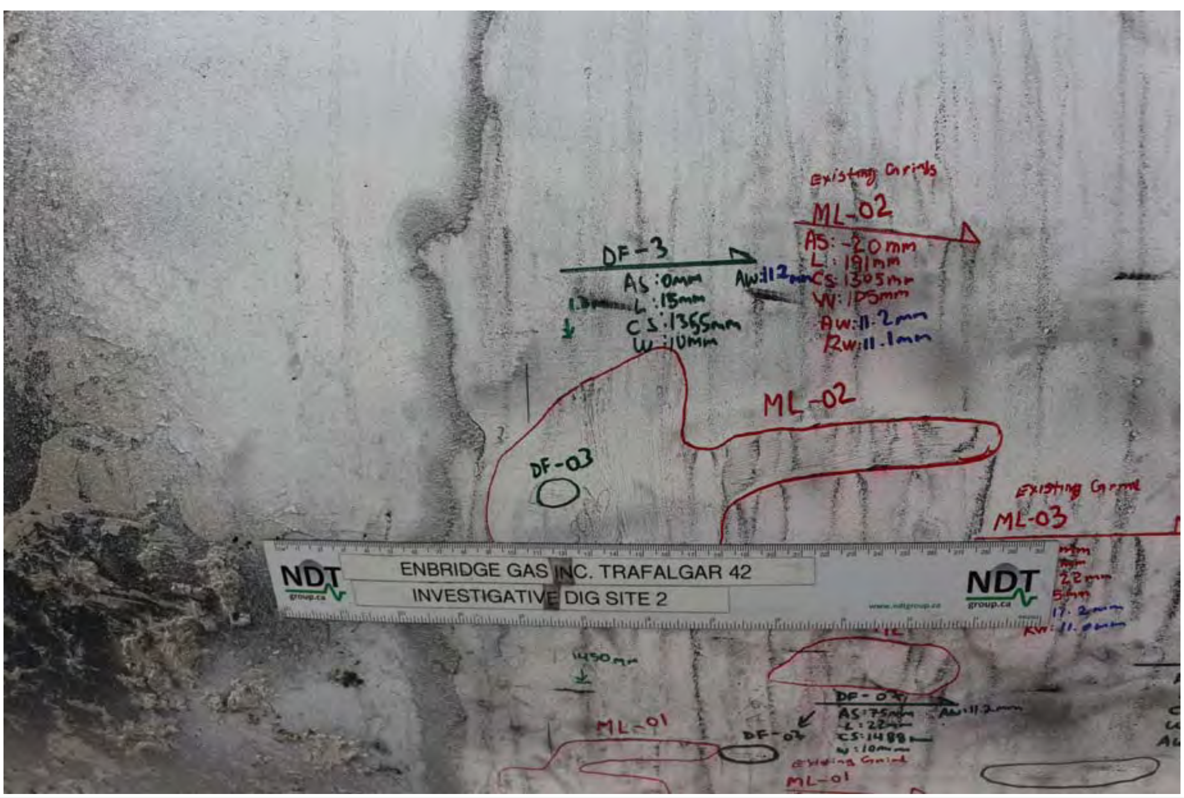


048 - DF-02

ENBRIDGE GAS INC. - TRAFALGAR NPS42

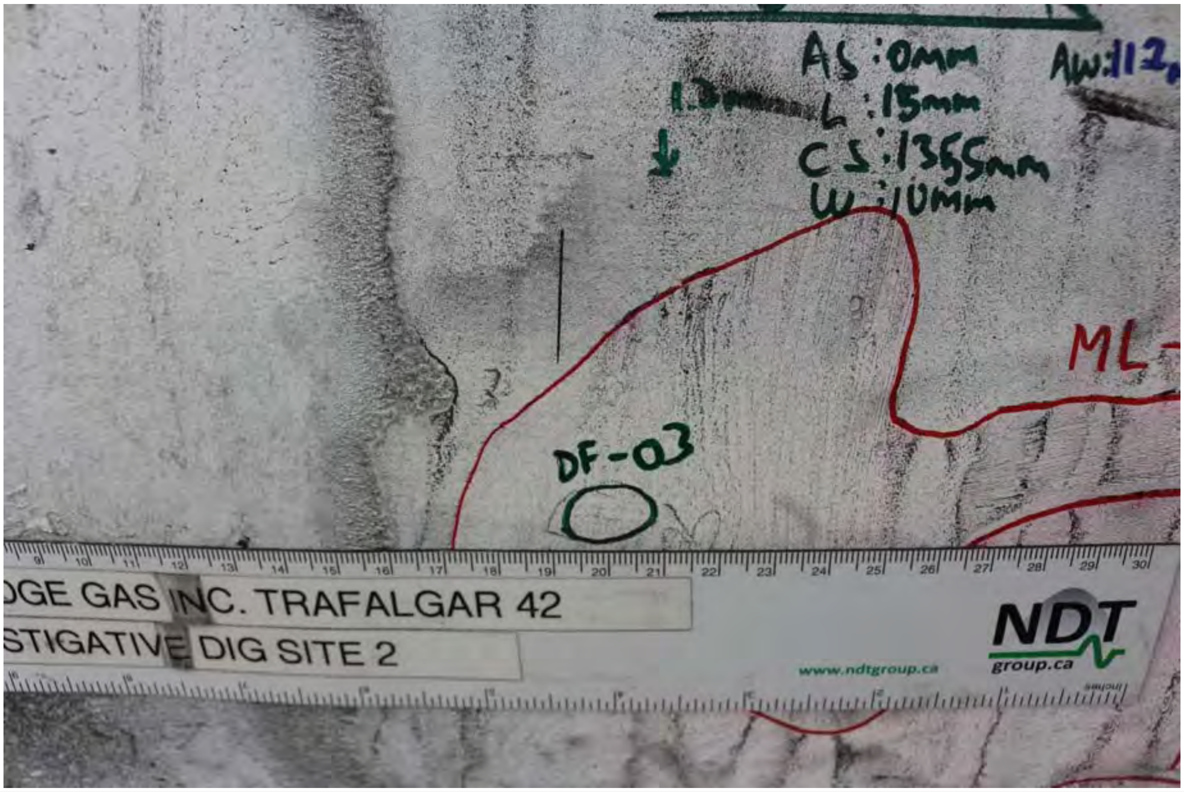


049 - DF-02 CLOSE UP

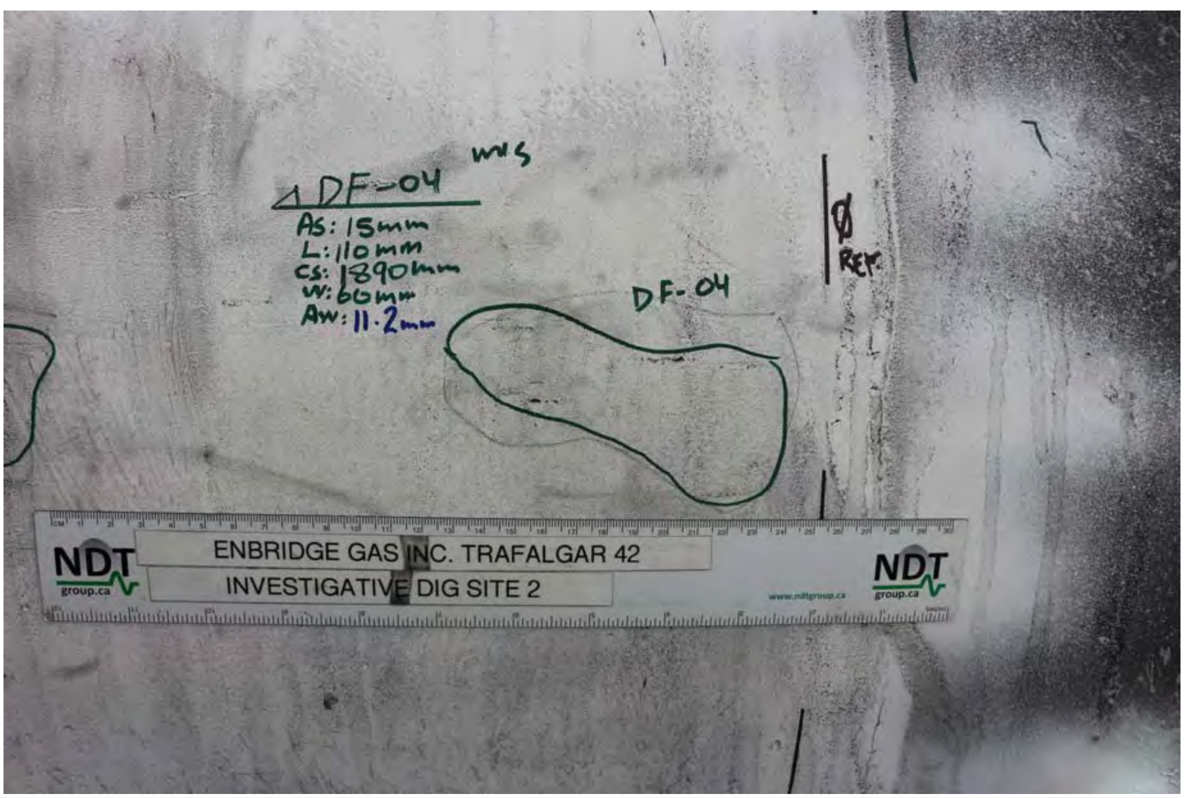


050 - DF-03

ENBRIDGE GAS INC. - TRAFALGAR NPS42

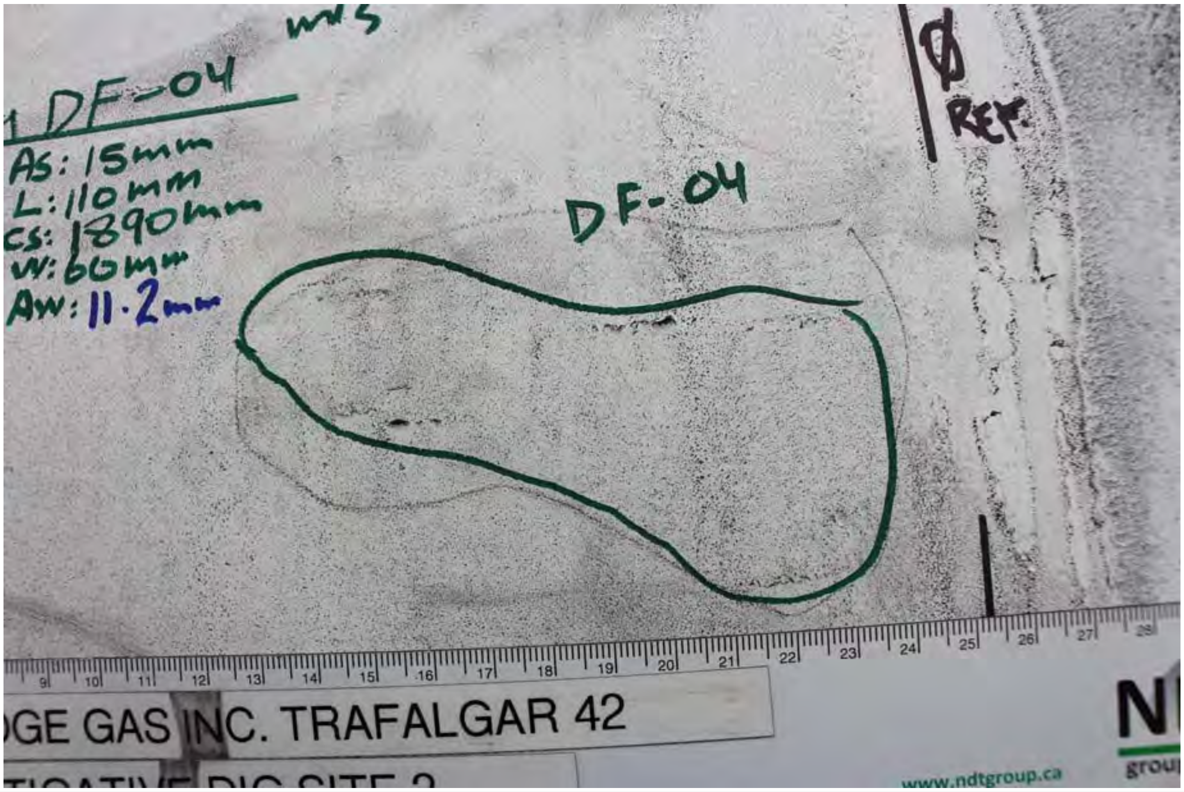


051 - DF-03 CLOSE UP

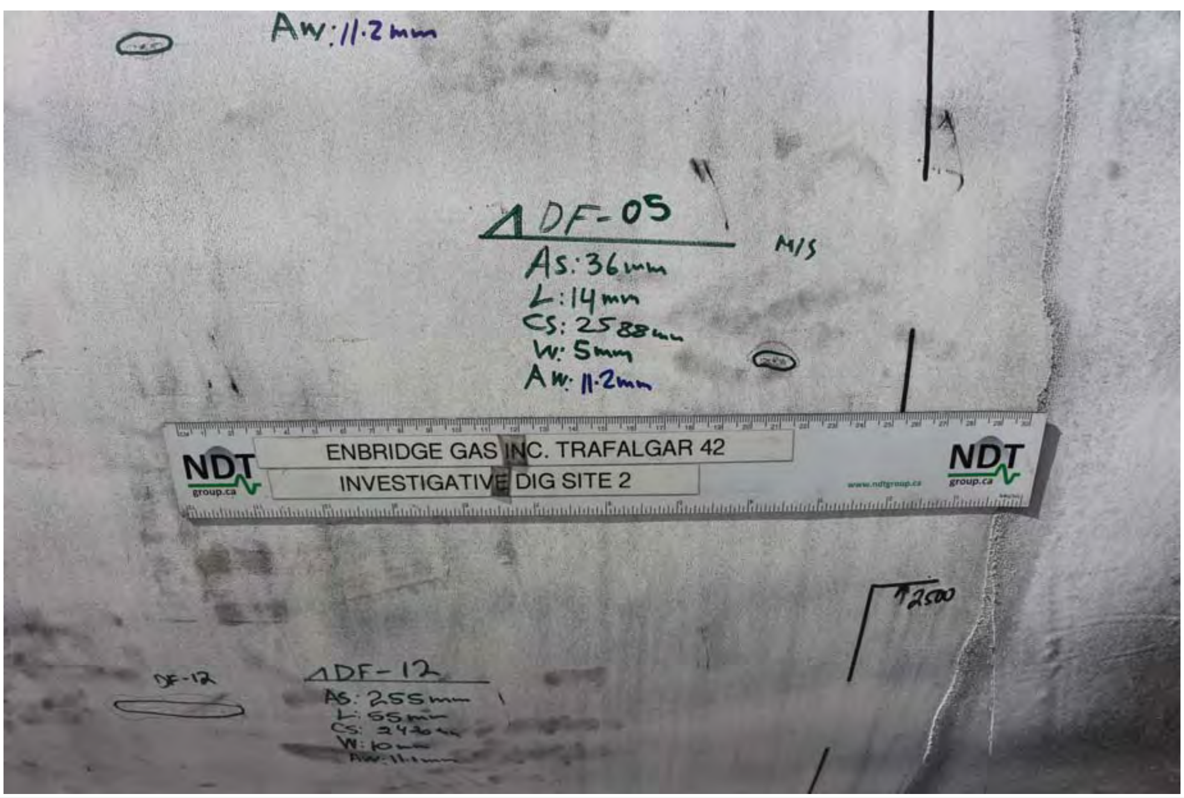


052 - DF-04

ENBRIDGE GAS INC. - TRAFALGAR NPS42

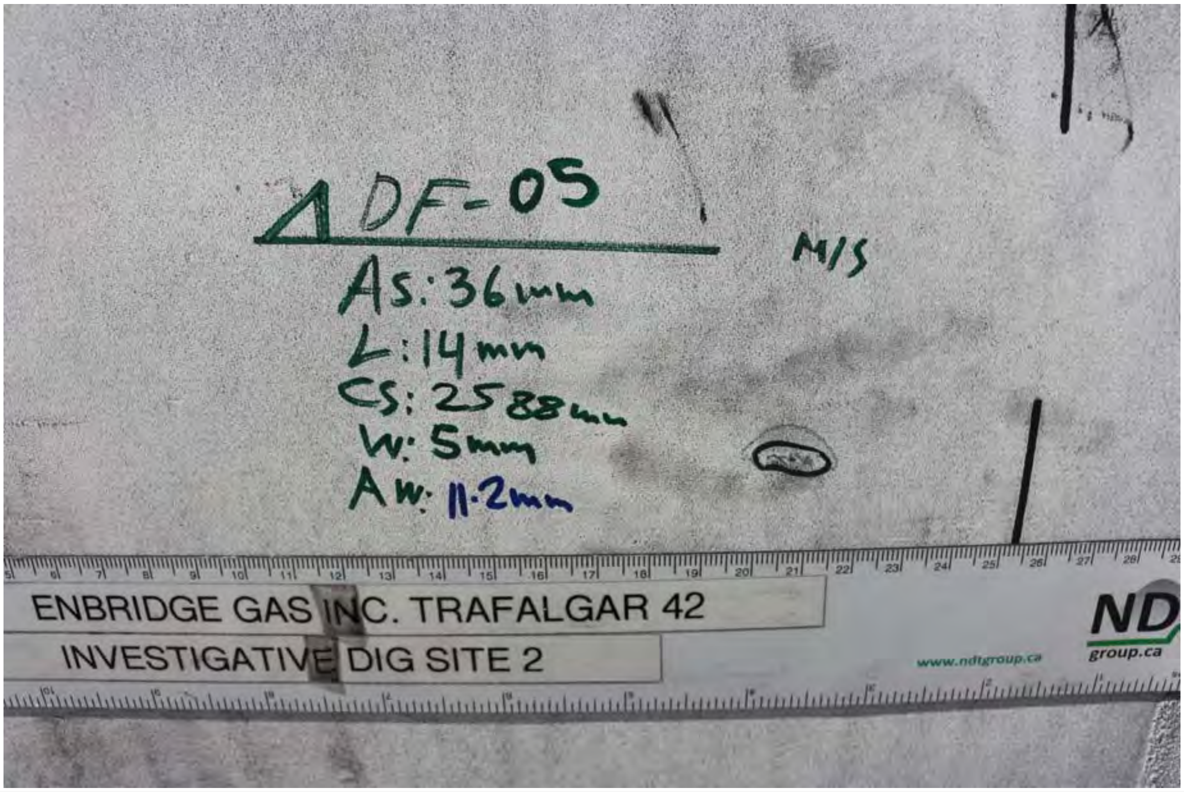


053 - DF-04 CLOSE UP

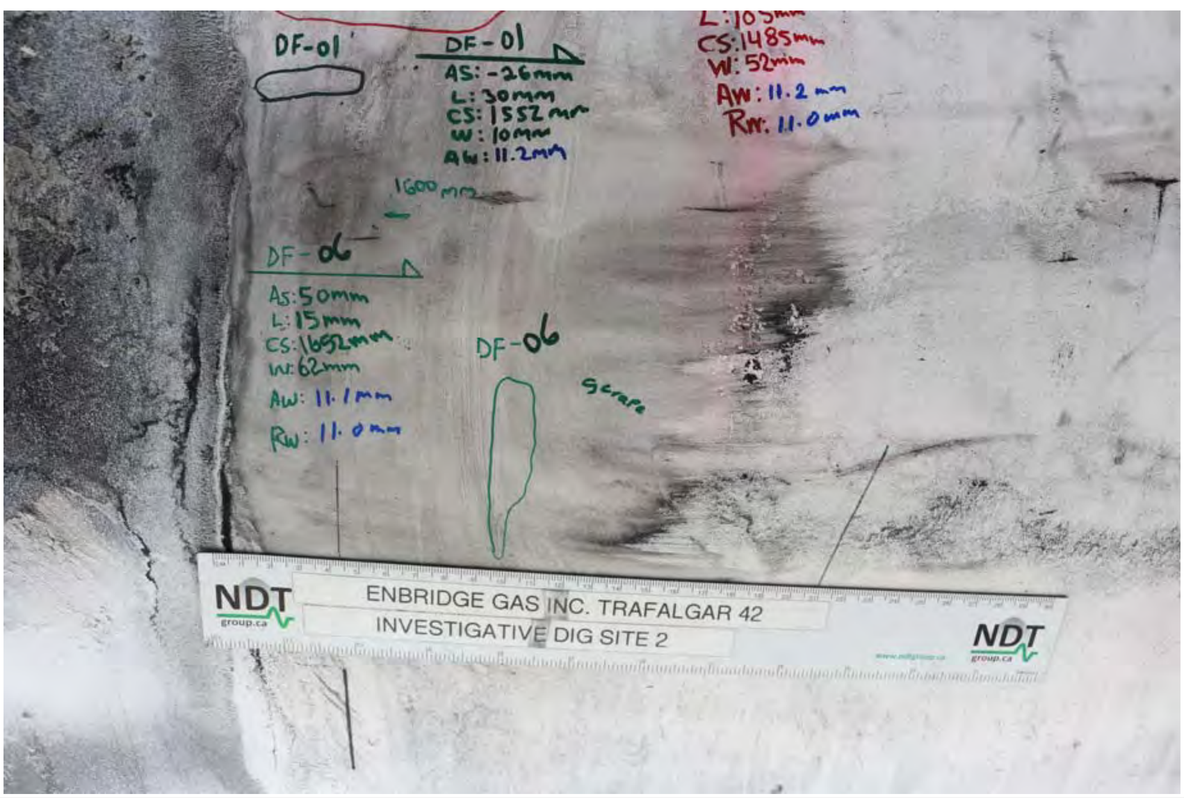


054 - DF-05

ENBRIDGE GAS INC. - TRAFALGAR NPS42

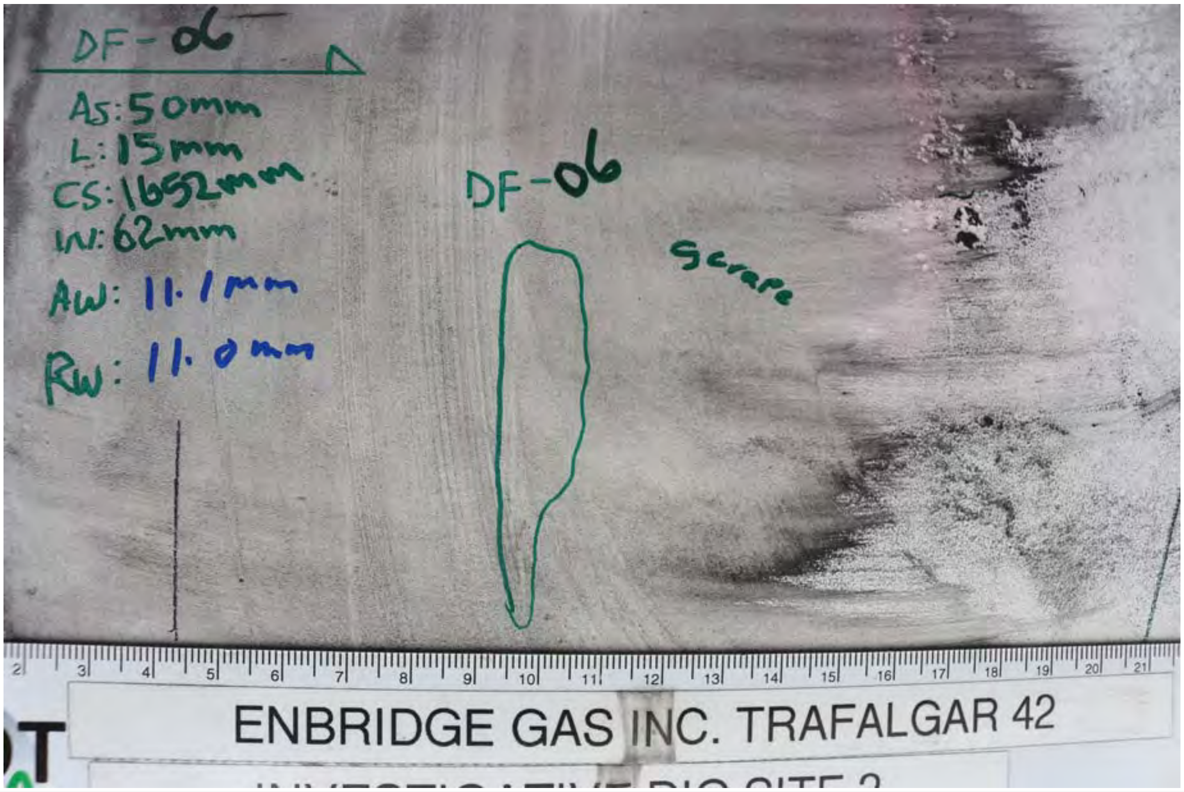


055 - DF-05 CLOSE UP

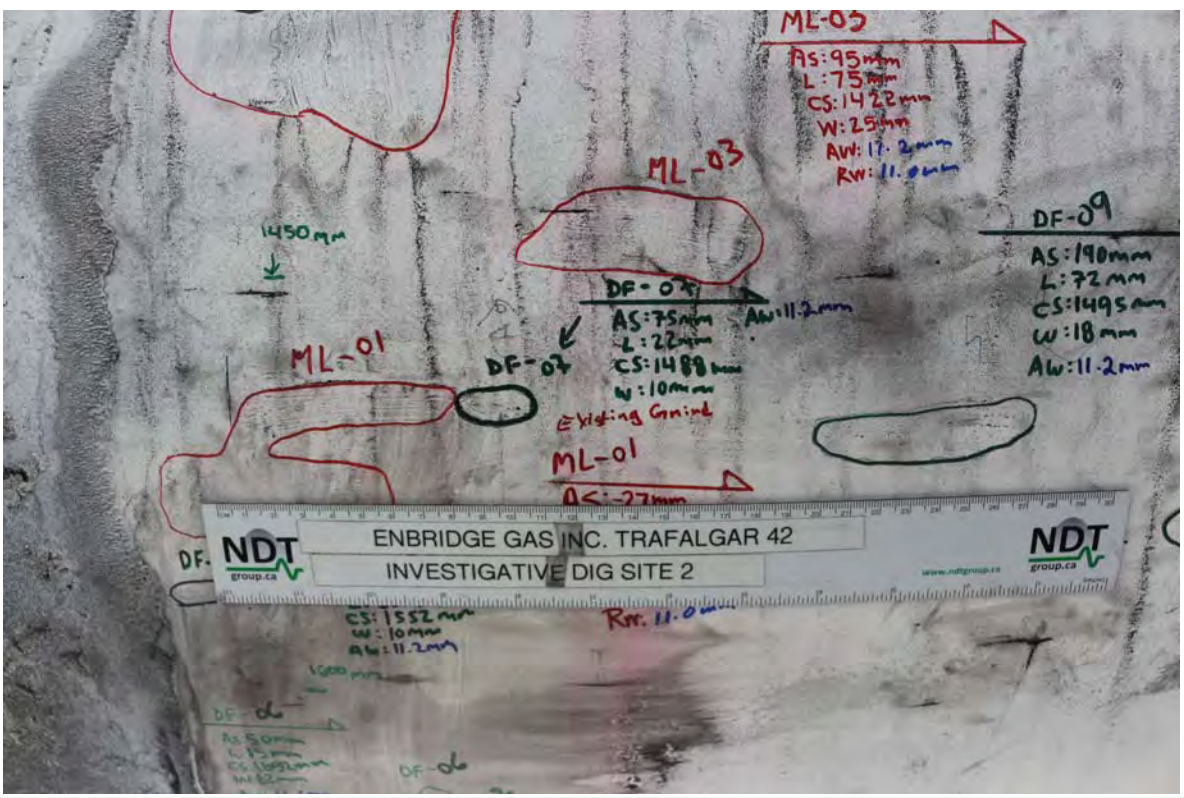


056 - DF-06

ENBRIDGE GAS INC. - TRAFALGAR NPS42

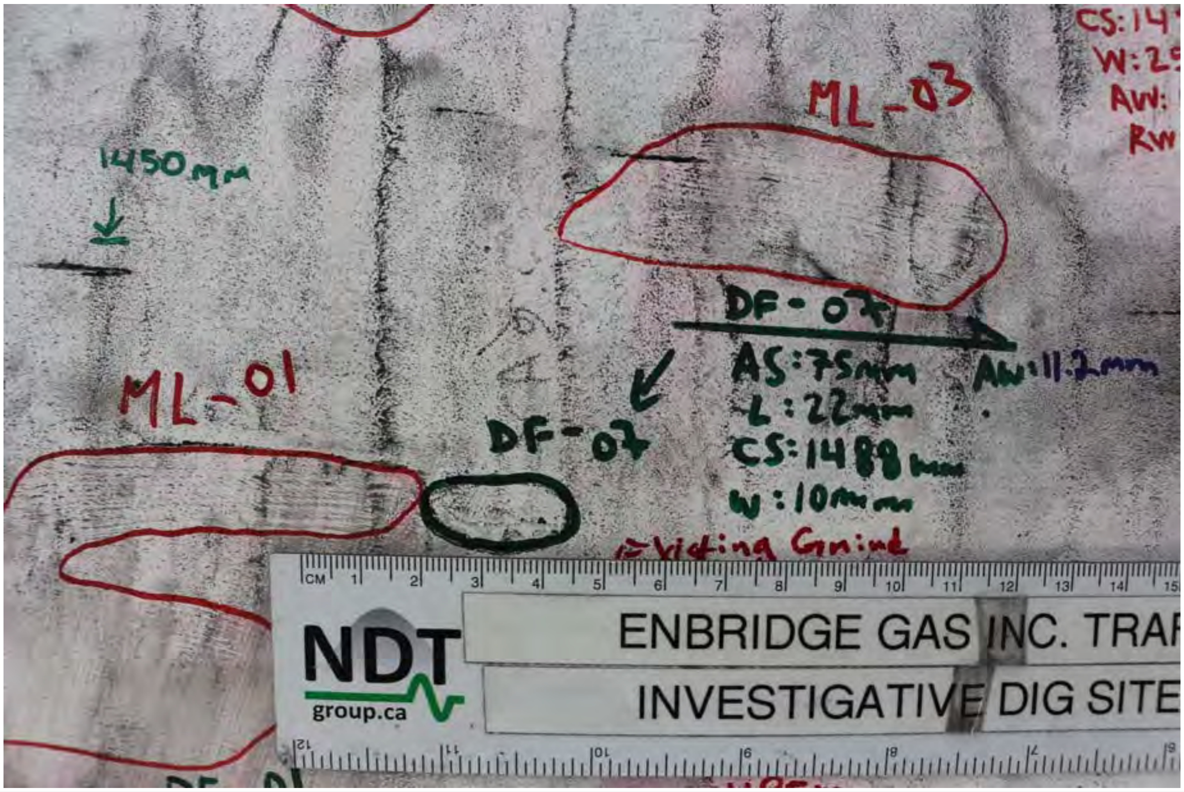


057 - DF-06 CLOSE UP

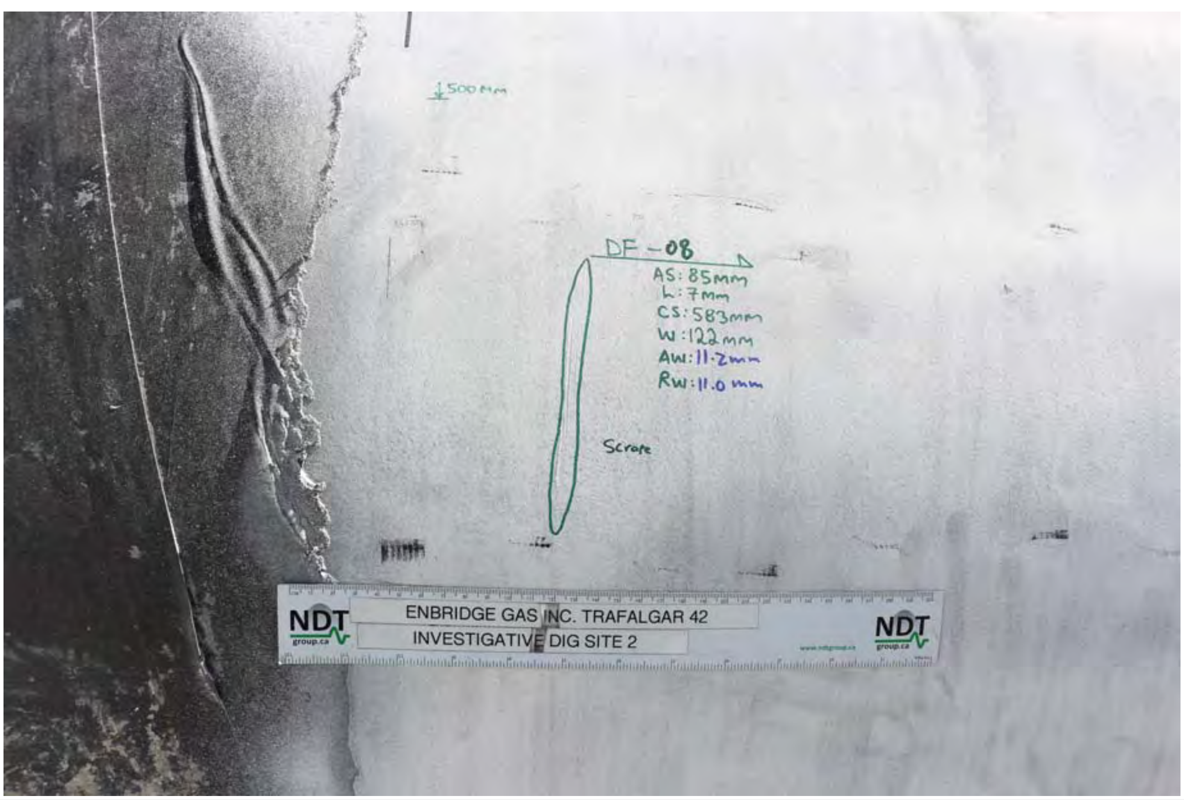


058 - DF-07

ENBRIDGE GAS INC. - TRAFALGAR NPS42

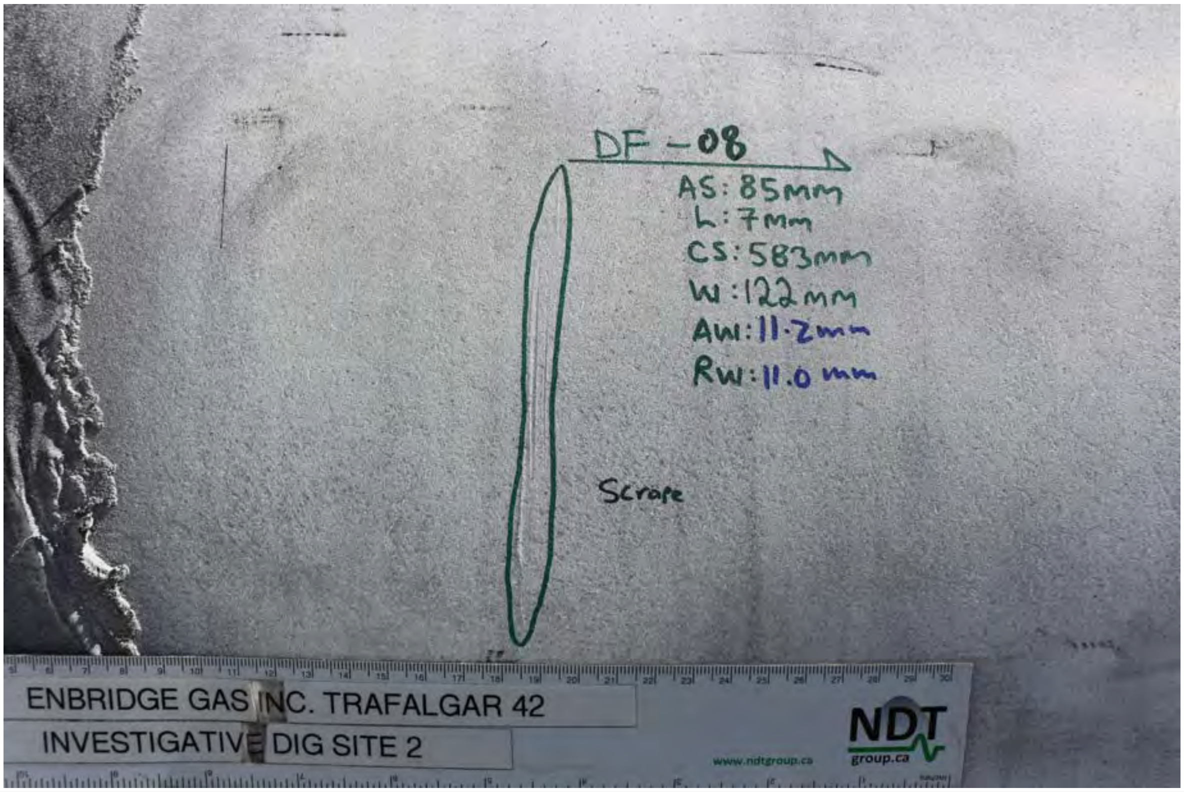


059 - DF-07 CLOSE UP

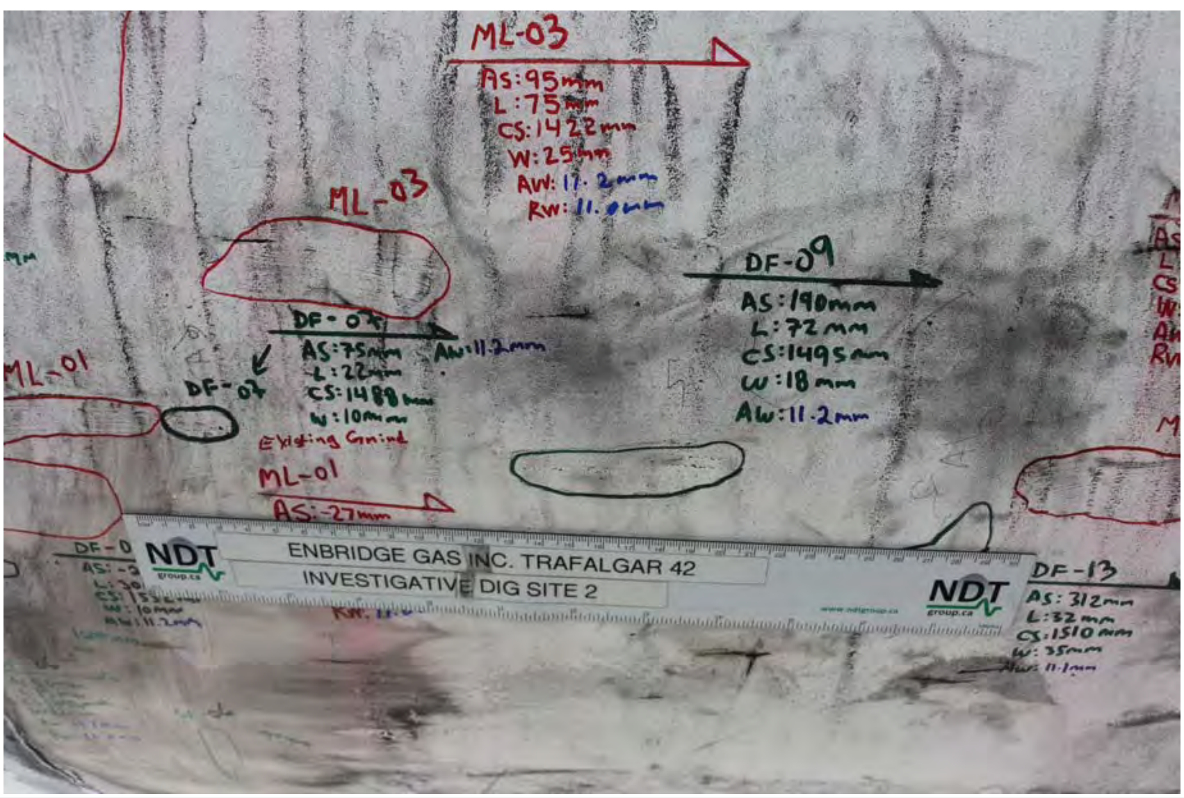


060 - DF-08

ENBRIDGE GAS INC. - TRAFALGAR NPS42

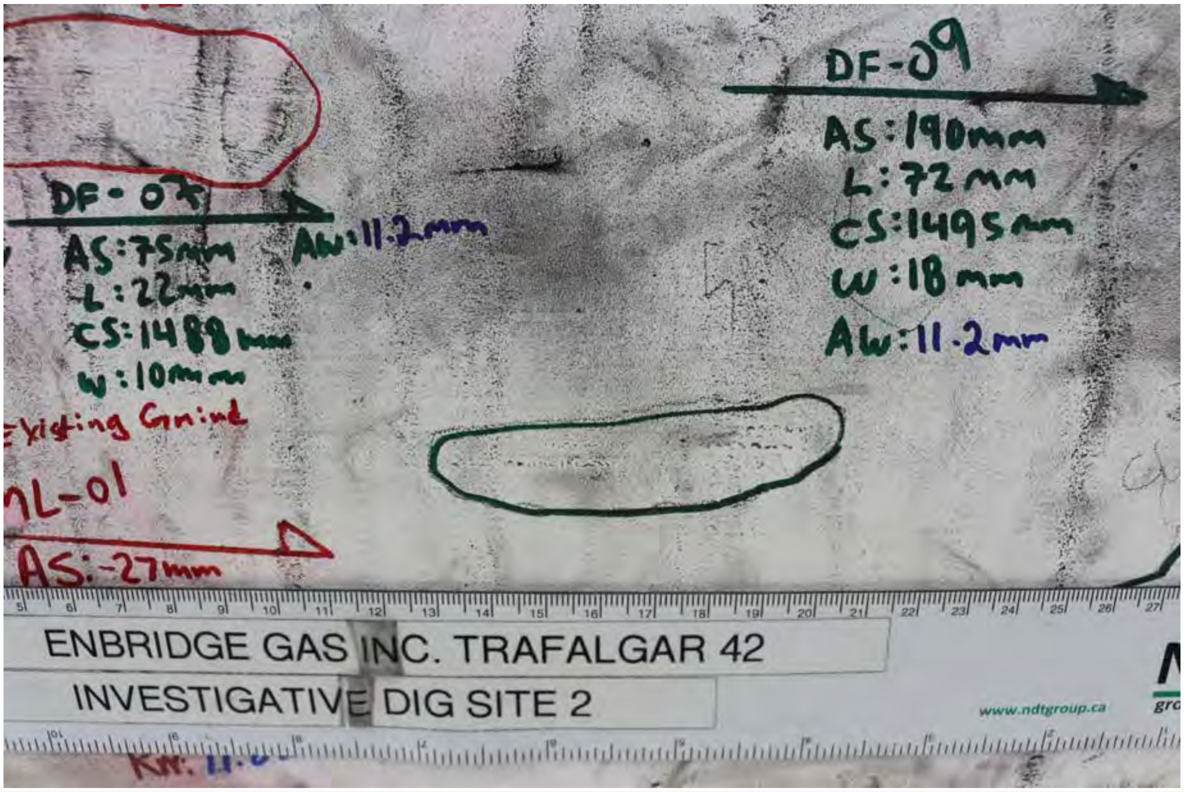


061 - DF-08 CLOSE UP

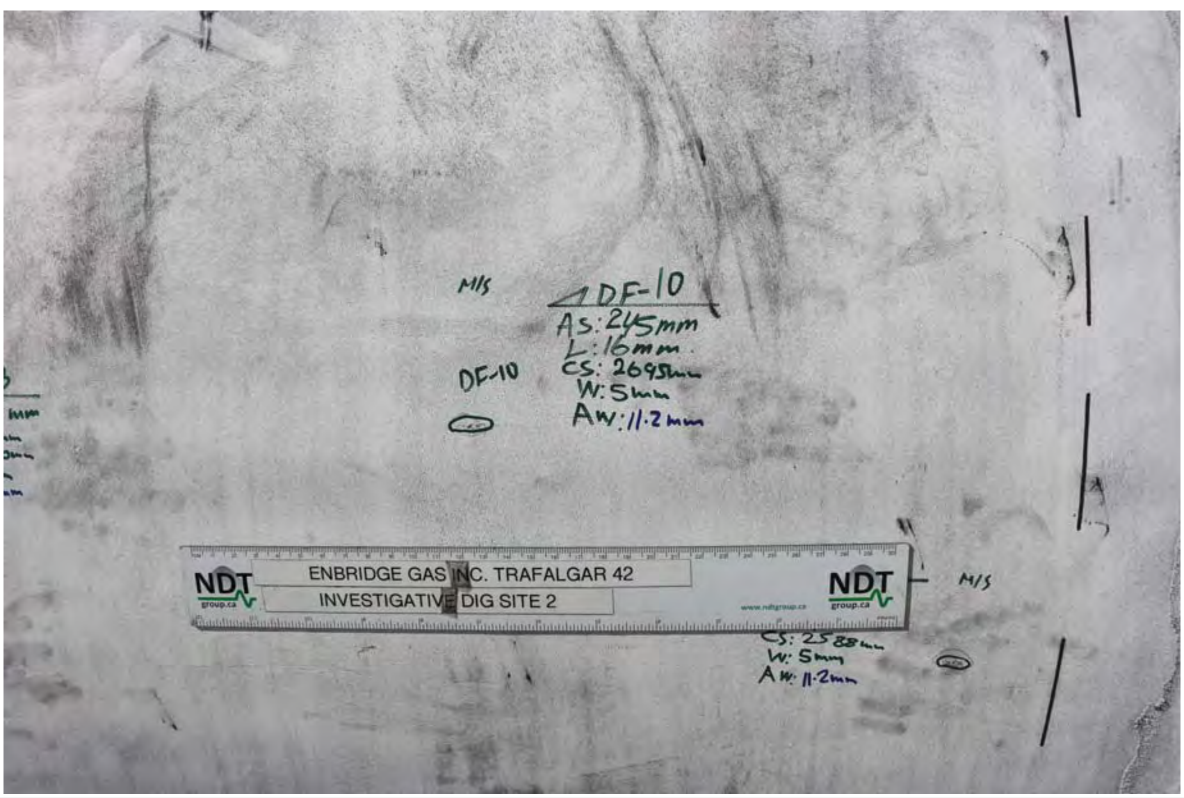


062 - DF-09

ENBRIDGE GAS INC. - TRAFALGAR NPS42

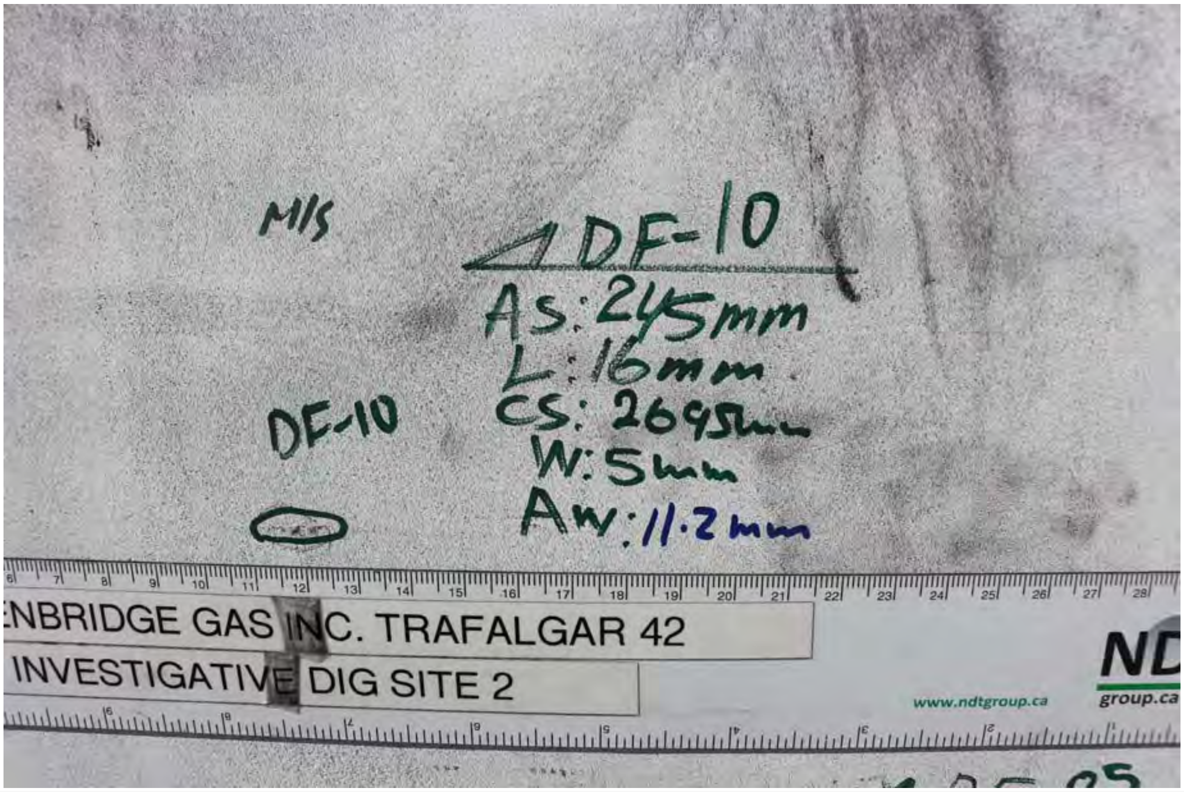


063 - DF-09 CLOSE UP

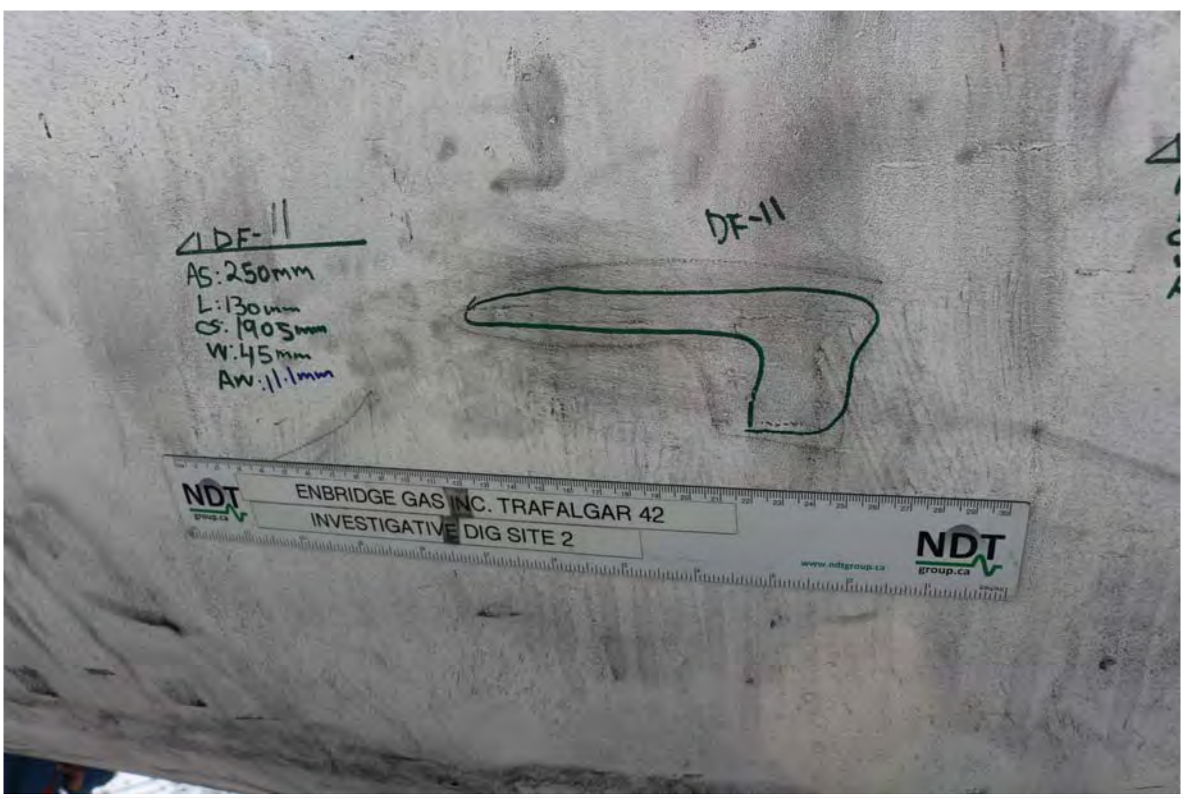


064 - DF-10

ENBRIDGE GAS INC. - TRAFALGAR NPS42



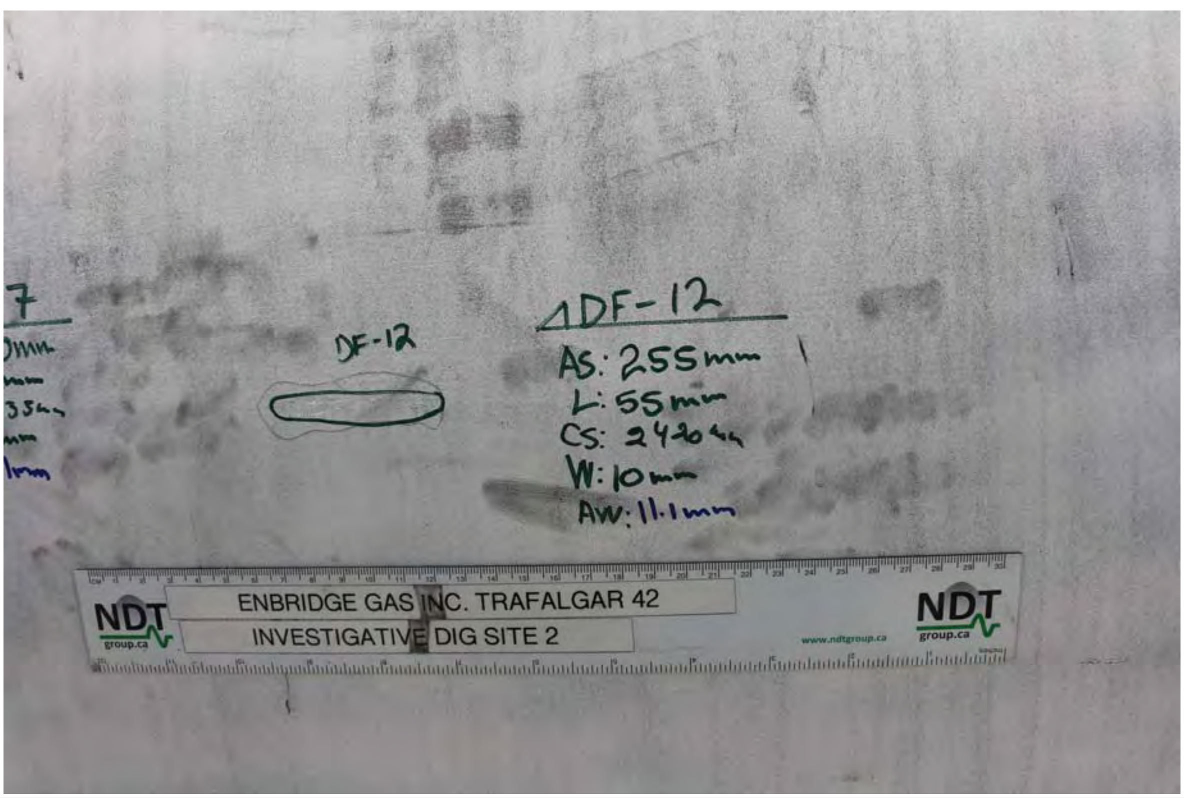
065 - DF-10 CLOSE UP



066 - DF-11

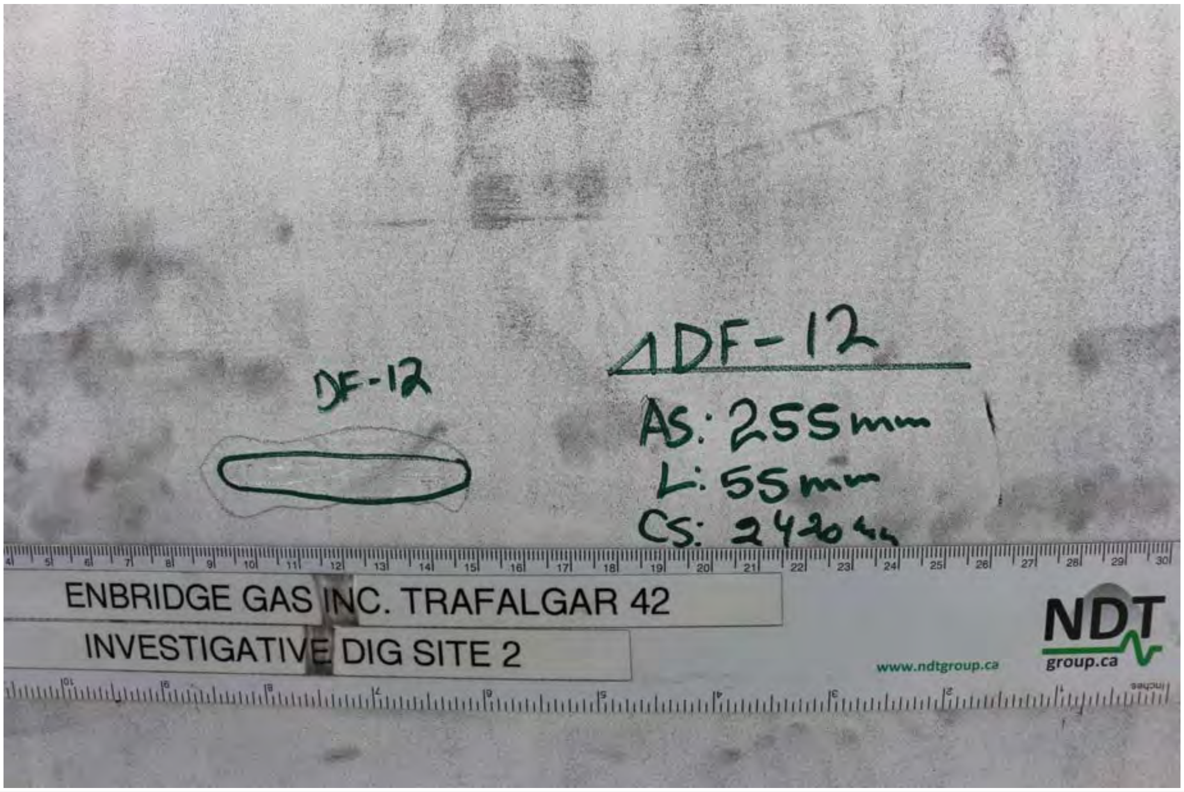
ENBRIDGE GAS INC. - TRAFALGAR NPS42

067 - DF-11 CLOSE UP

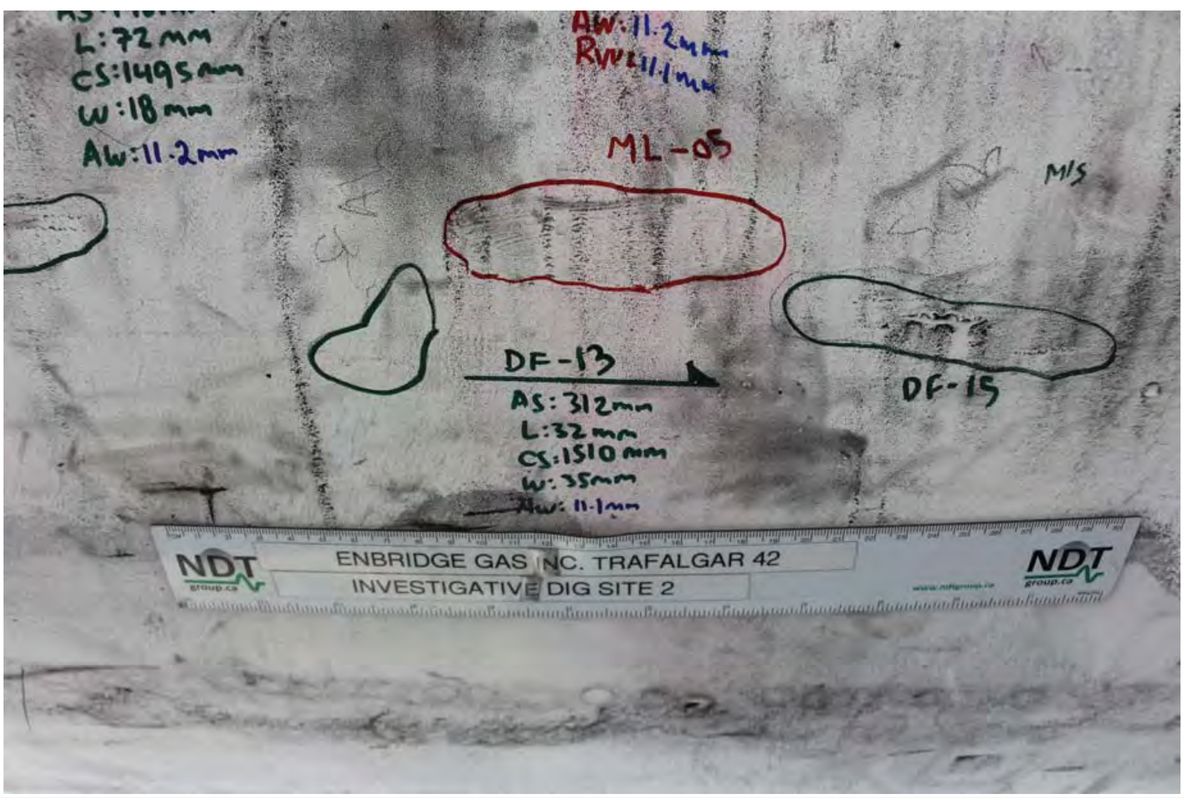


068 - DF-12

ENBRIDGE GAS INC. - TRAFALGAR NPS42

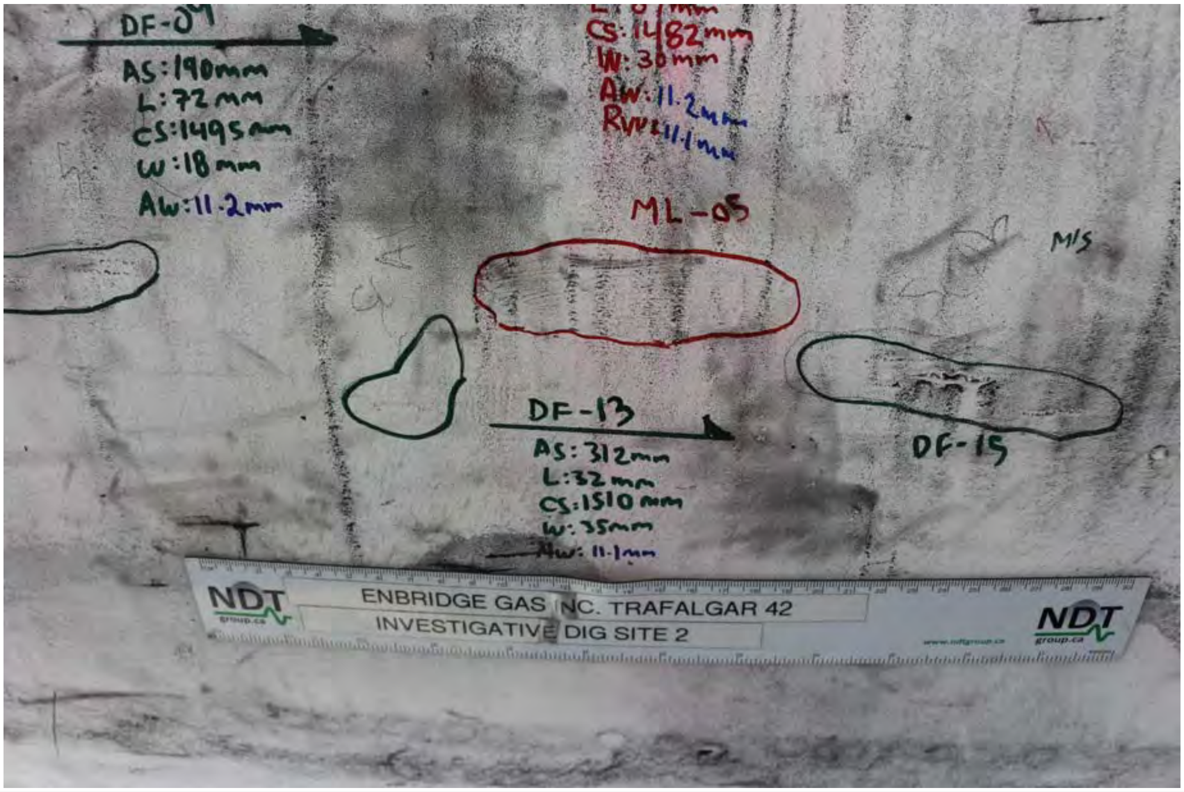


069 - DF-12 CLOSE UP

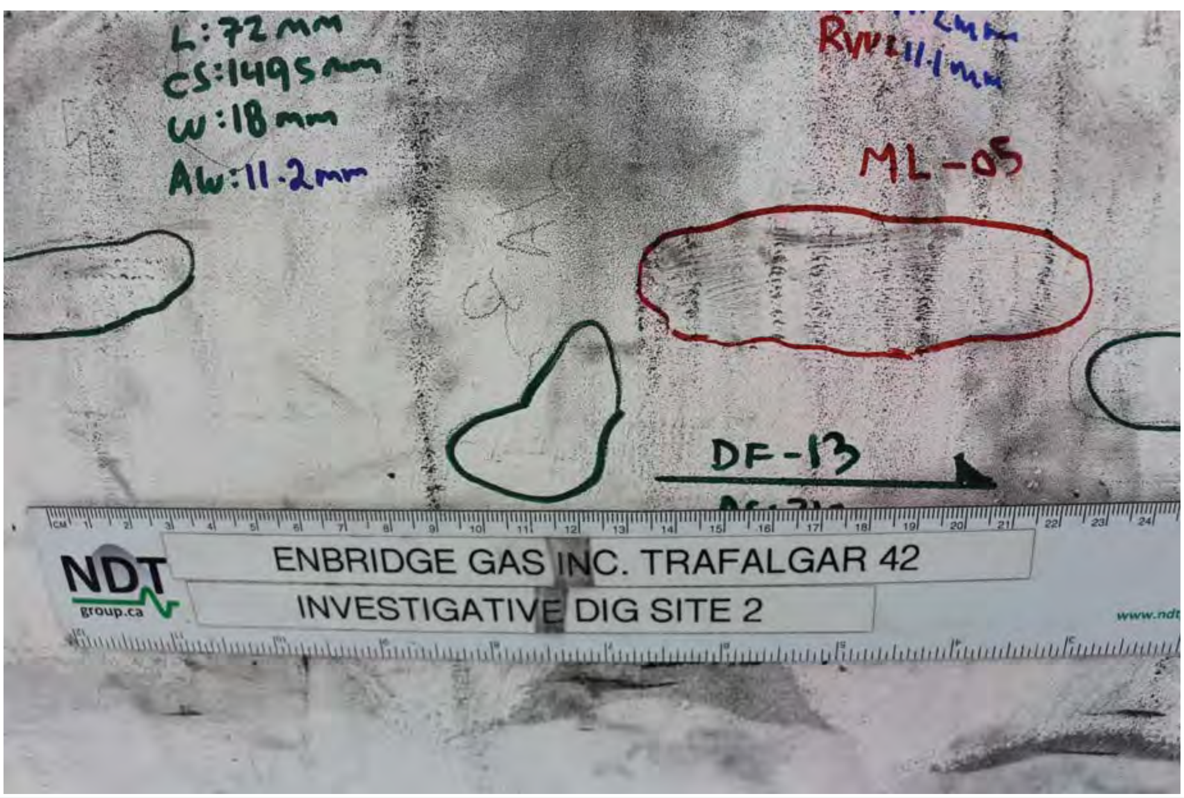


070 - DF-13

ENBRIDGE GAS INC. - TRAFALGAR NPS42

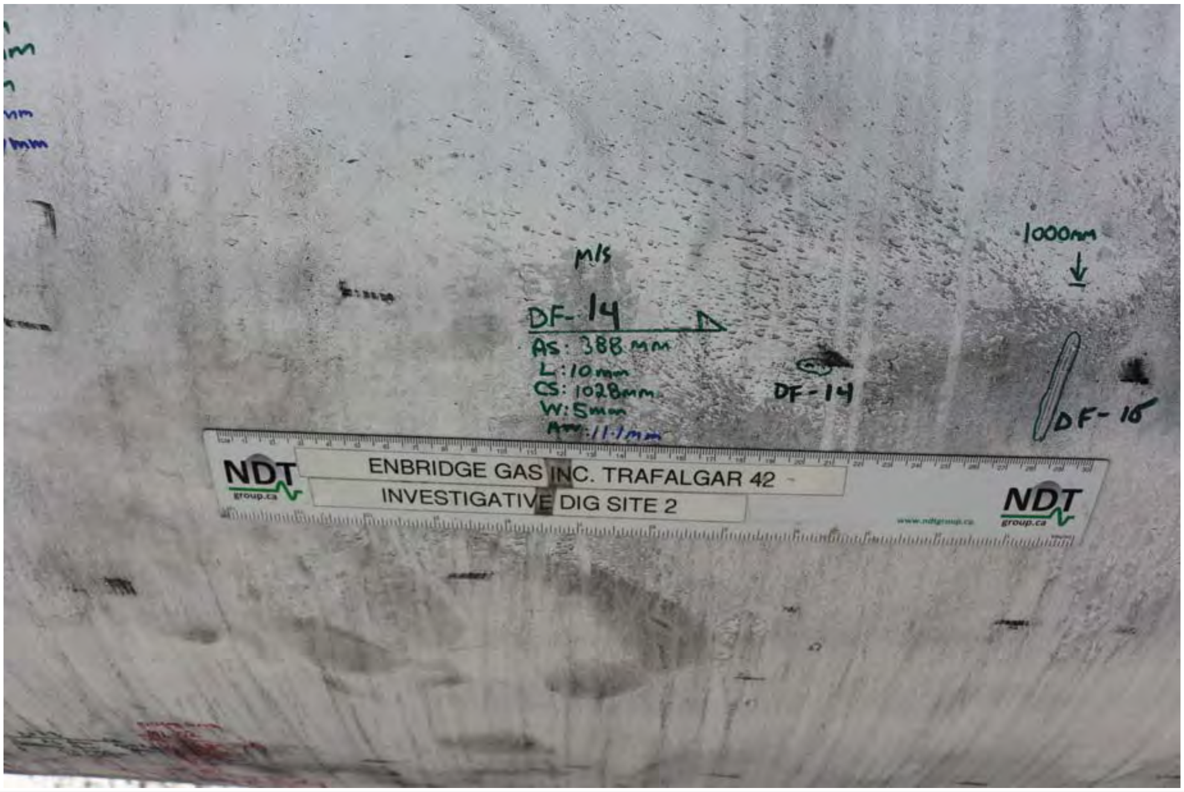


071 - DF-13 CLOSE UP

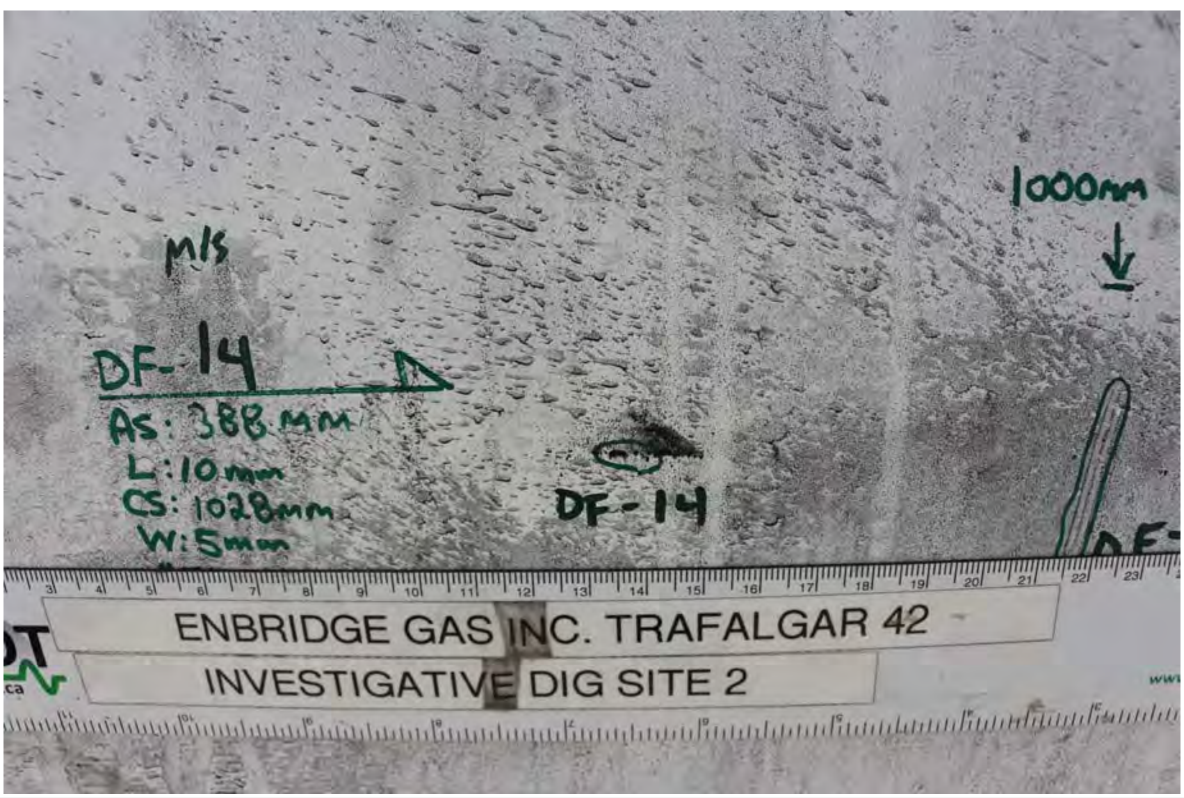


072 - DF-13 CLOSE UP (2)

ENBRIDGE GAS INC. - TRAFALGAR NPS42



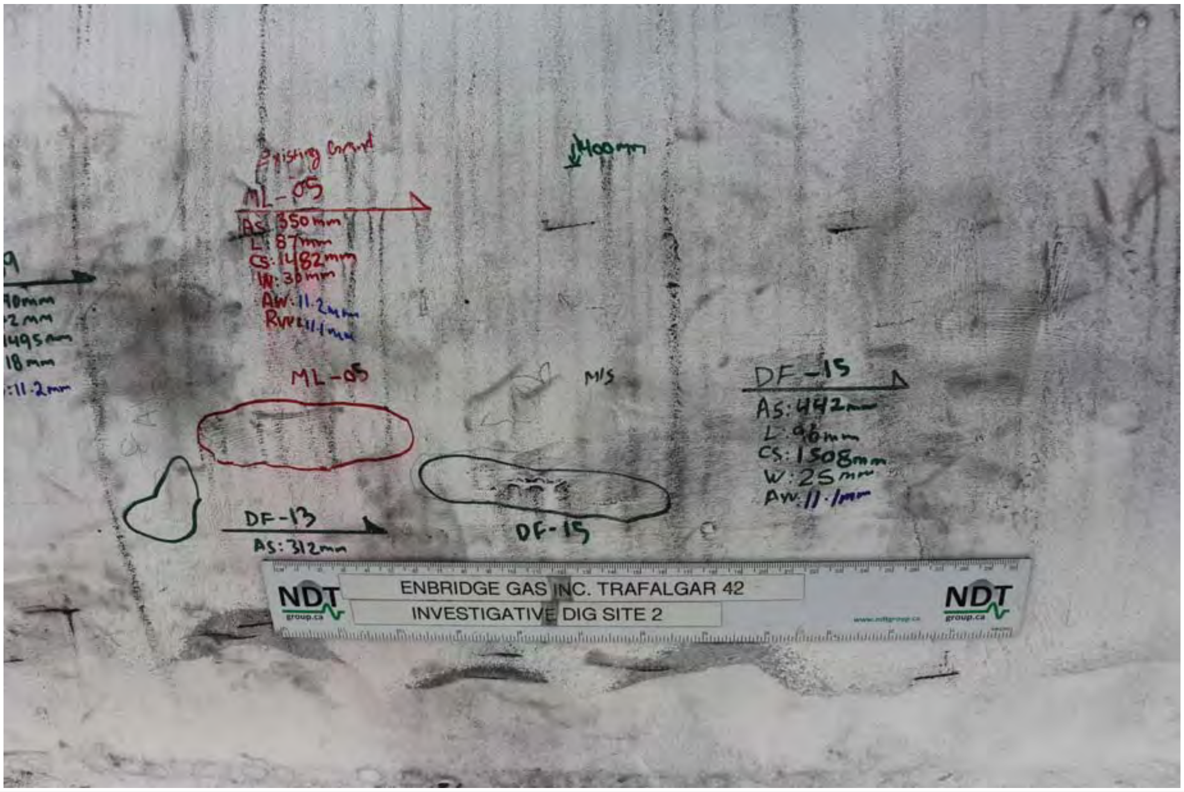
073 - DF-14



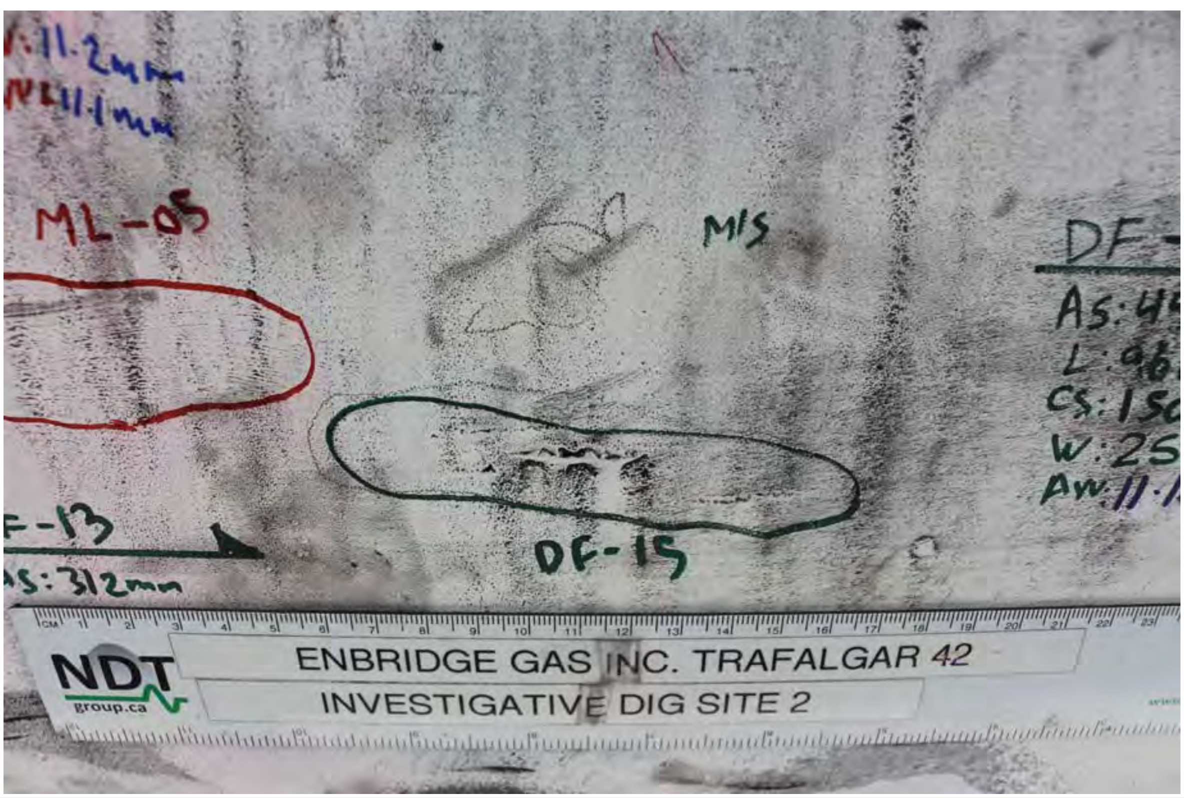
074 - DF-14 CLOSE UP

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

ENBRIDGE GAS INC. - TRAFALGAR NPS42

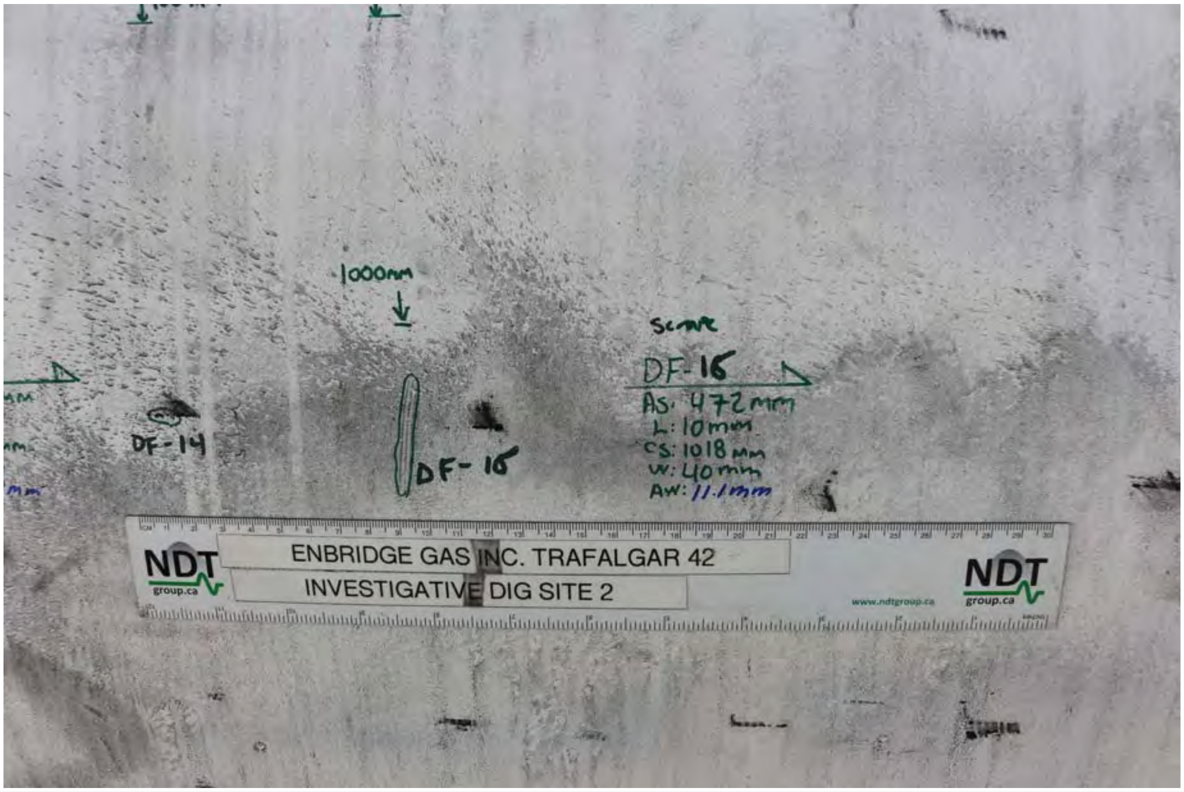


075 - DF-15

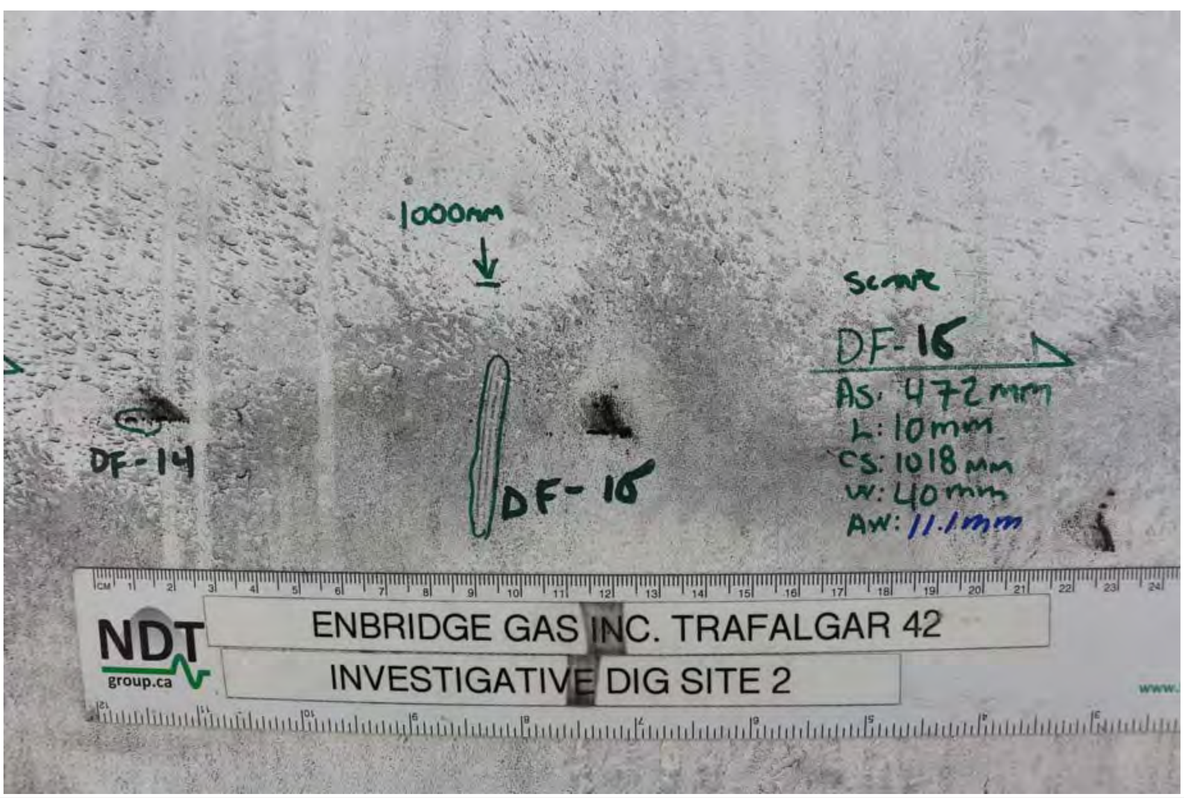


076 - DF-15 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

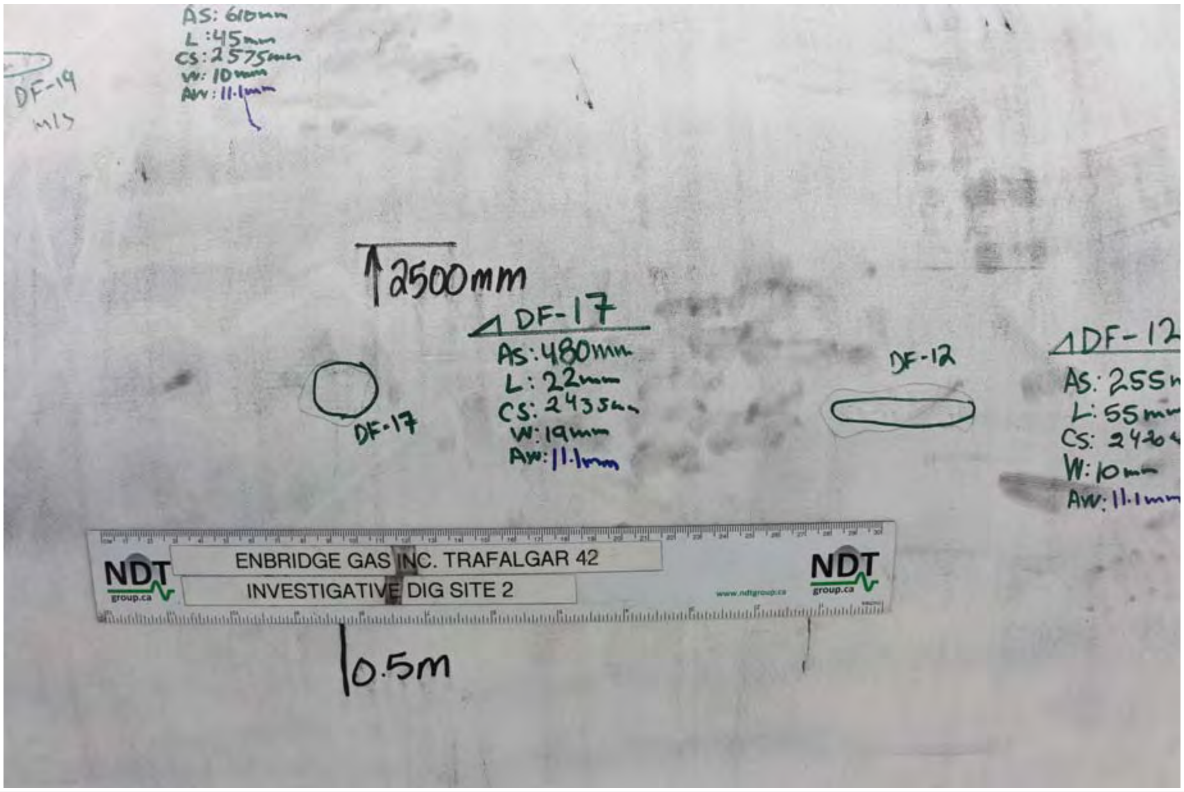


077 - DF-16

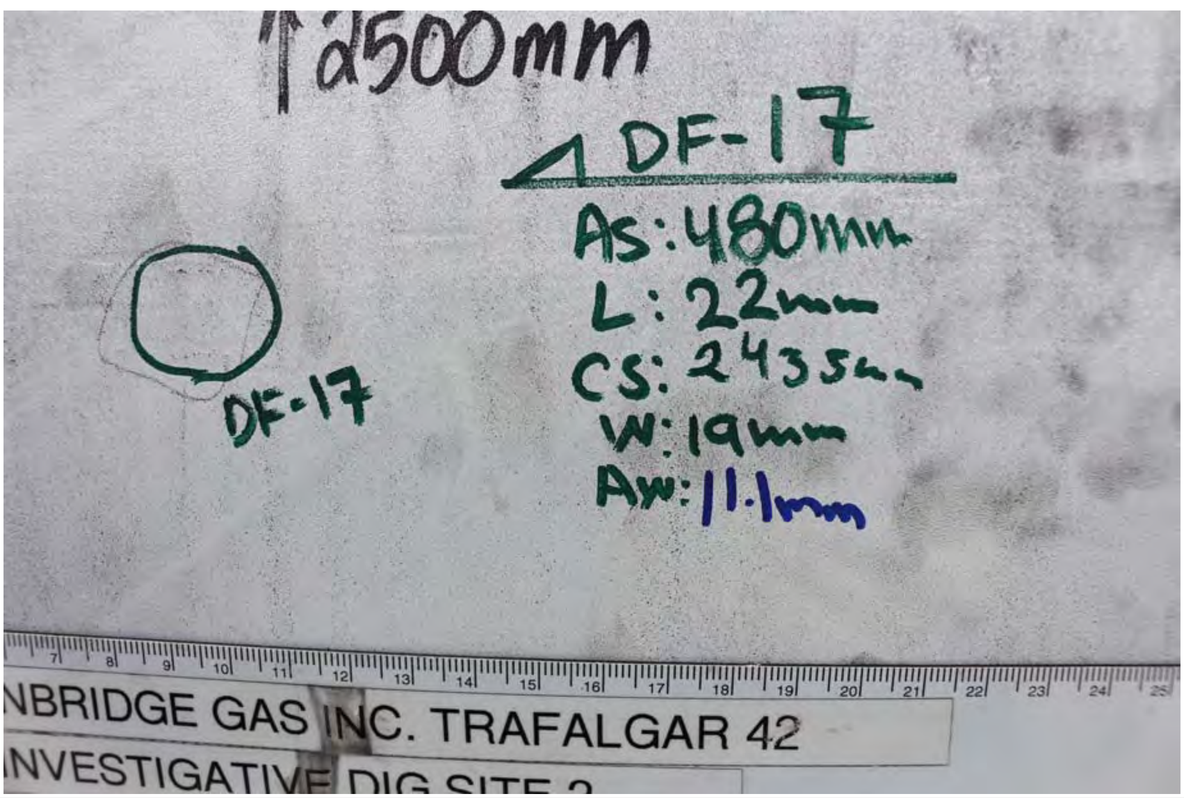


078 - DF-16 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

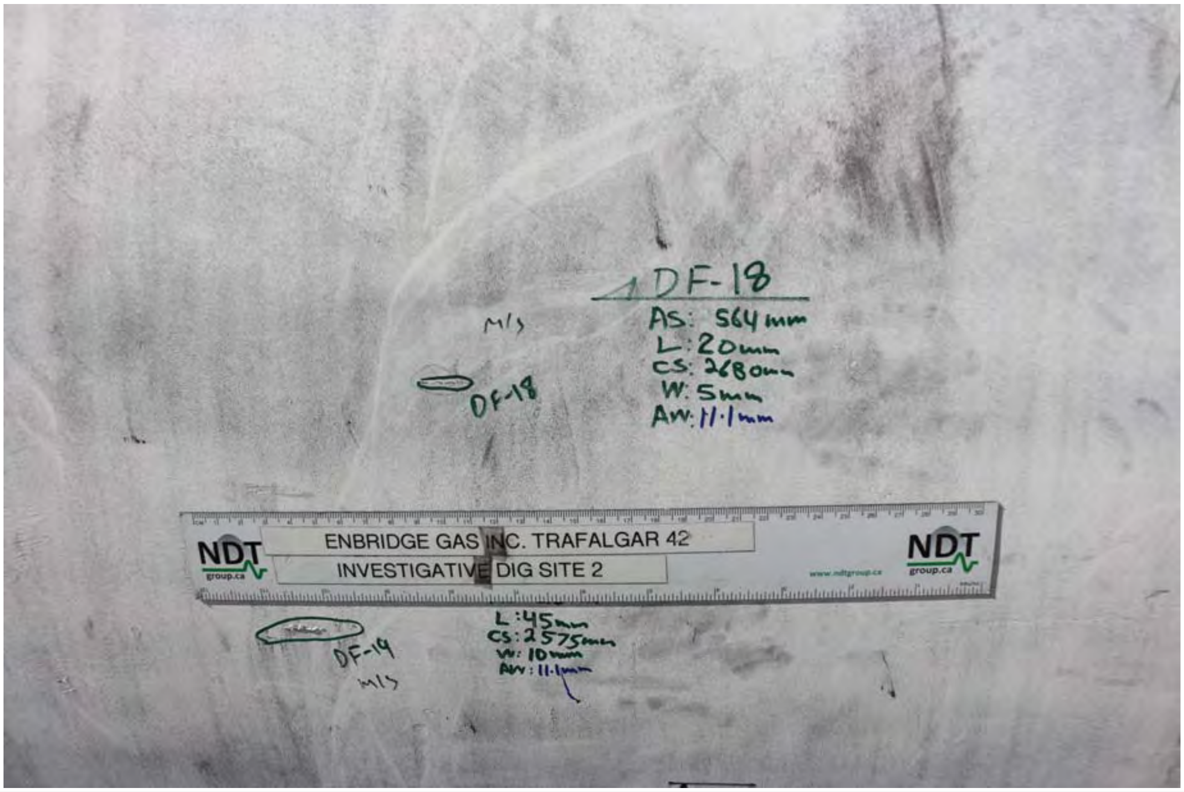


079 - DF-17

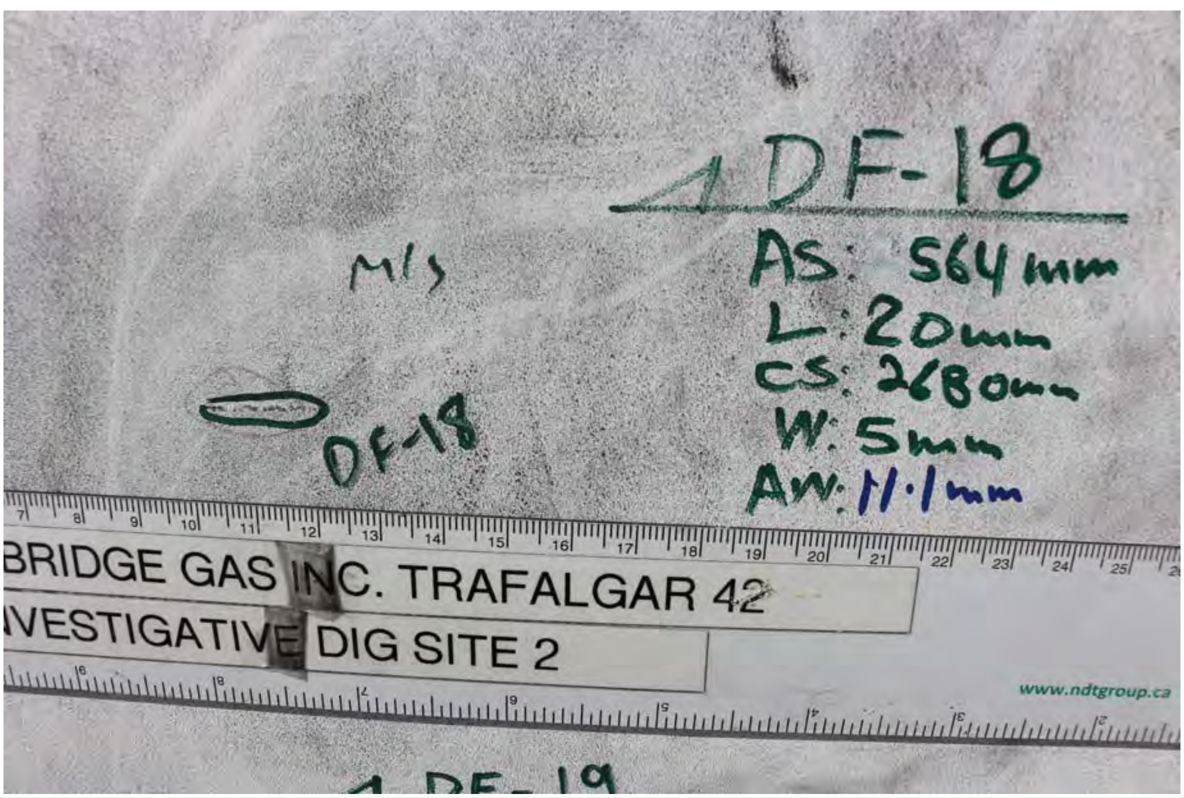


080 - DF-17 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

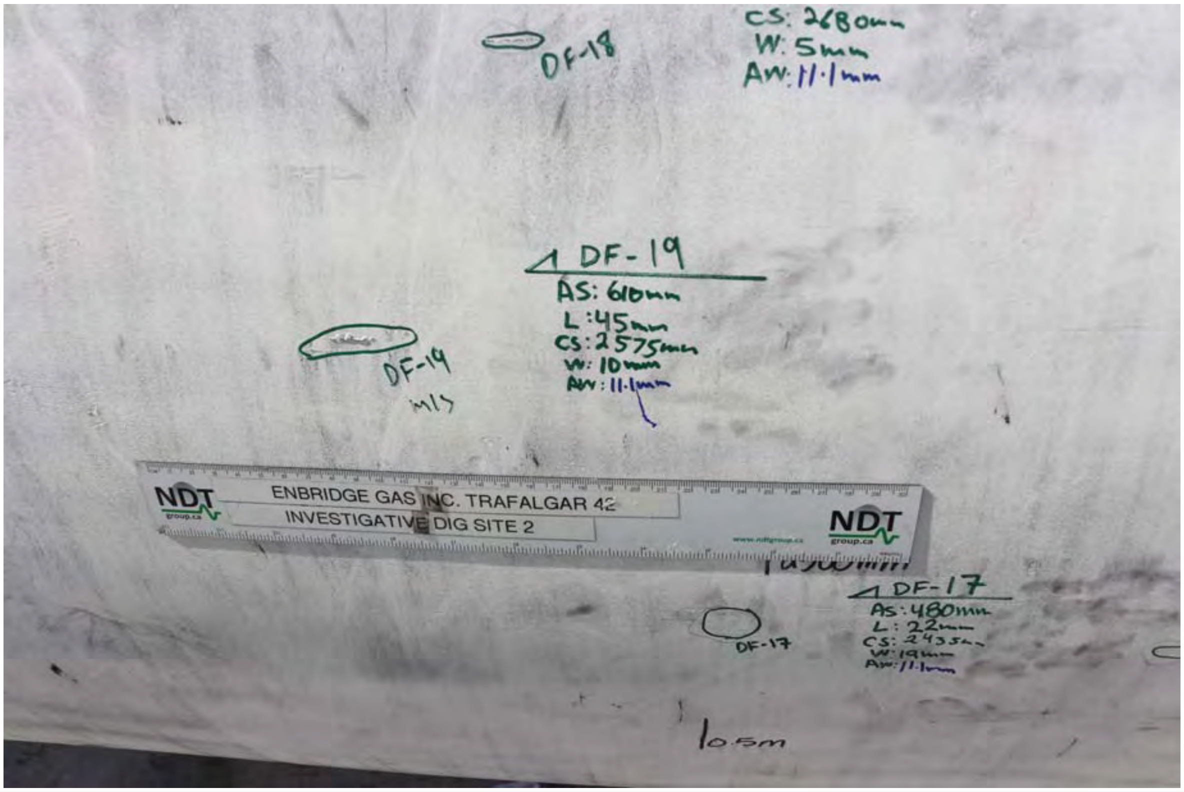


081 - DF-18

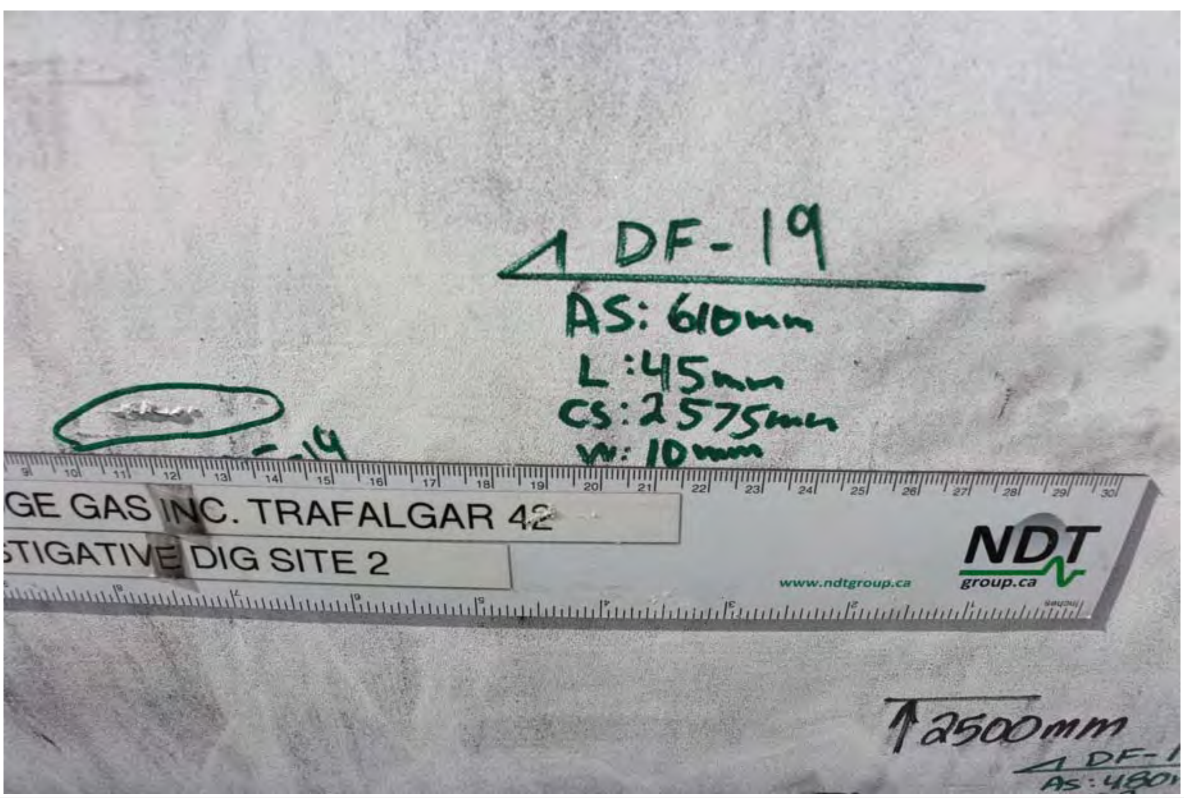


082 - DF-18 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

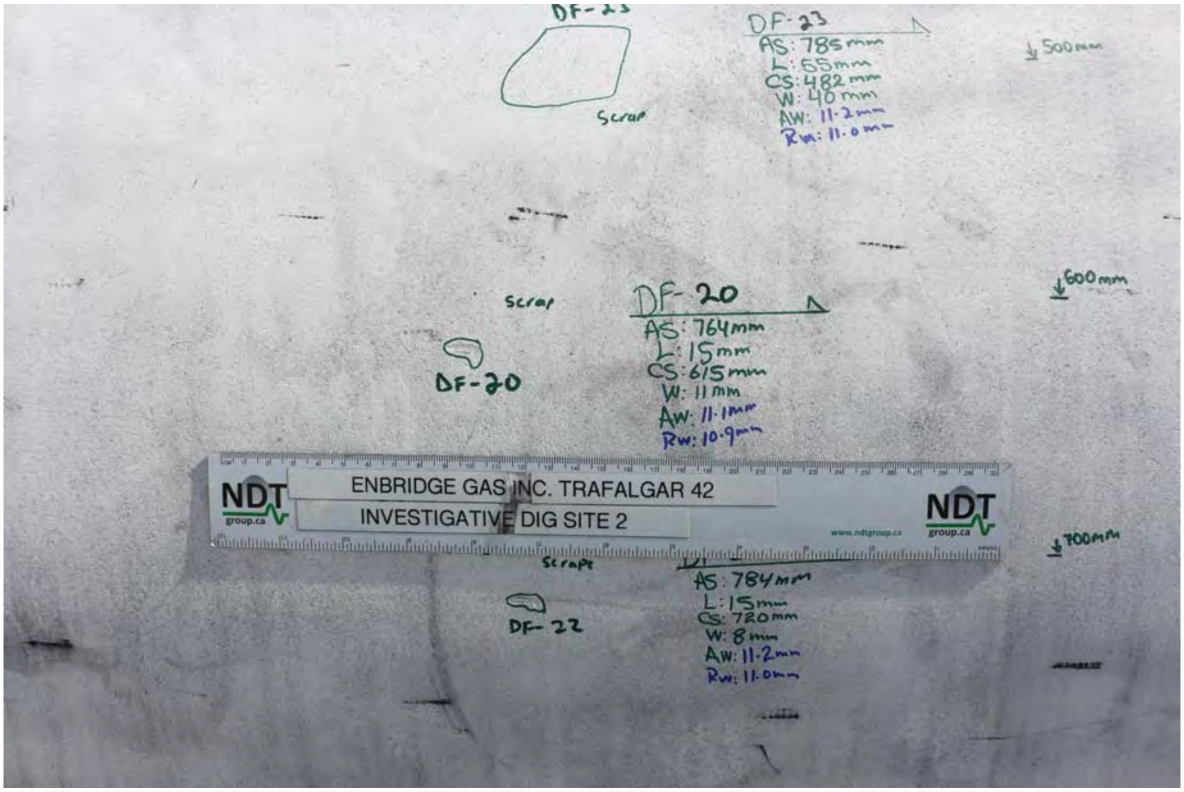


083 - DF-19

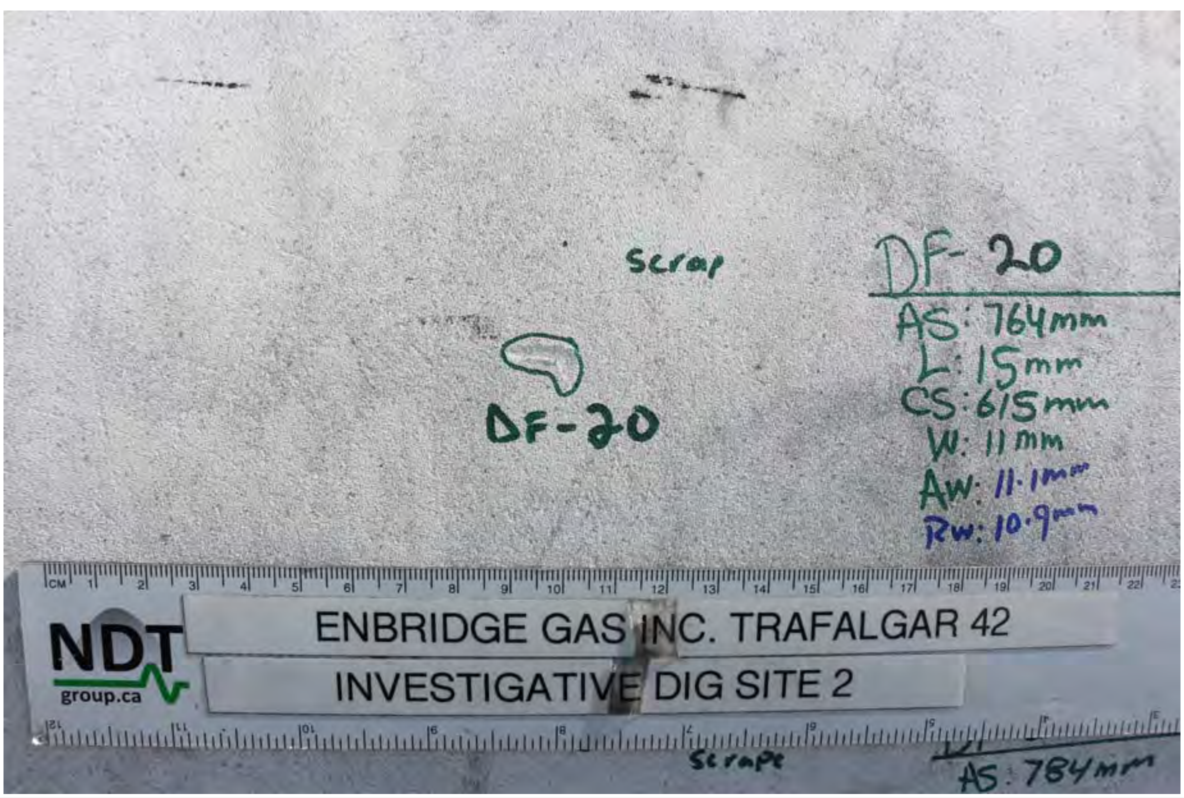


084 - DF-19 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

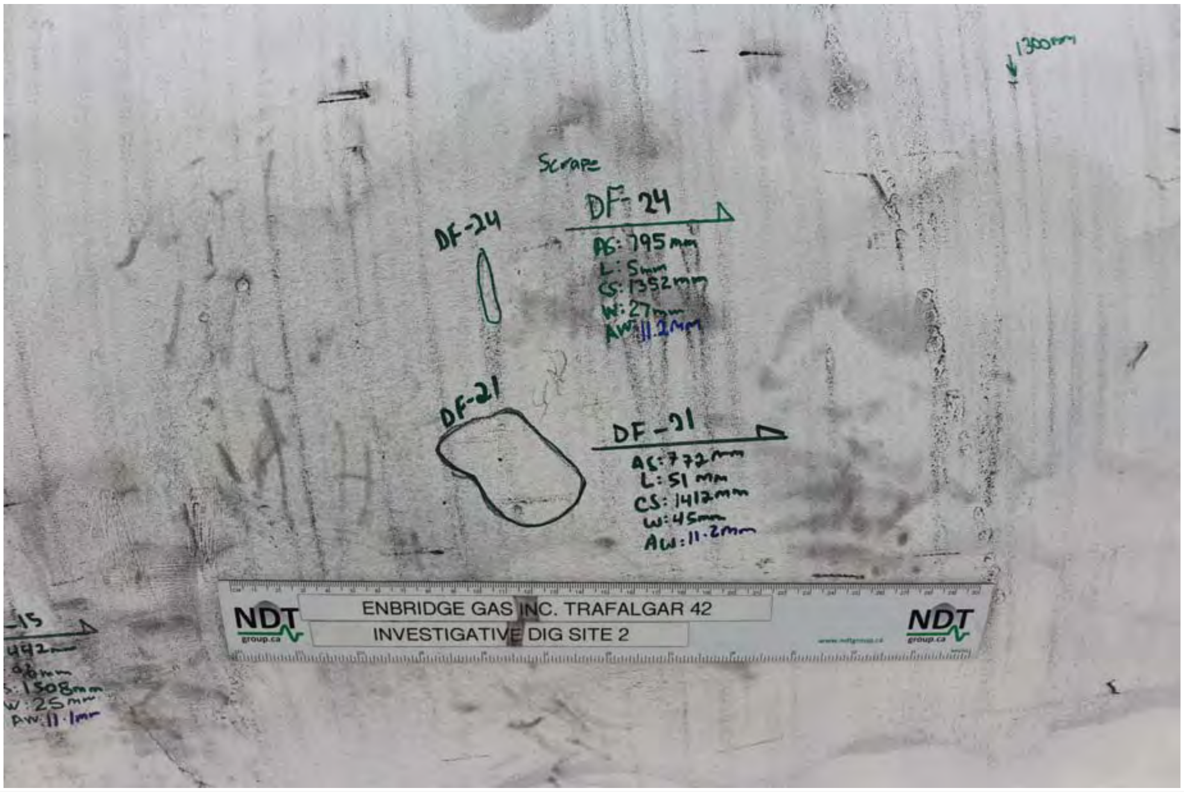


085 - DF-20

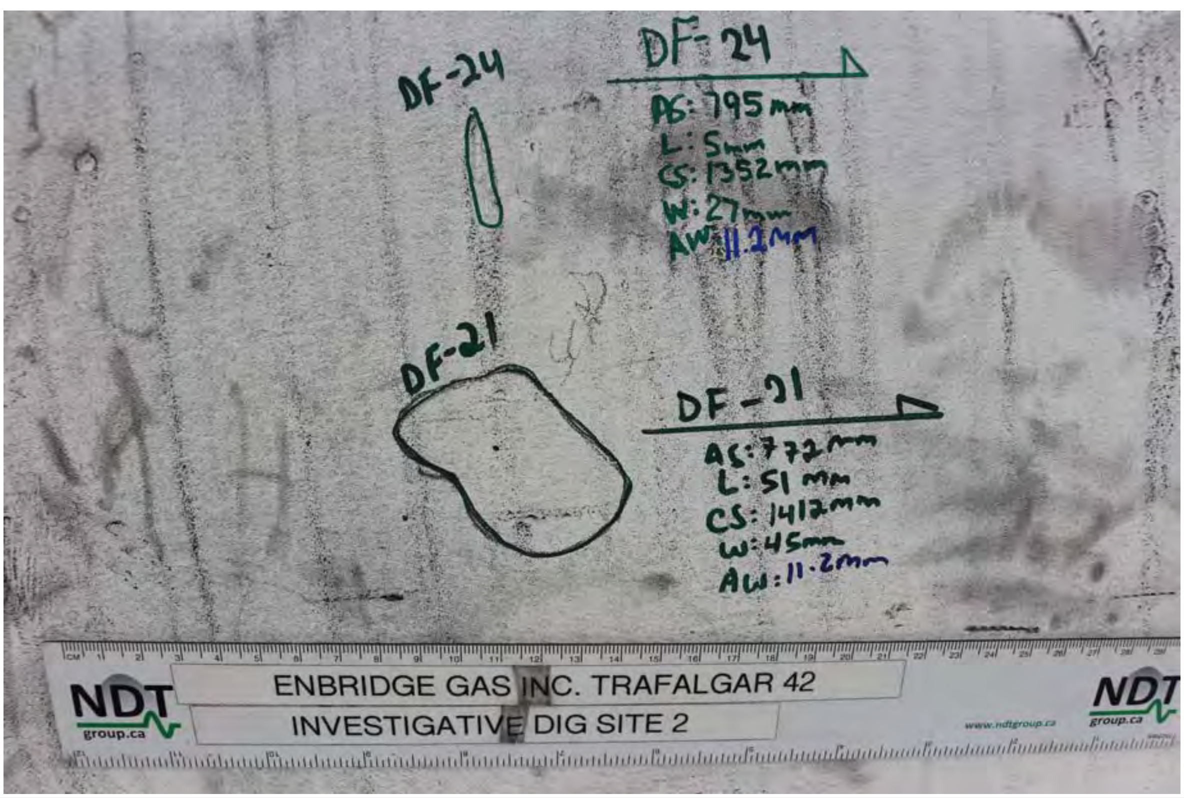


086 - DF-20 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

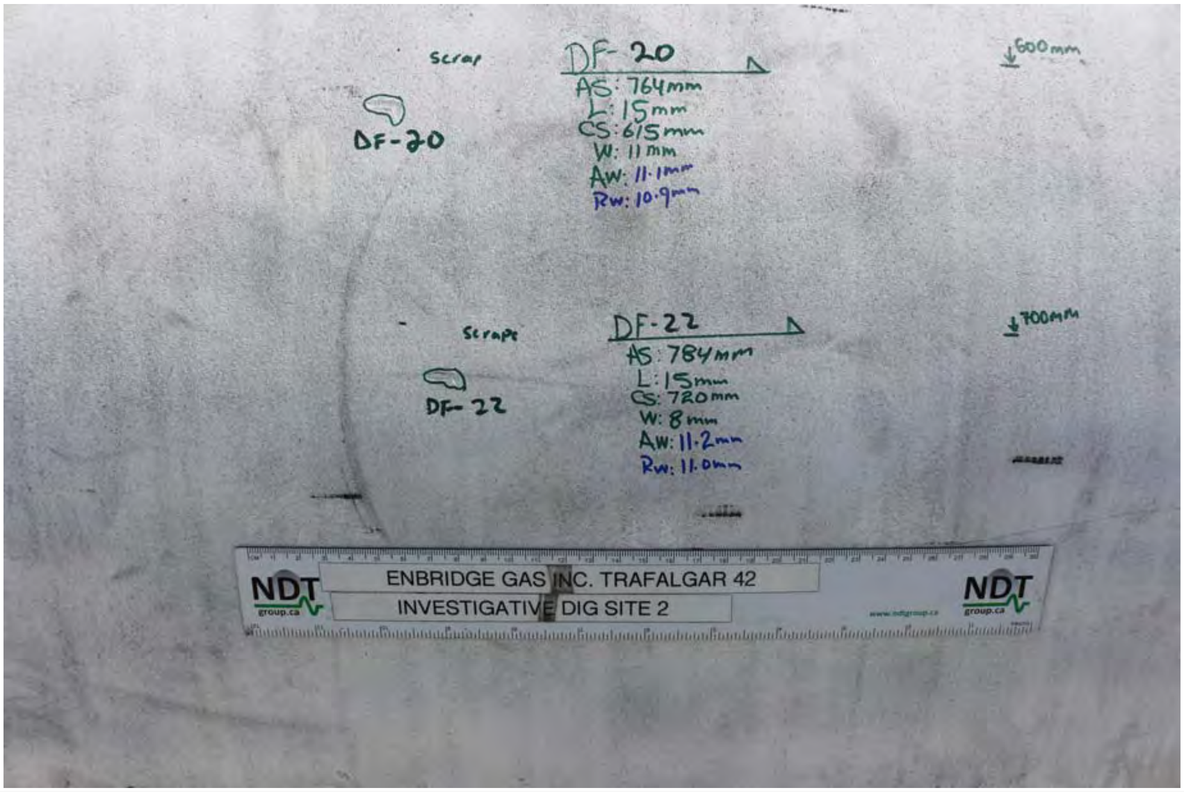


087 - DF-21

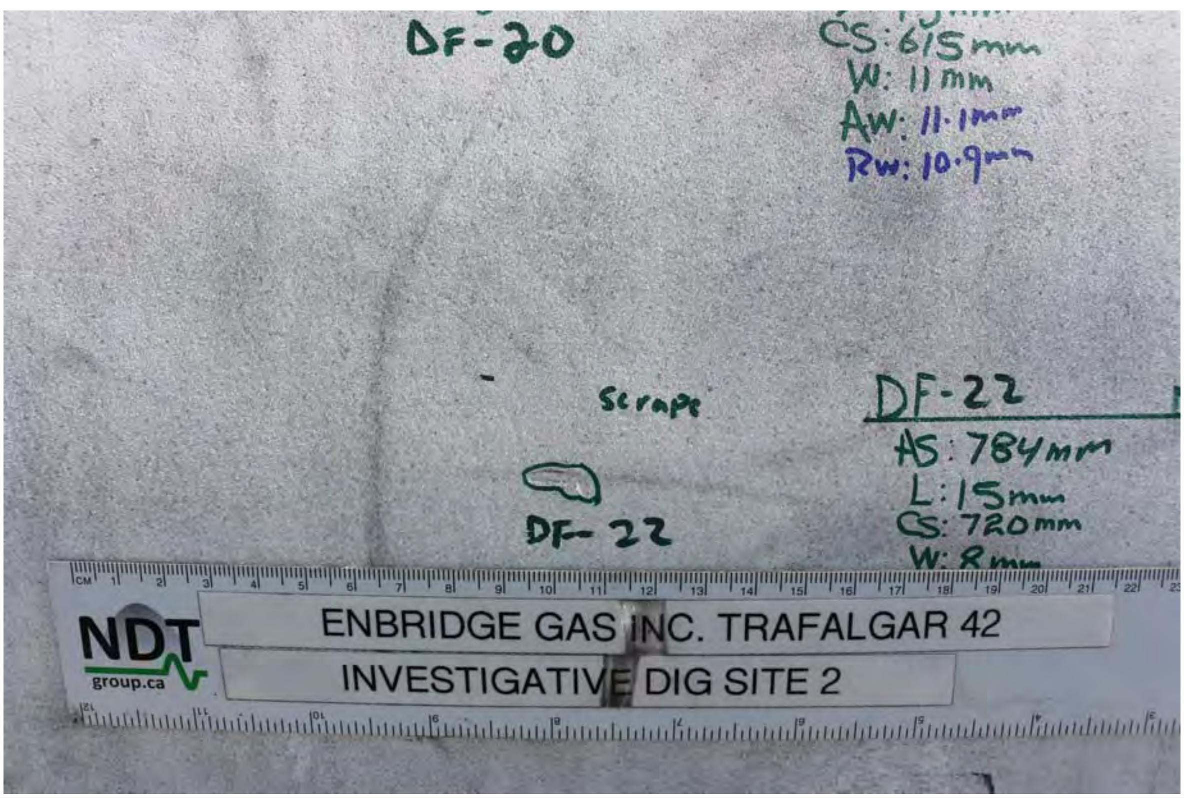


088 - DF-21 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

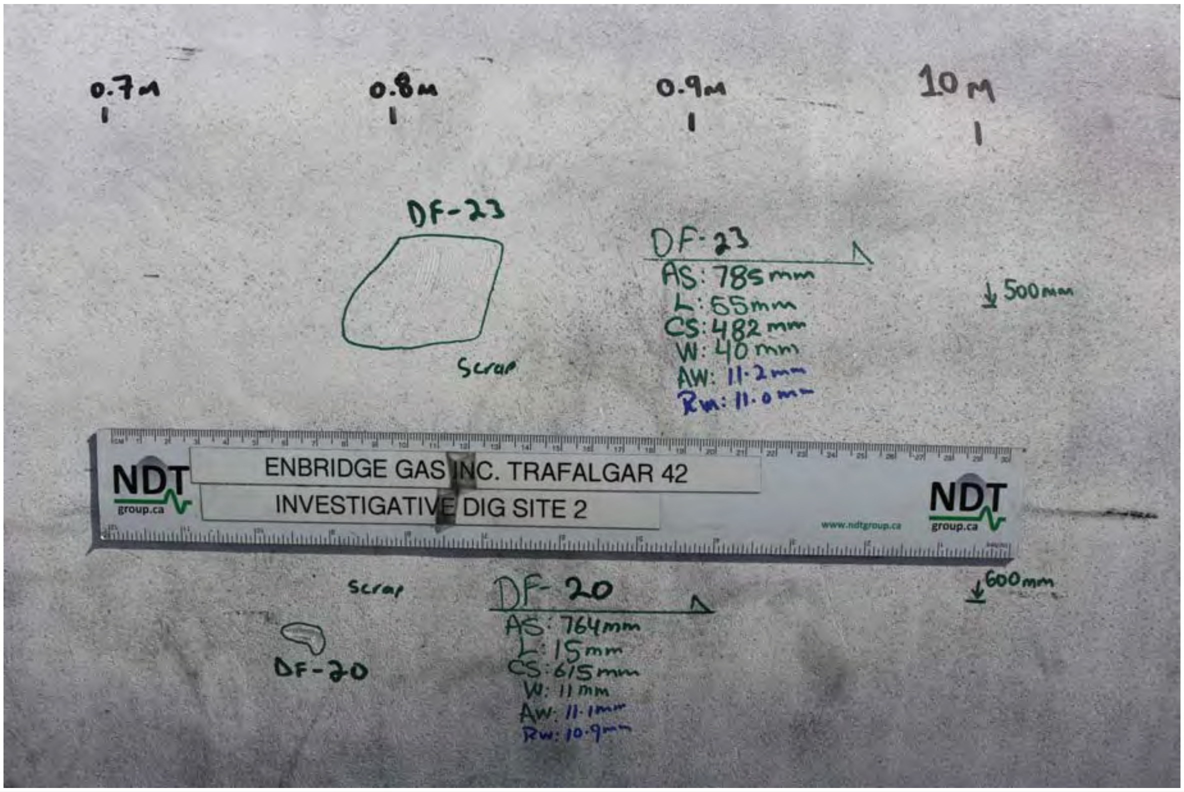


089 - DF-22

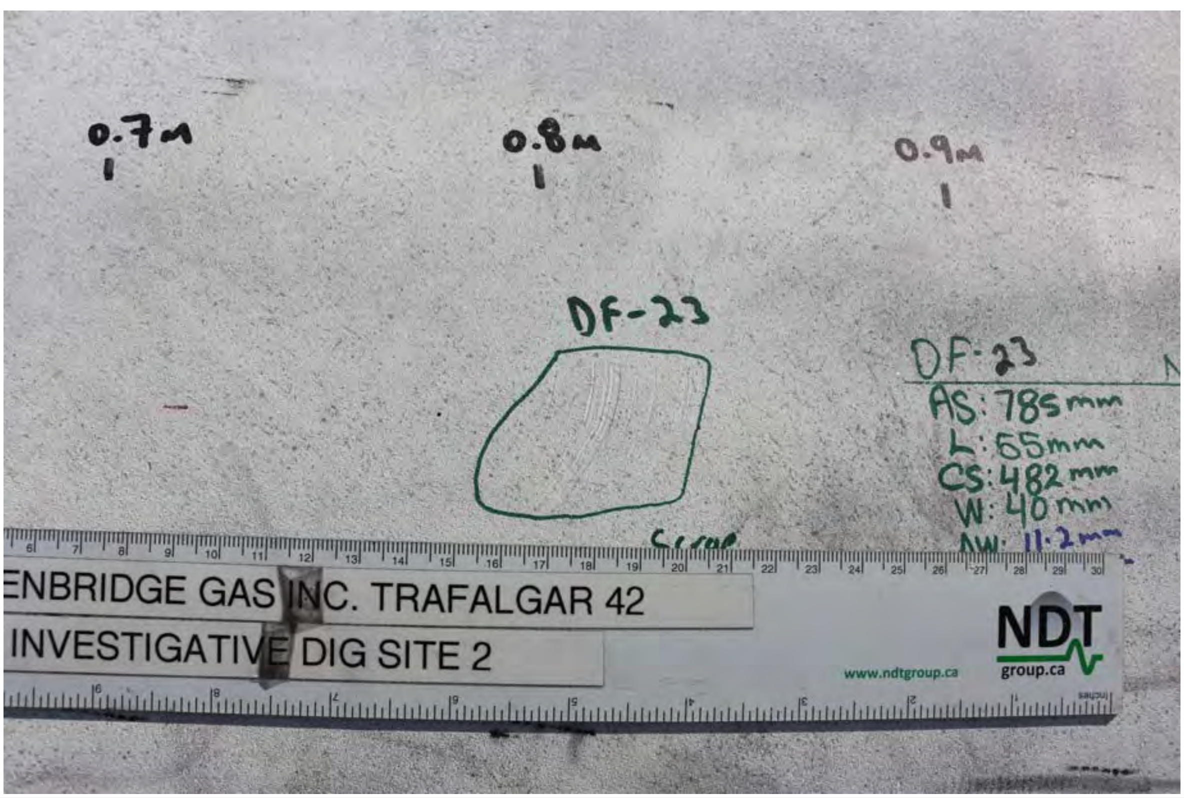


090 - DF-22 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42

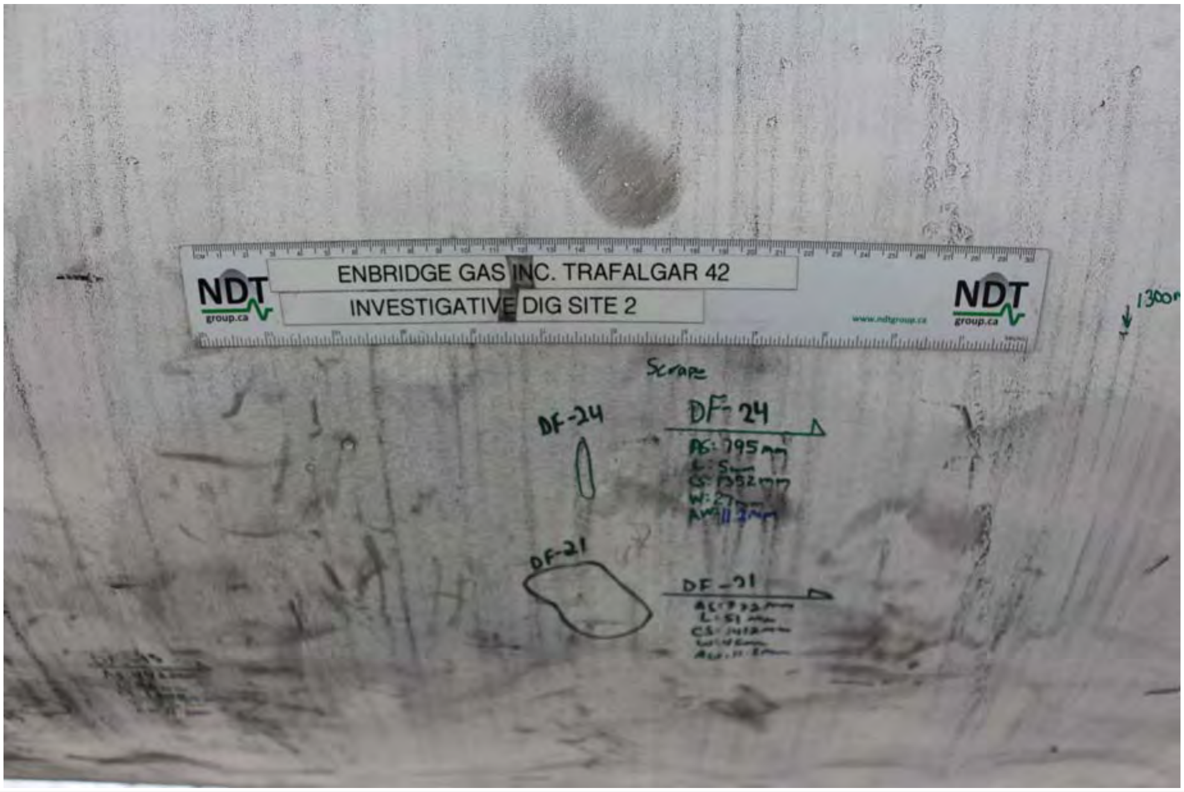


091 - DF-23

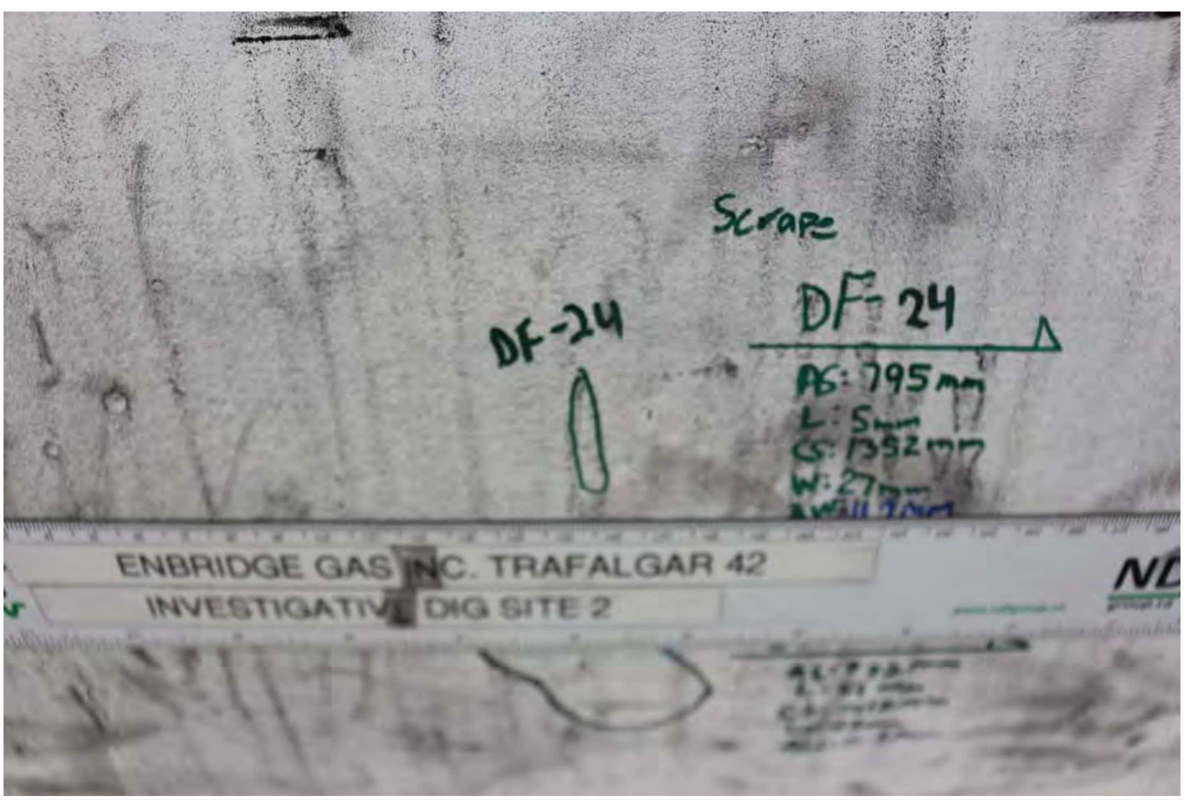


092 - DF-23 CLOSE UP

ENBRIDGE GAS INC. - TRAFALGAR NPS42



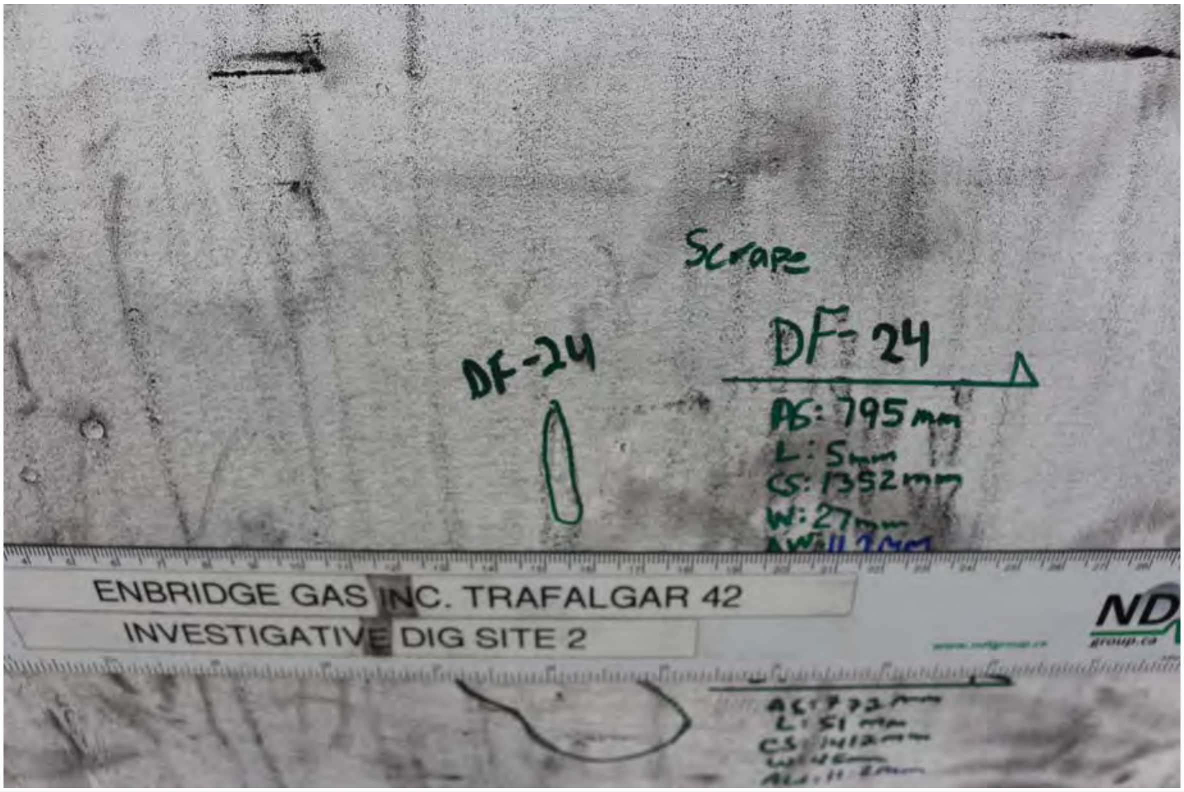
093 - DF-24



094 - DF-24 CLOSE UP

SITE 2 SCC INVESTIGATIVE DIG, SEP 04, 2019

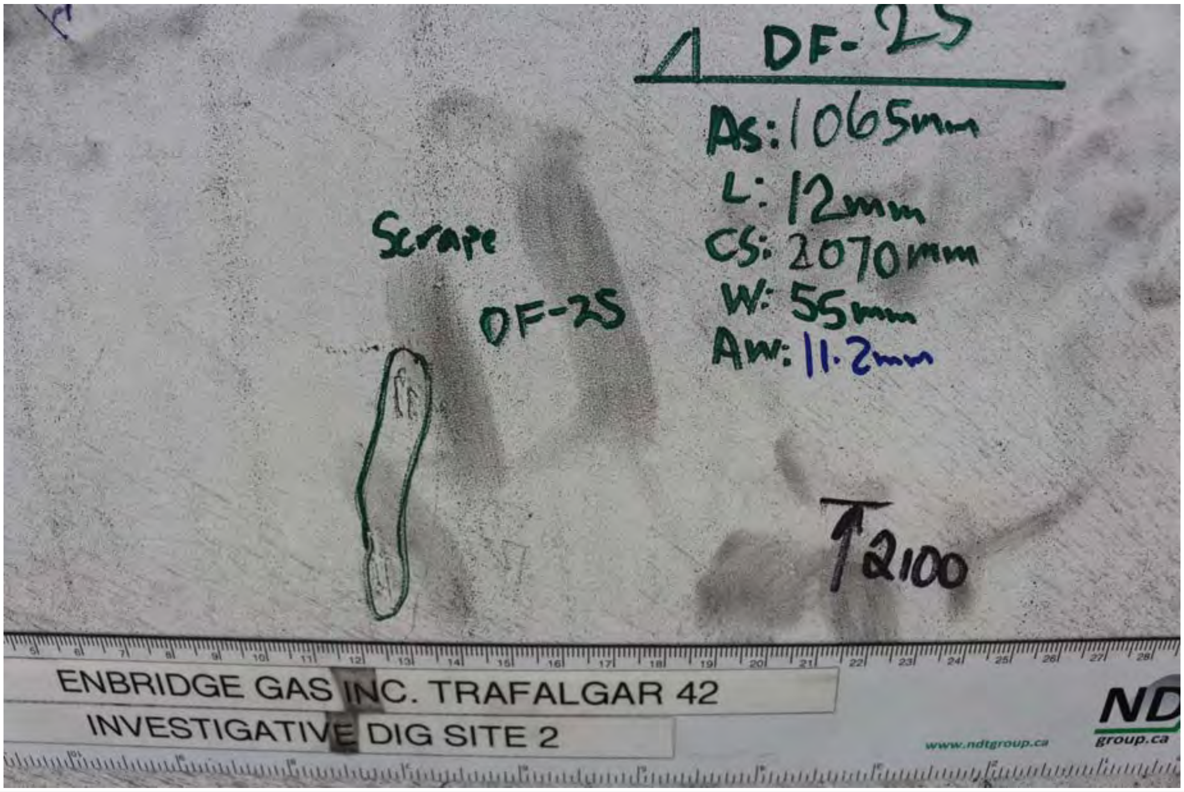
ENBRIDGE GAS INC. - TRAFALGAR NPS42



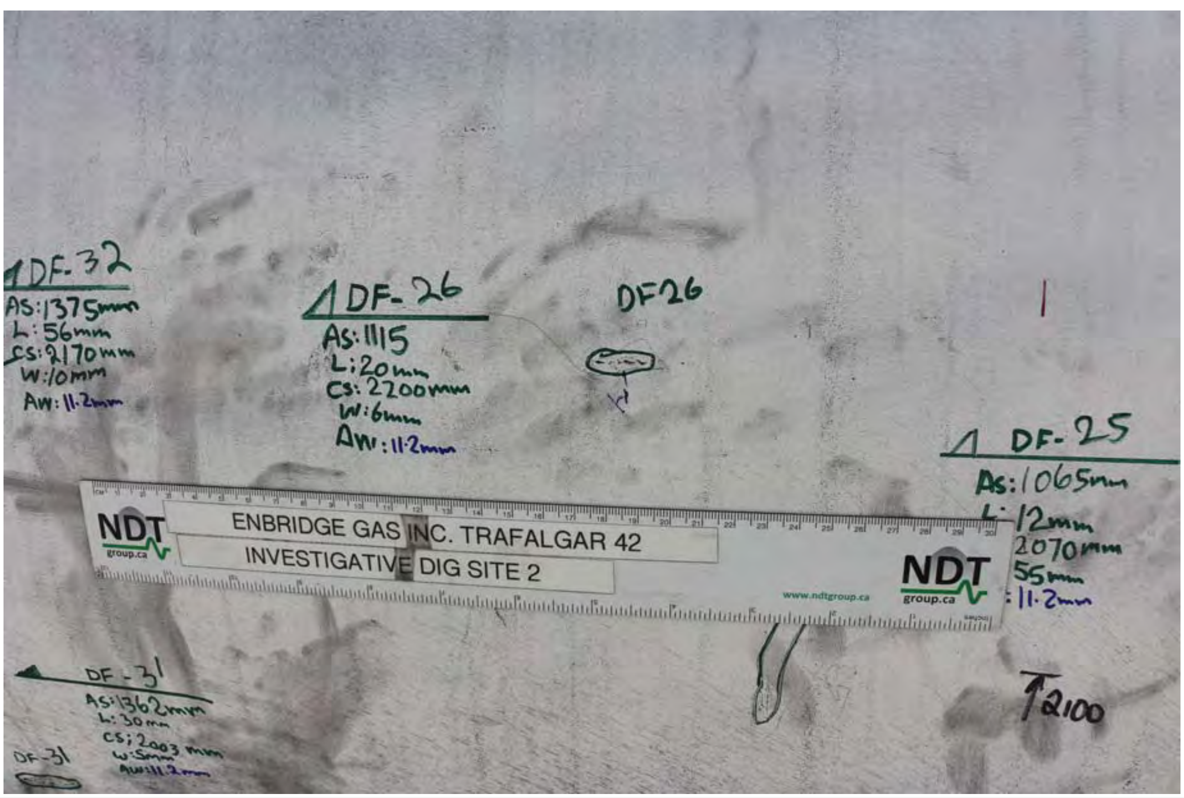
095 - DF-24 CLOSE UP (2)

096 - DF-25

ENBRIDGE GAS INC. - TRAFALGAR NPS42

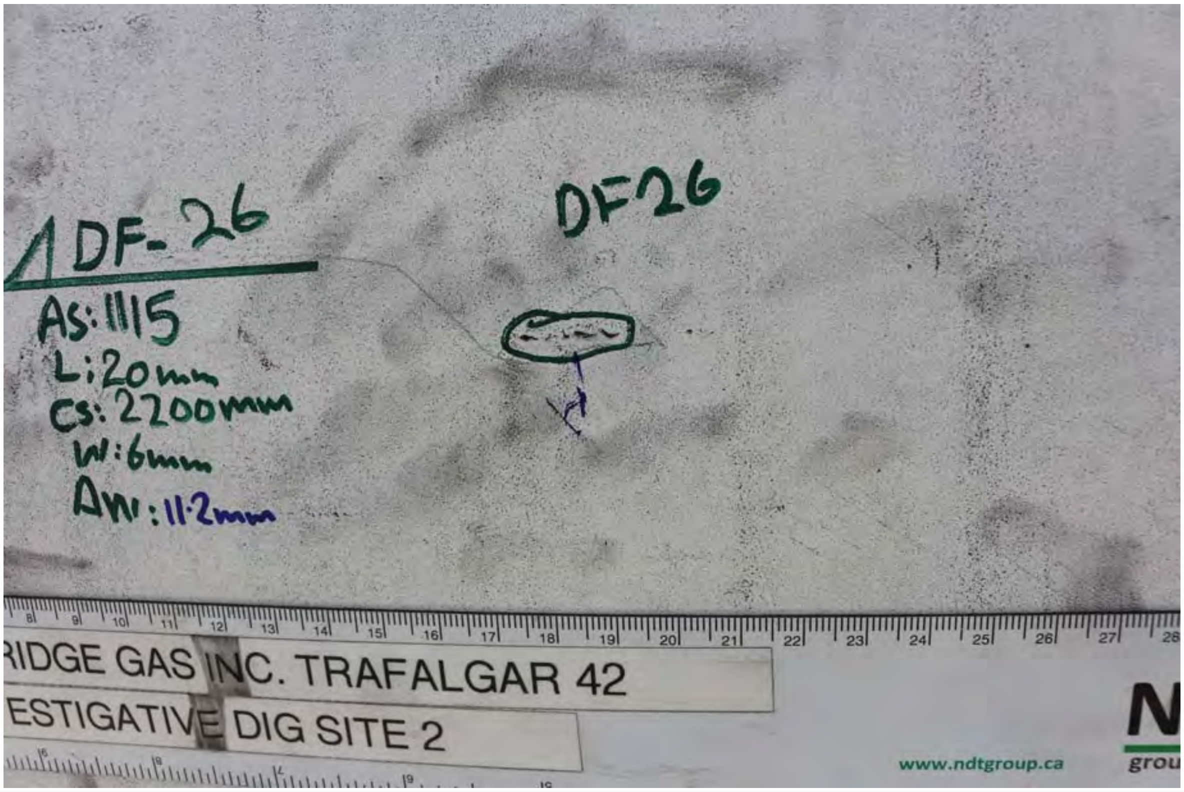


097 - DF-25 CLOSE UP

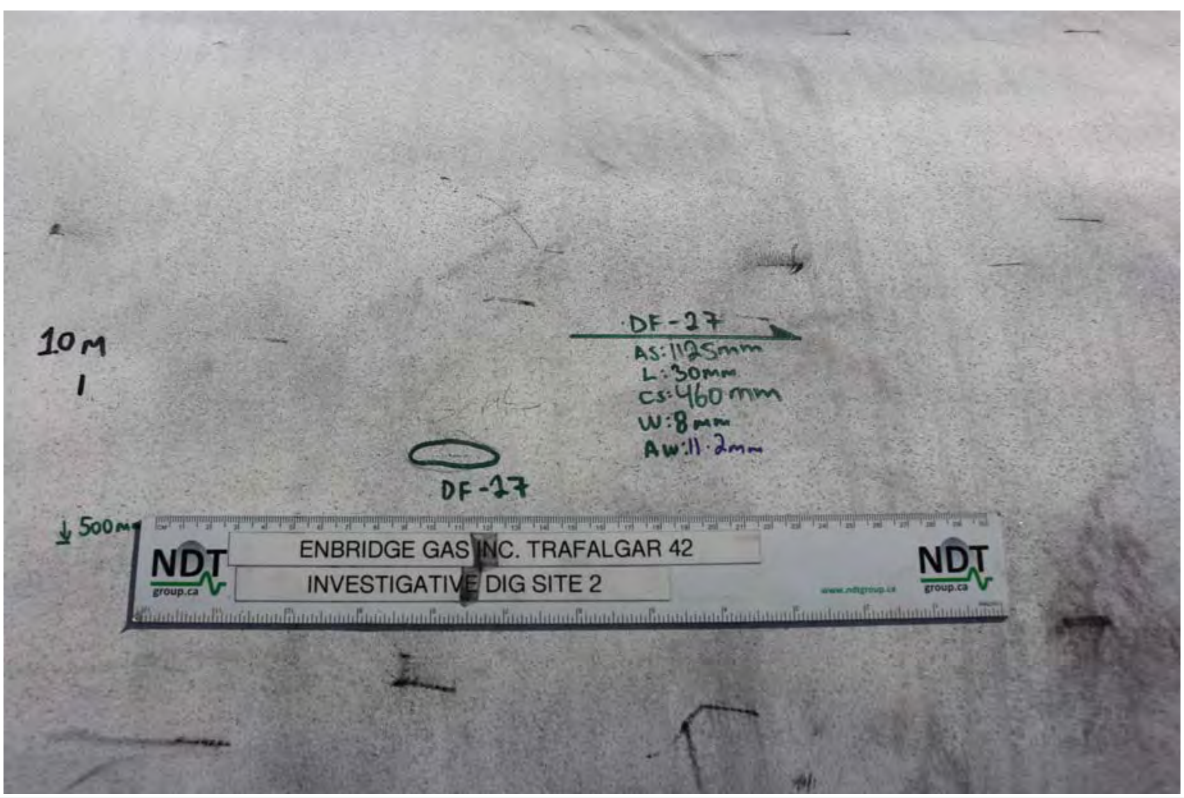


098 - DF-26

ENBRIDGE GAS INC. - TRAFALGAR NPS42

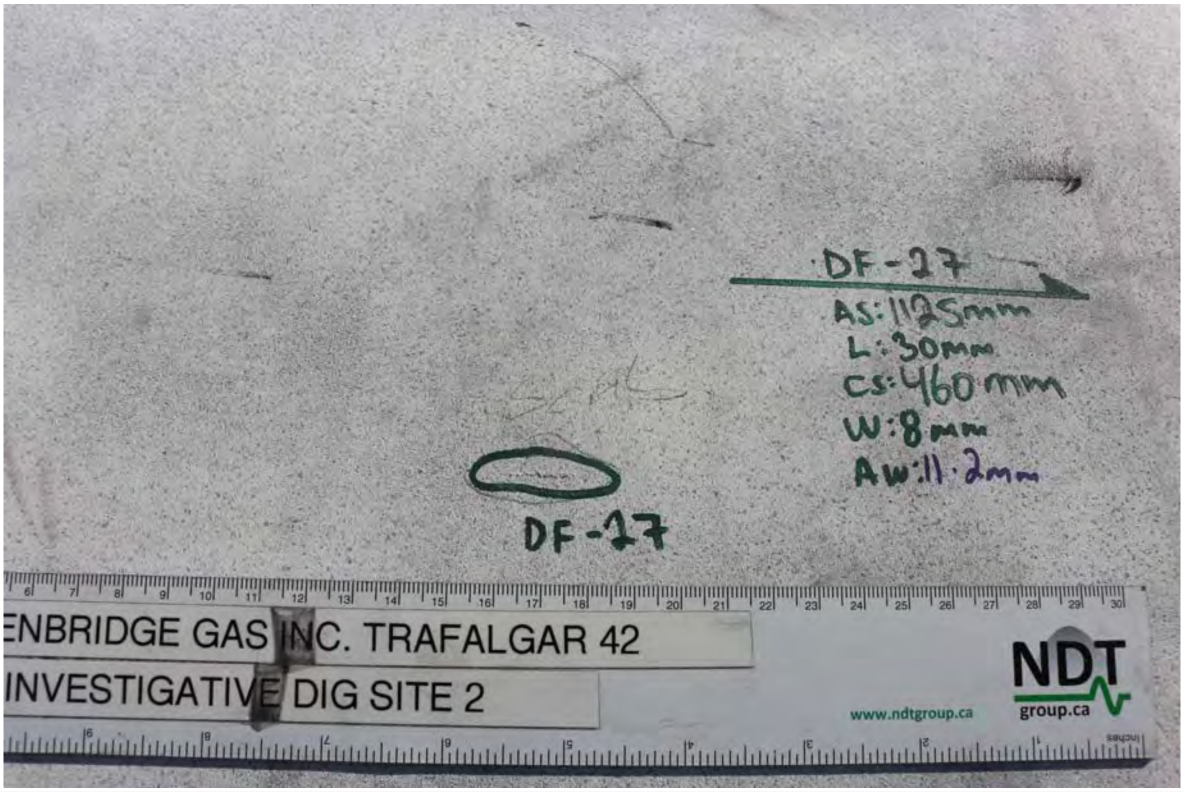


099 - DF-26 CLOSE UP

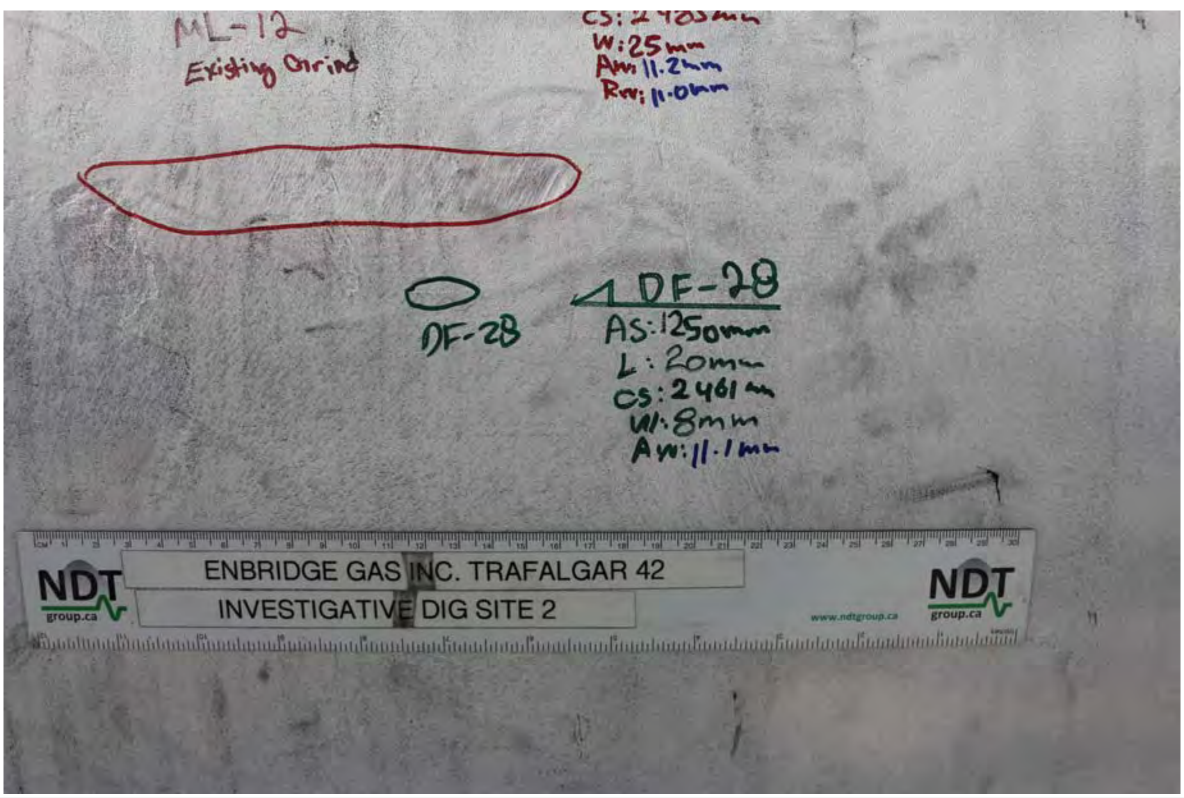


100 - DF-27

ENBRIDGE GAS INC. - TRAFALGAR NPS42

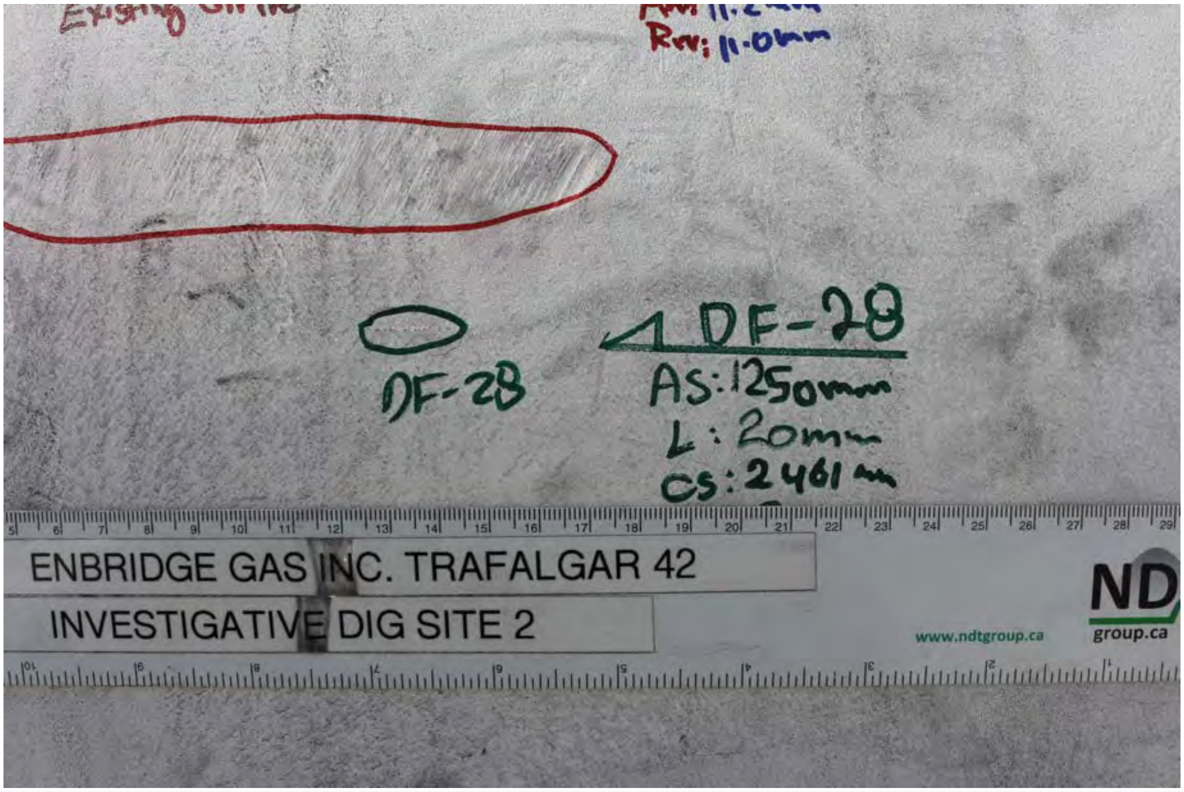


101 - DF-27 CLOSE UP

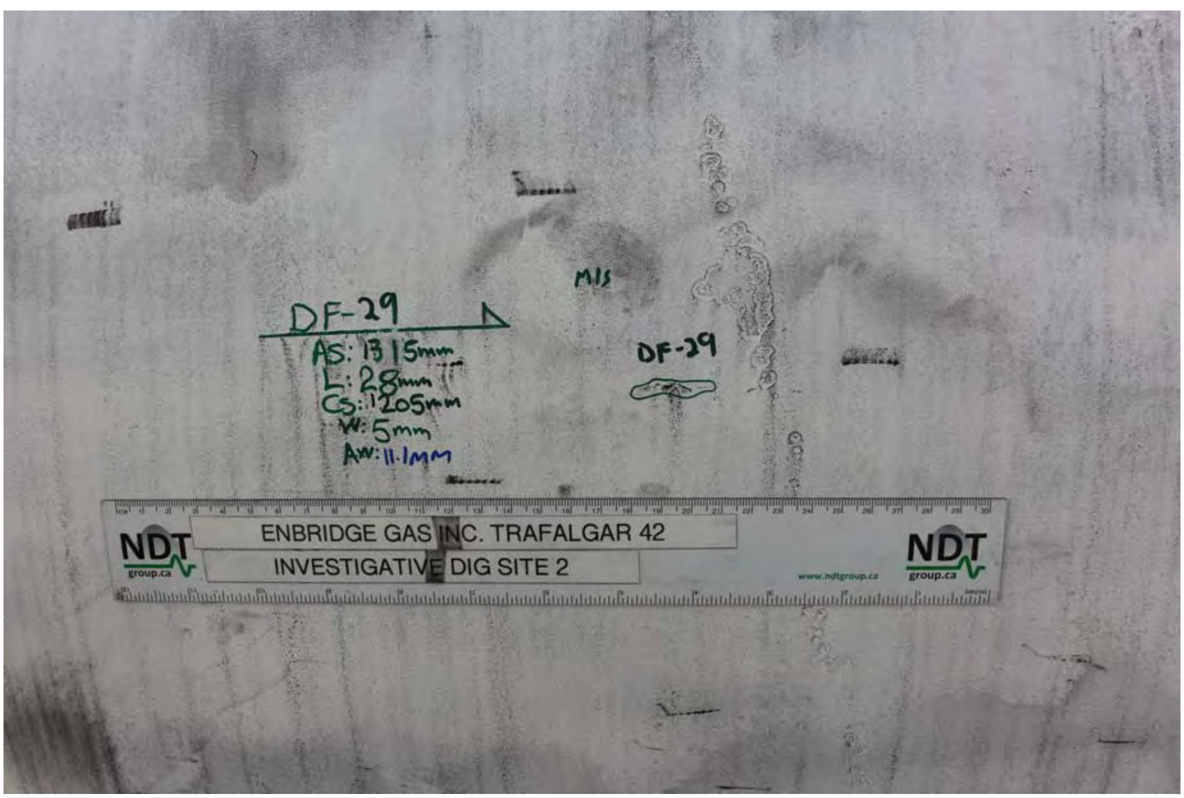


102 - DF-28

ENBRIDGE GAS INC. - TRAFALGAR NPS42

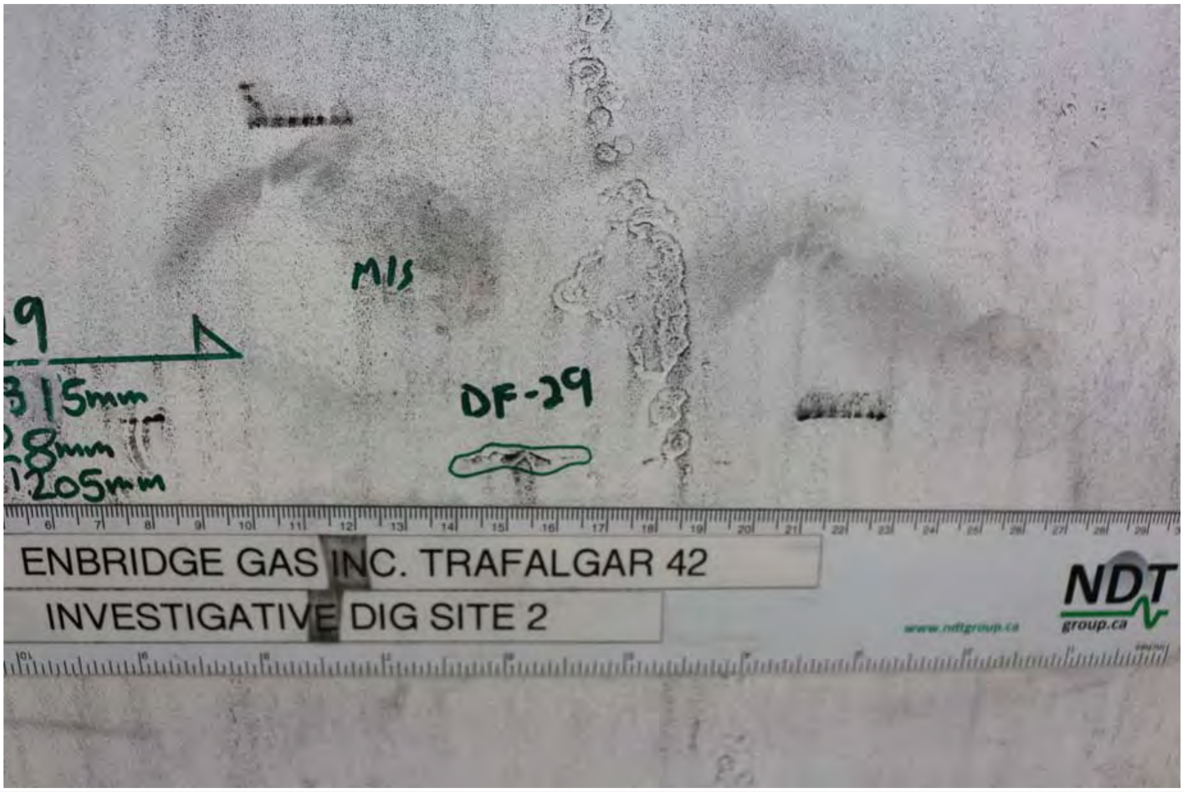


103 - DF-28 CLOSE UP

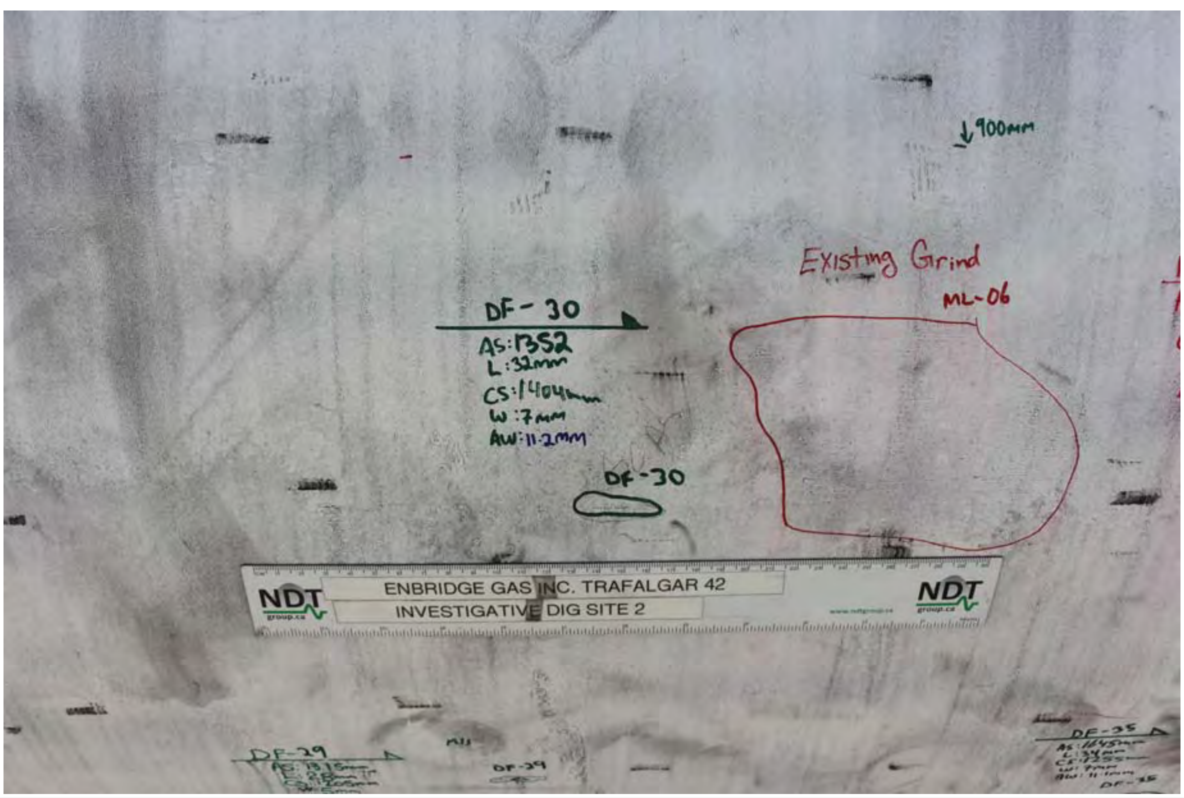


104 - DF-29

ENBRIDGE GAS INC. - TRAFALGAR NPS42

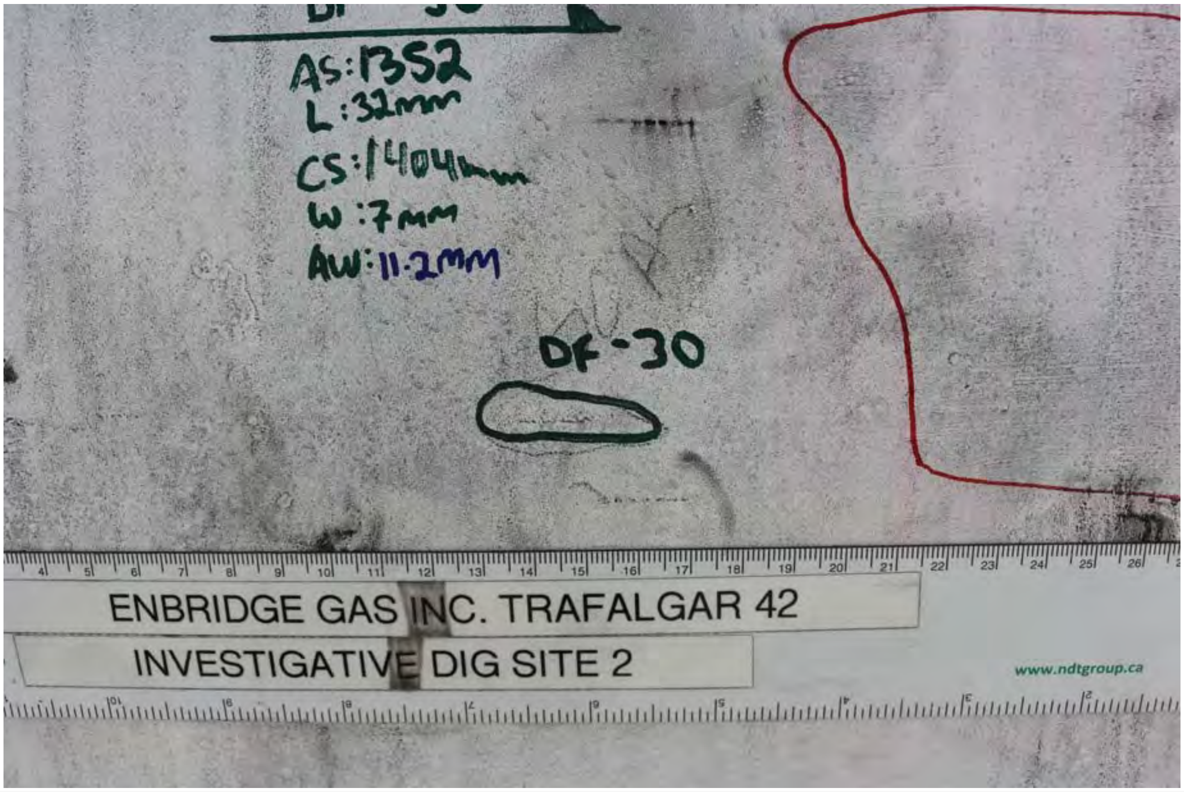


105 - DF-29 CLOSE UP

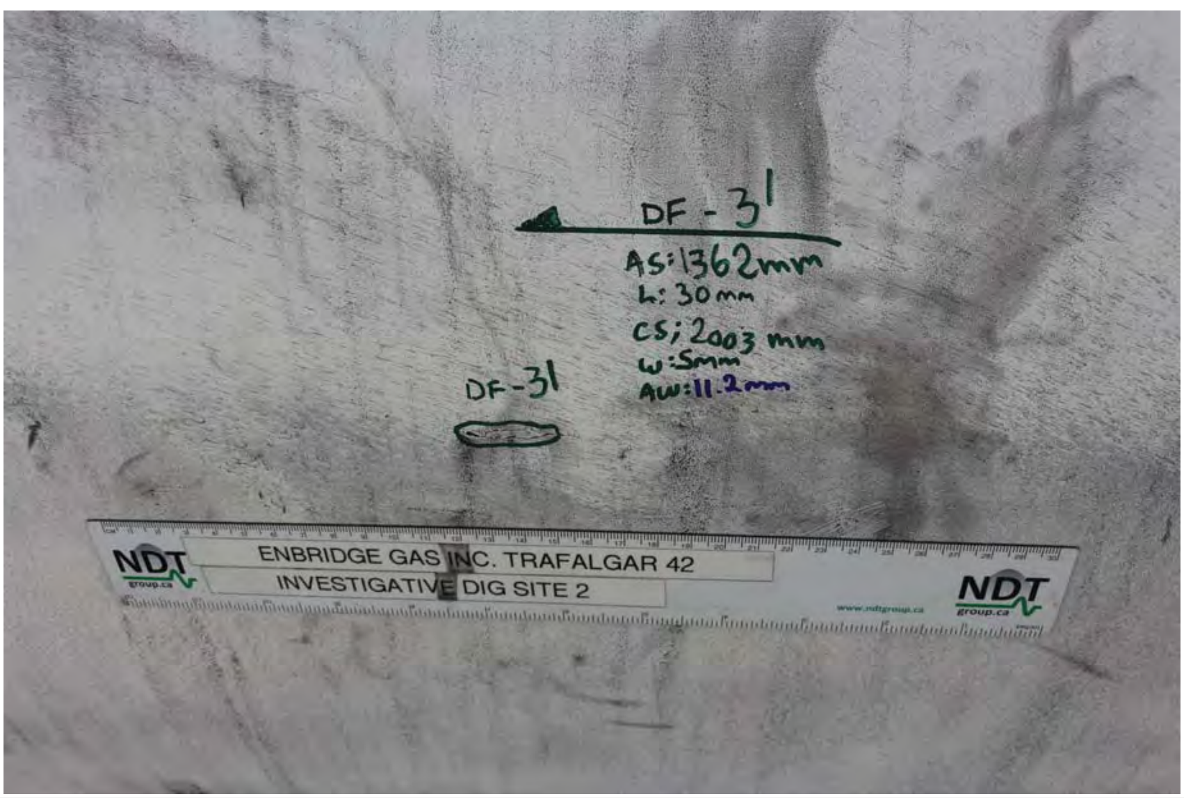


106 - DF-30

ENBRIDGE GAS INC. - TRAFALGAR NPS42

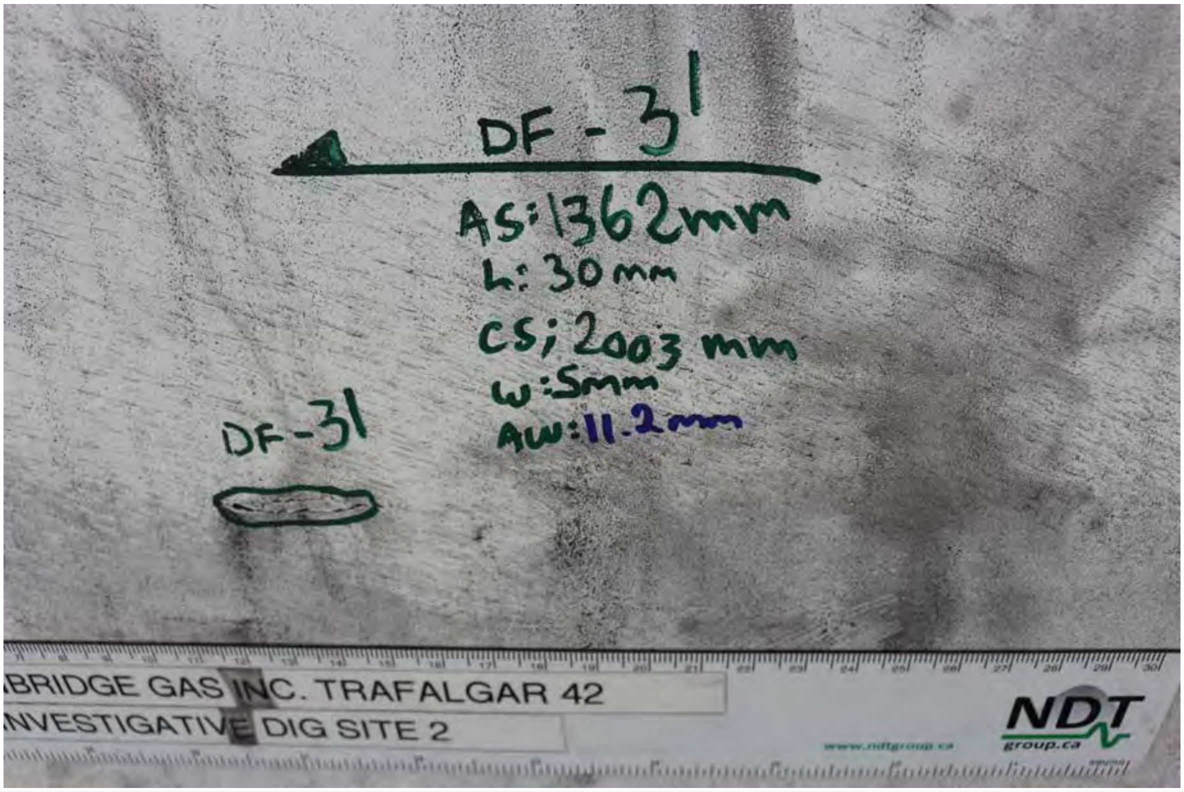


107 - DF-30 CLOSE UP

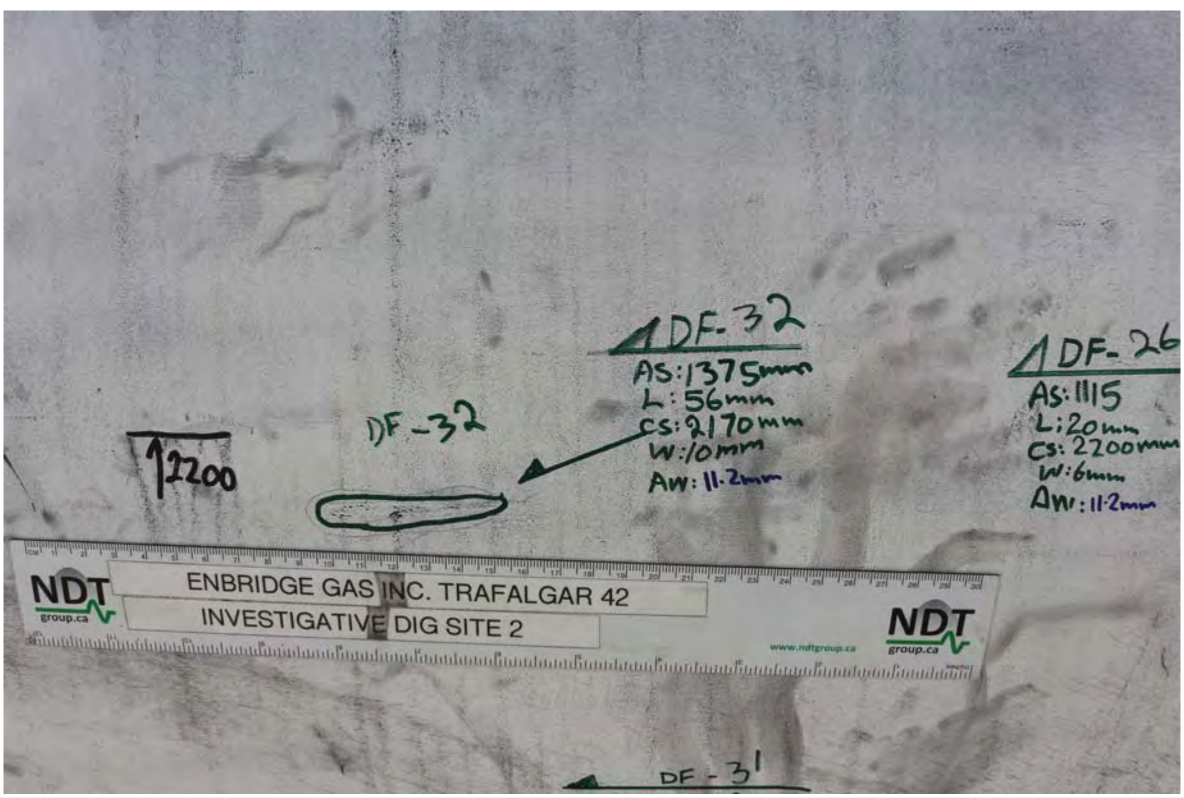


108 - DF-31

ENBRIDGE GAS INC. - TRAFALGAR NPS42

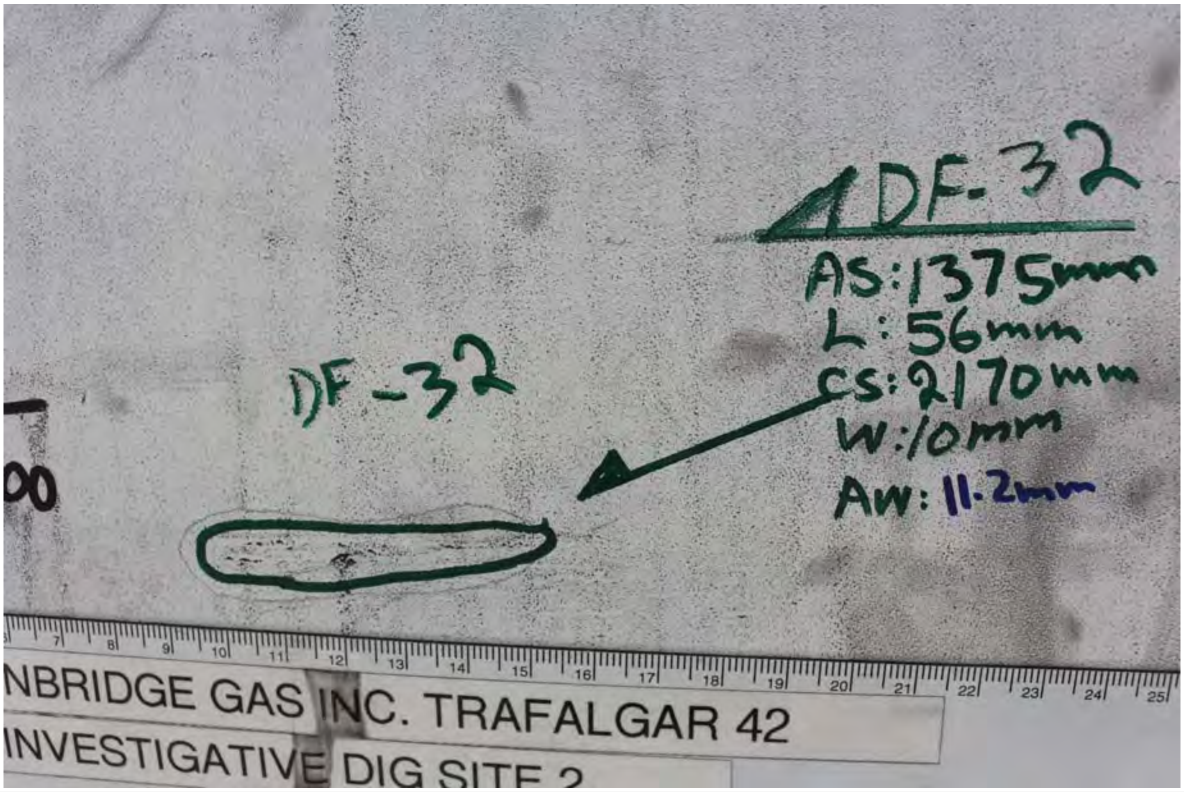


109 - DF-31 CLOSE UP

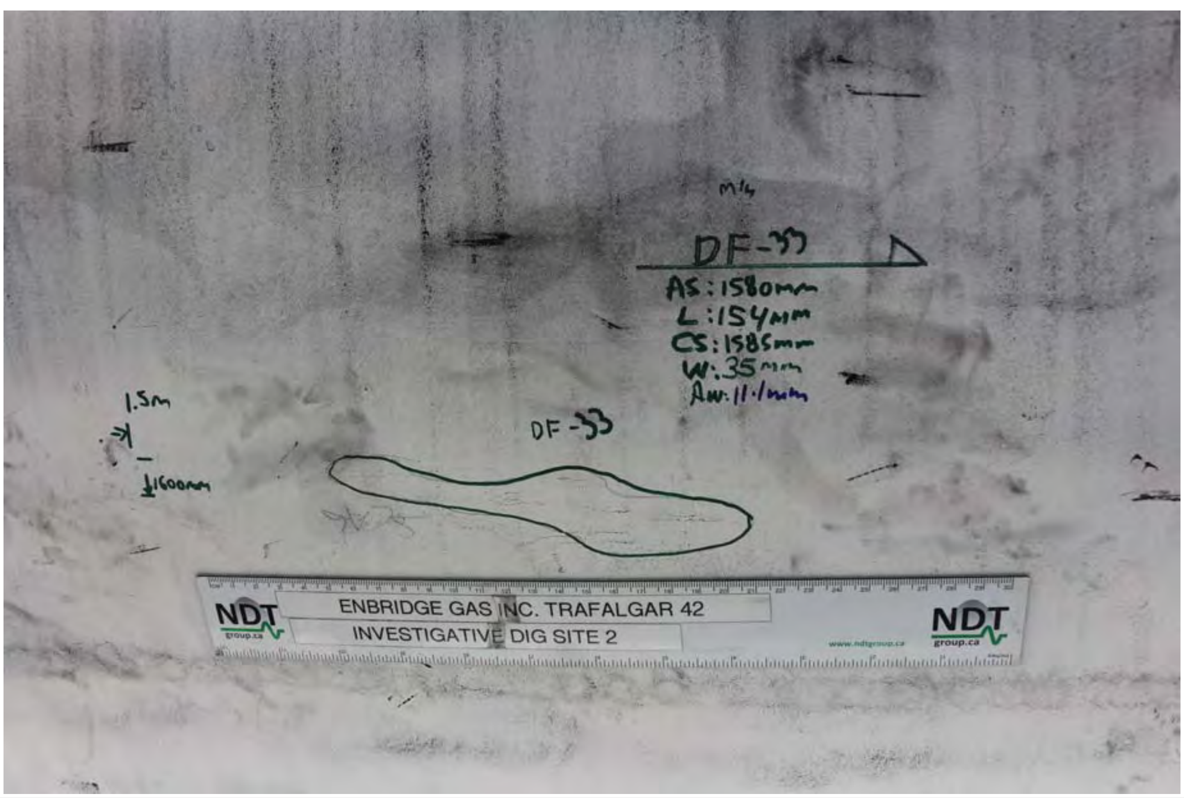


110 - DF-32

ENBRIDGE GAS INC. - TRAFALGAR NPS42

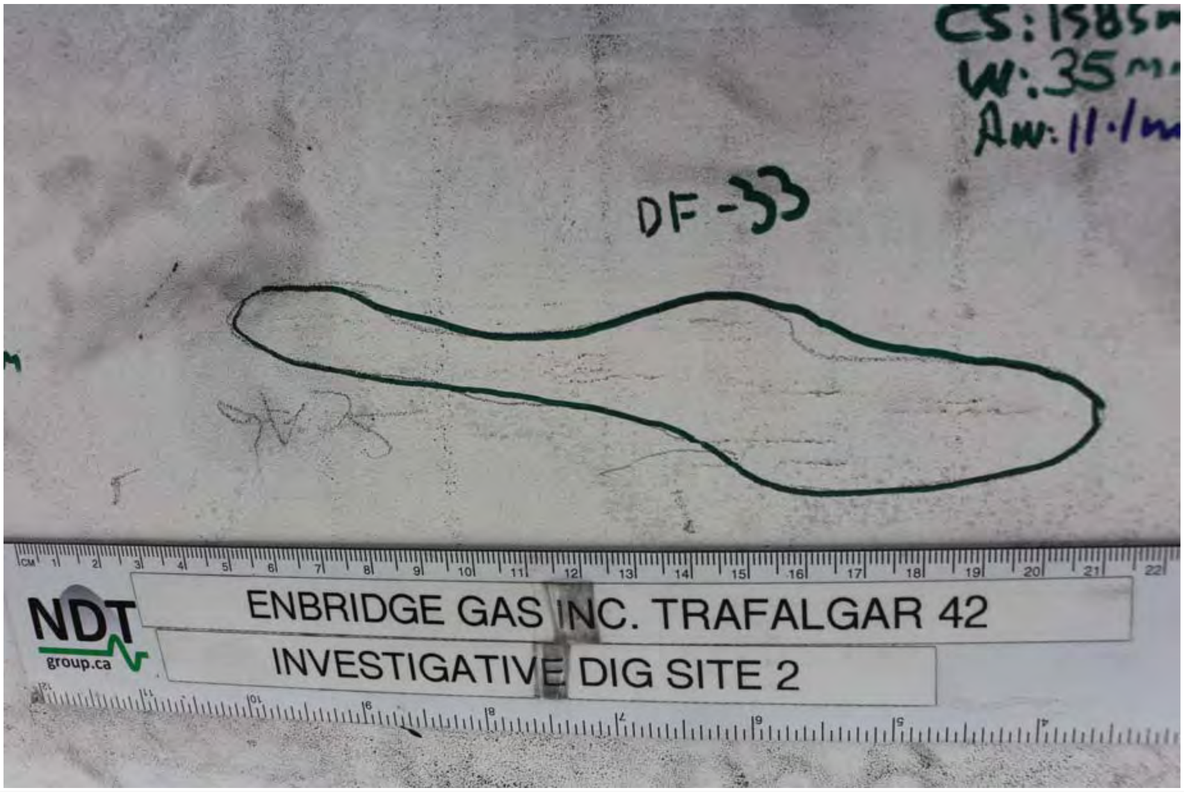


111 - DF-32 CLOSE UP

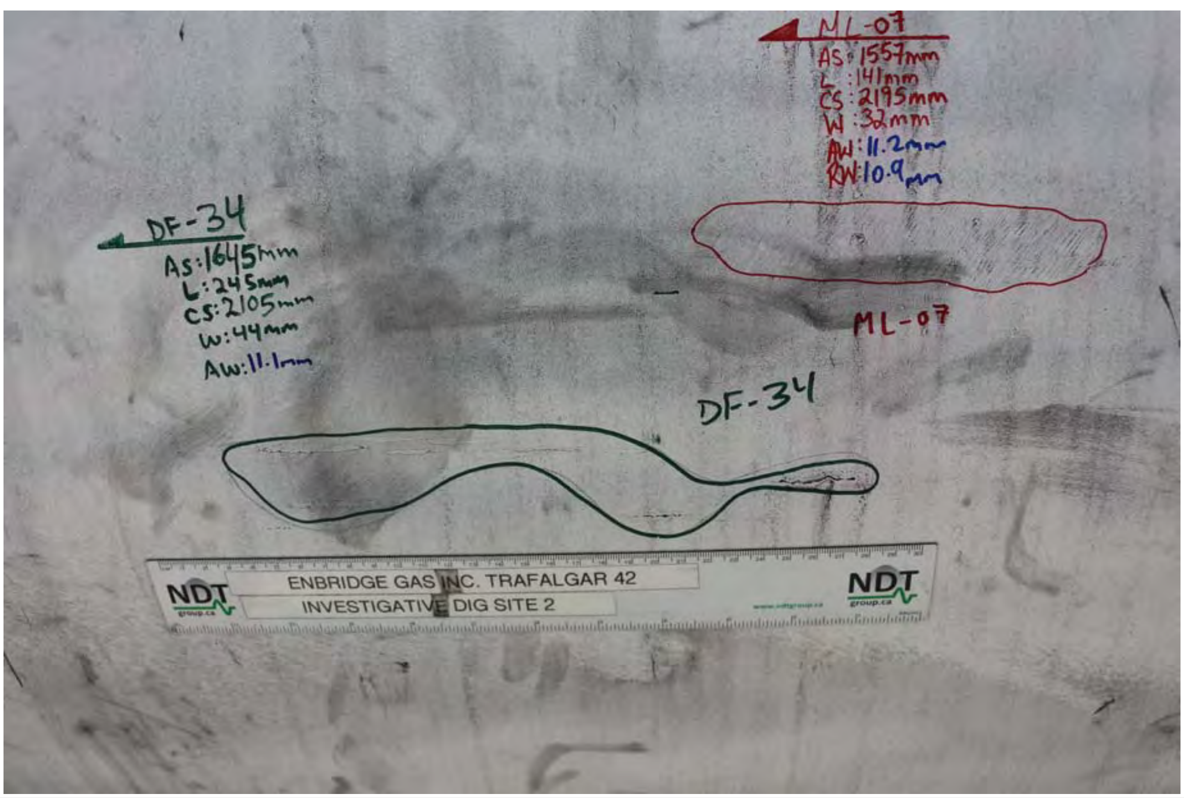


112 - DF-33

ENBRIDGE GAS INC. - TRAFALGAR NPS42

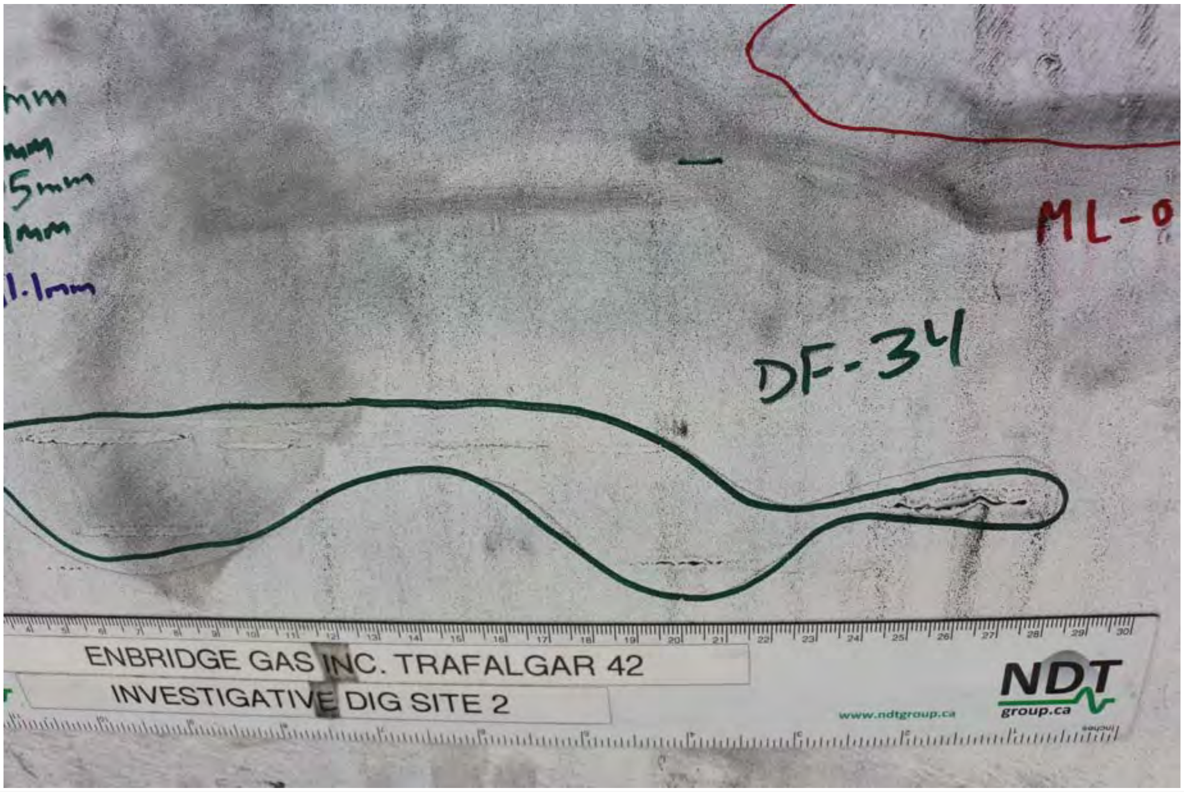


113 - DF-33 CLOSE UP

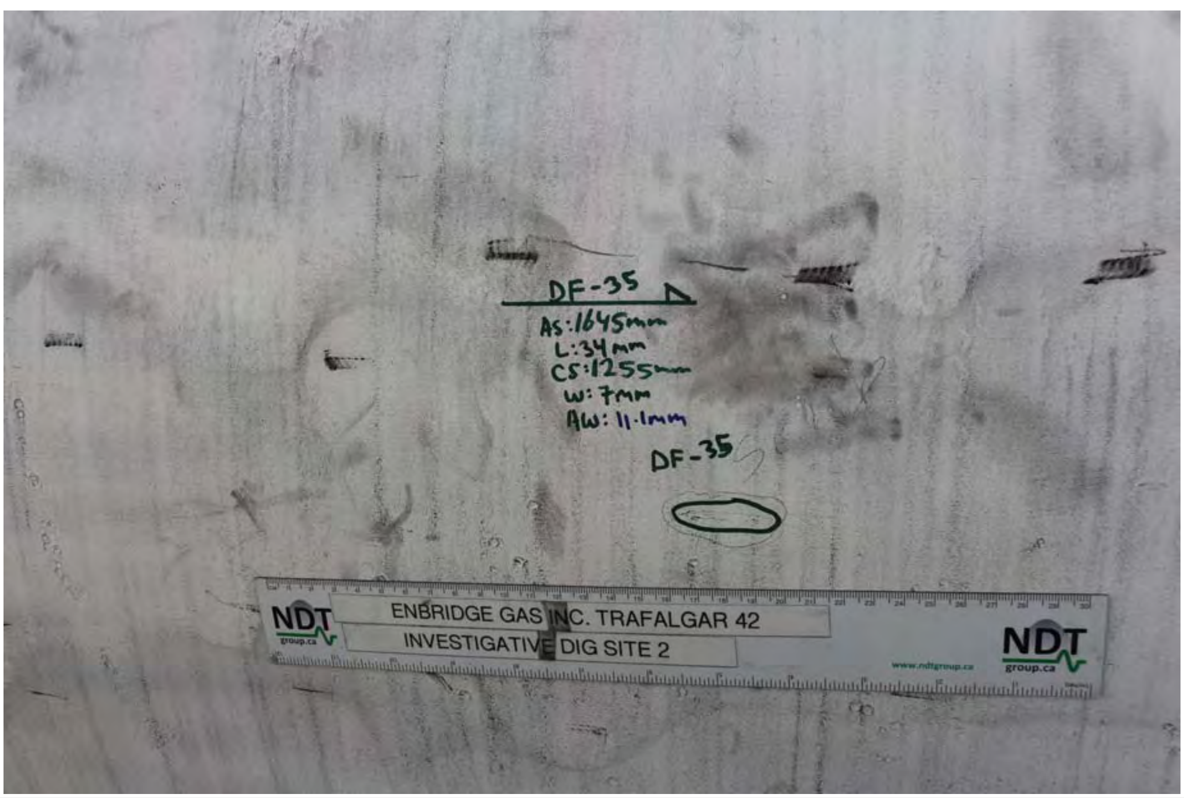


114 - DF-34

ENBRIDGE GAS INC. - TRAFALGAR NPS42

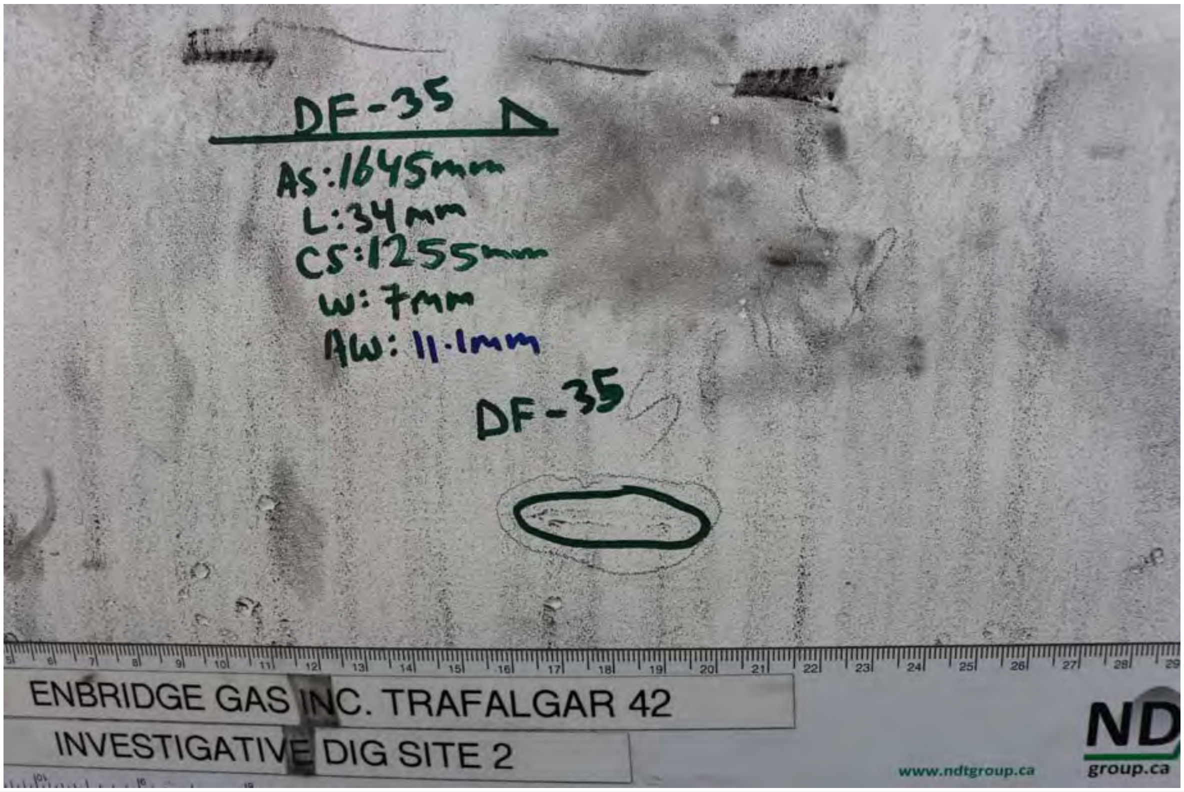


115 - DF-34 CLOSE UP

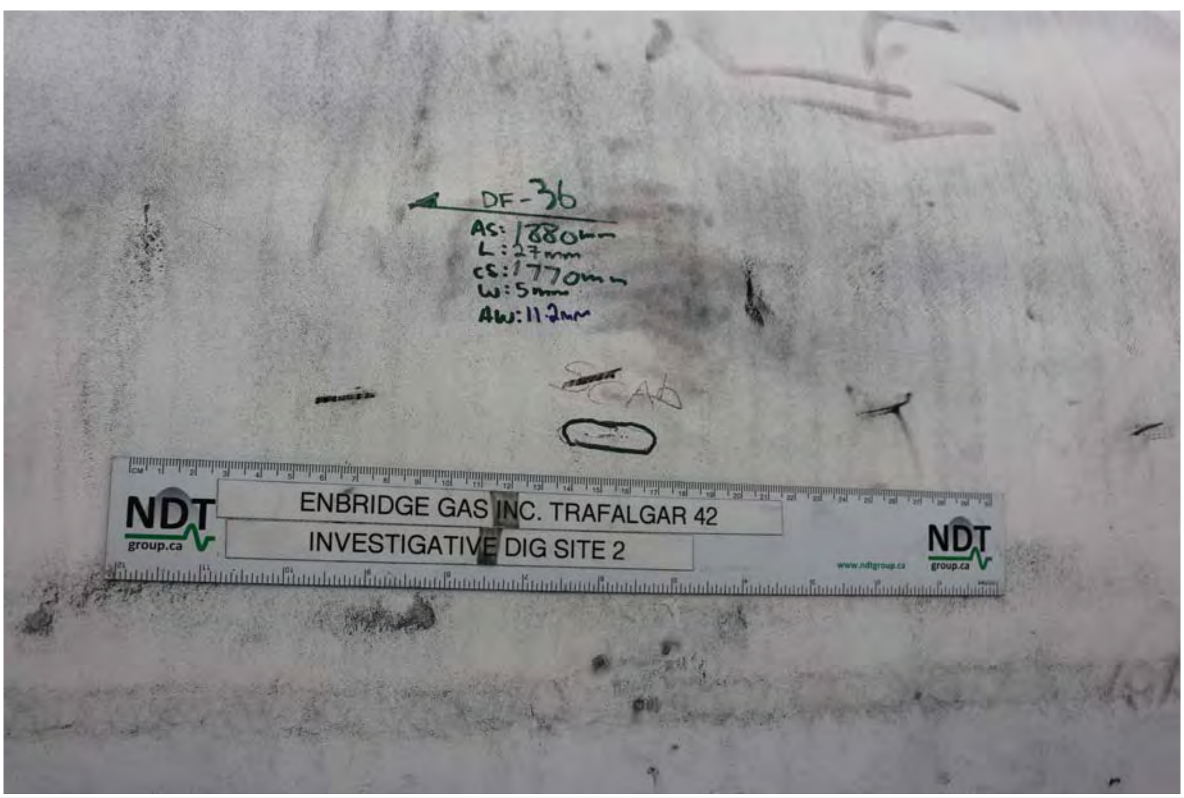


116 - DF-35

ENBRIDGE GAS INC. - TRAFALGAR NPS42

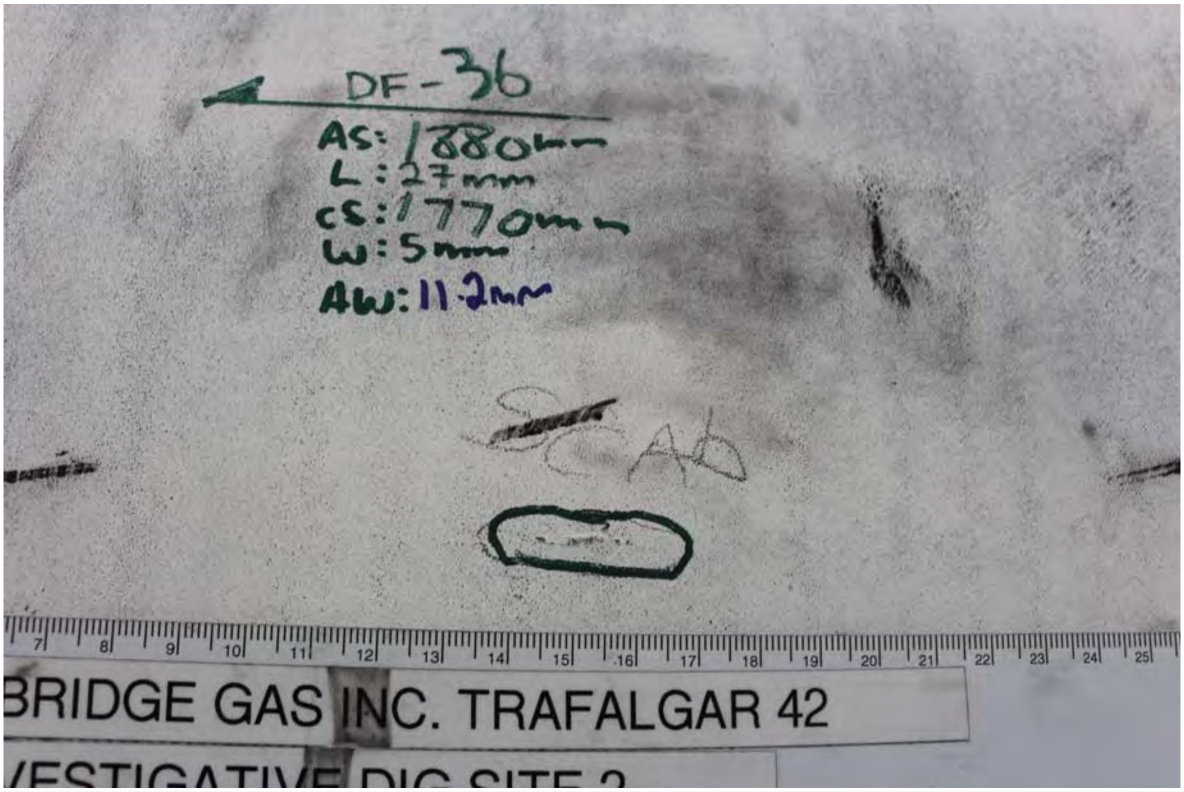


117 - DF-35 CLOSE UP

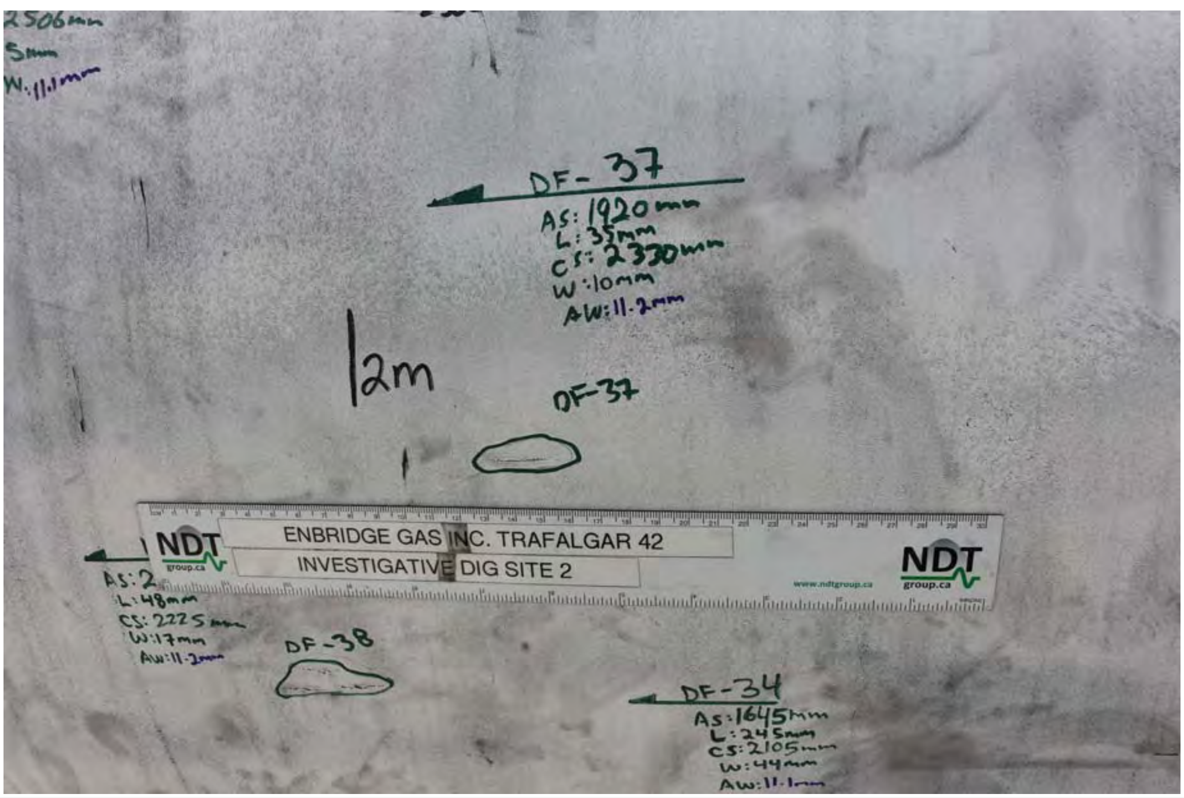


118 - DF-36

ENBRIDGE GAS INC. - TRAFALGAR NPS42

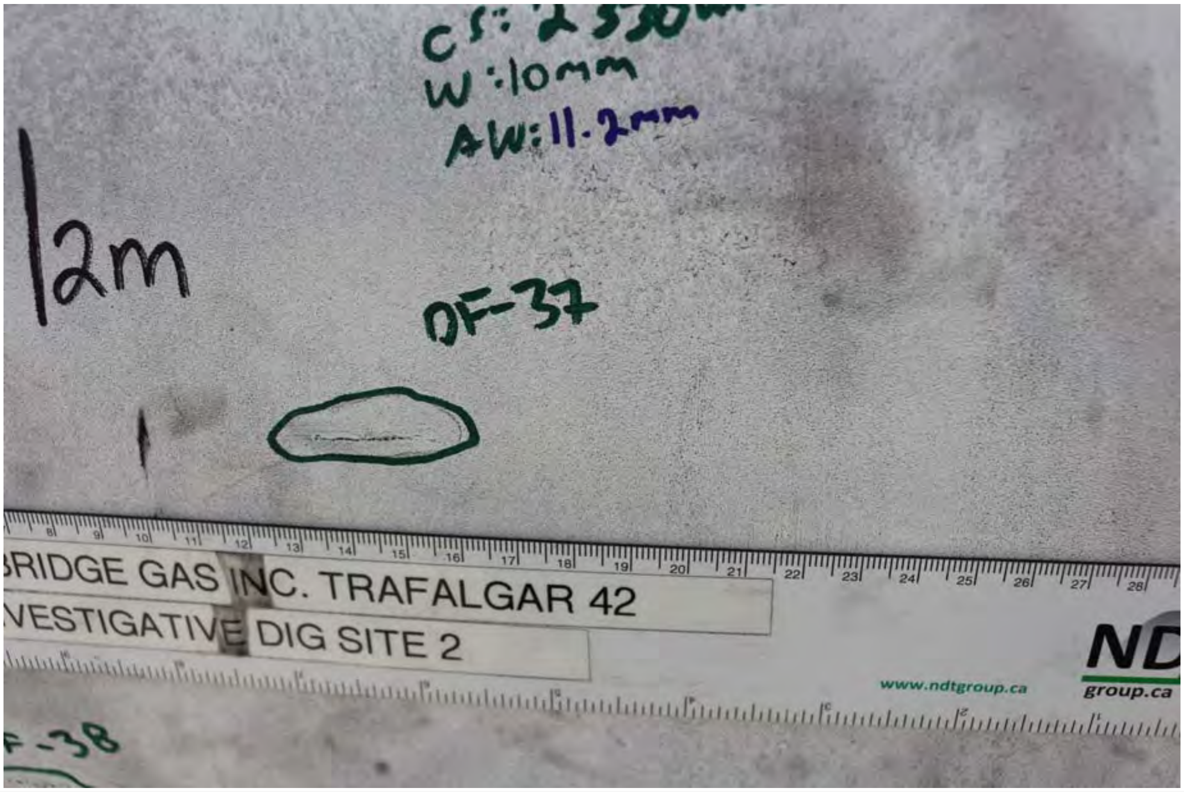


119 - DF-36 CLOSE UP

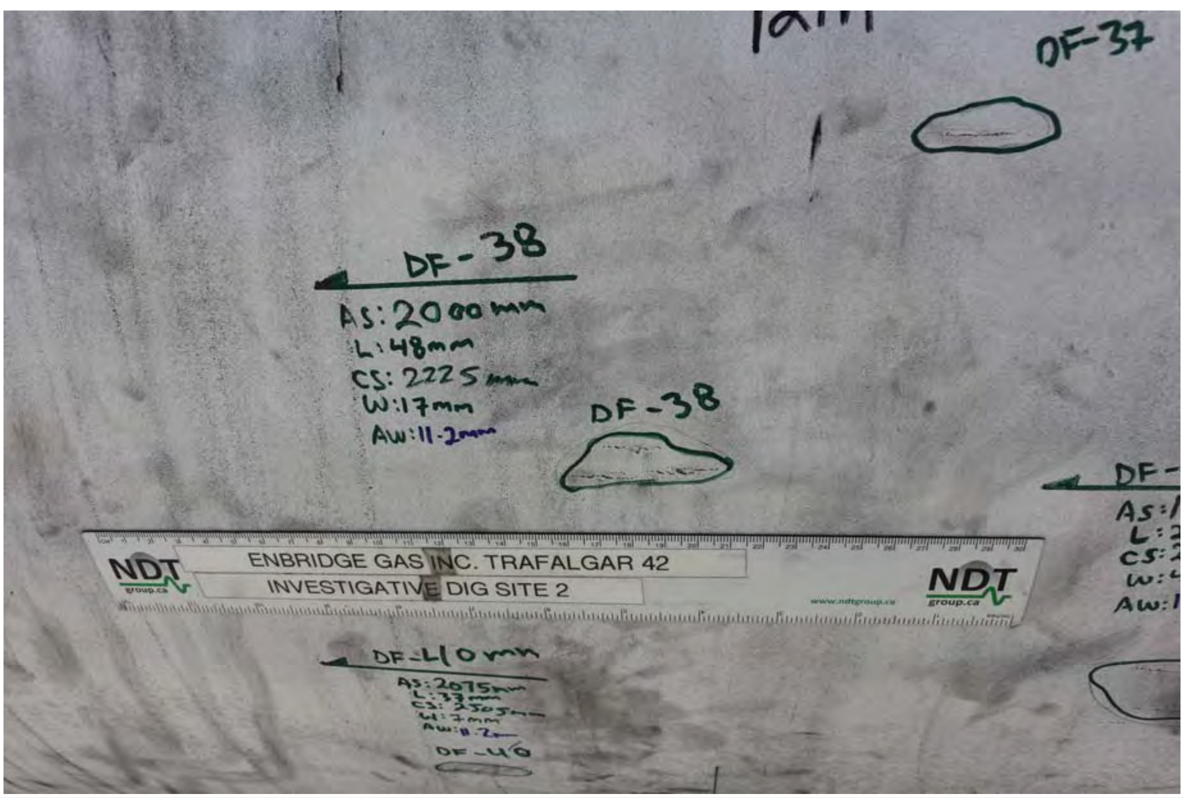


120 - DF-37

ENBRIDGE GAS INC. - TRAFALGAR NPS42

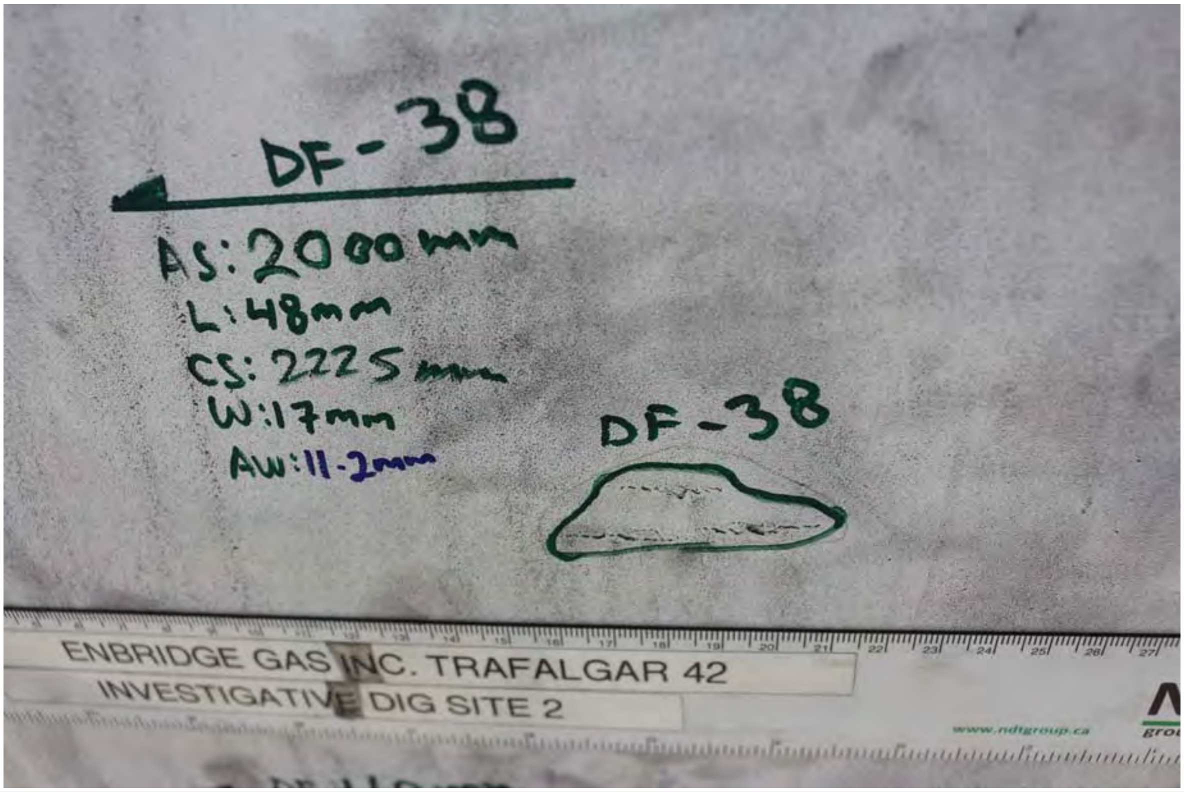


121 - DF-37 CLOSE UP

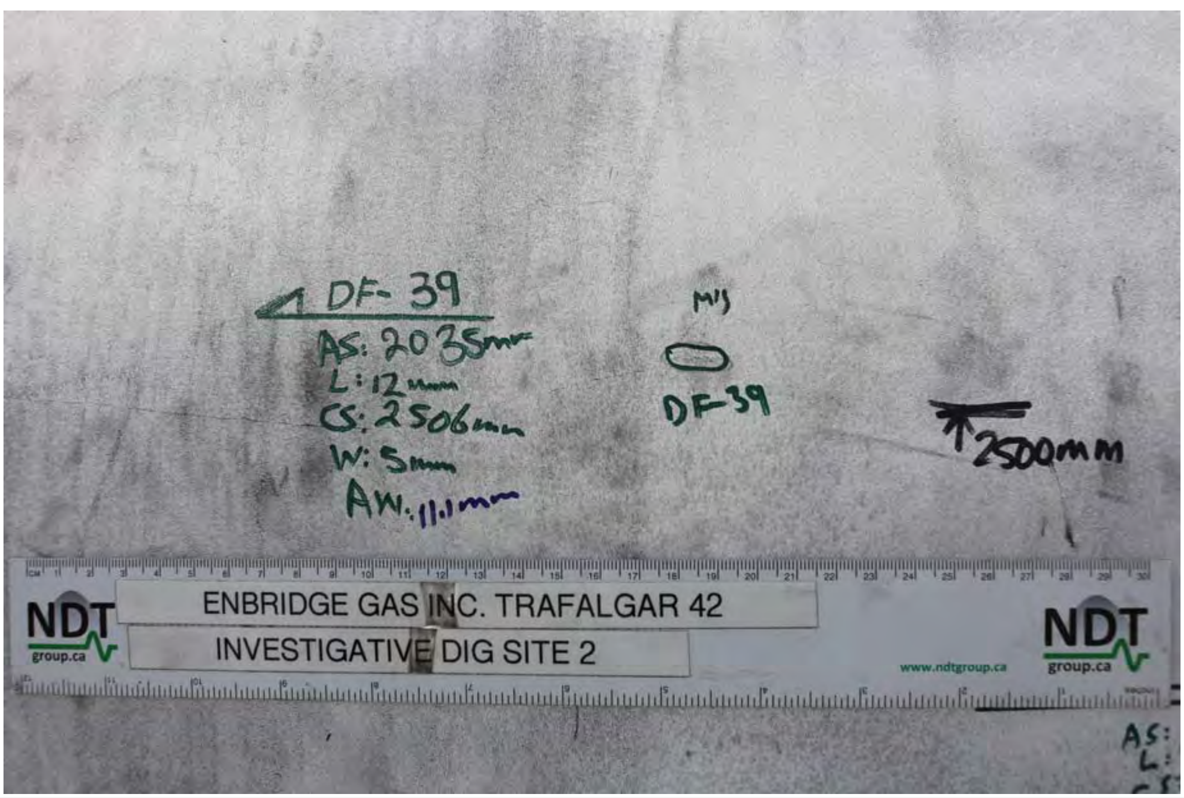


122 - DF-38

ENBRIDGE GAS INC. - TRAFALGAR NPS42

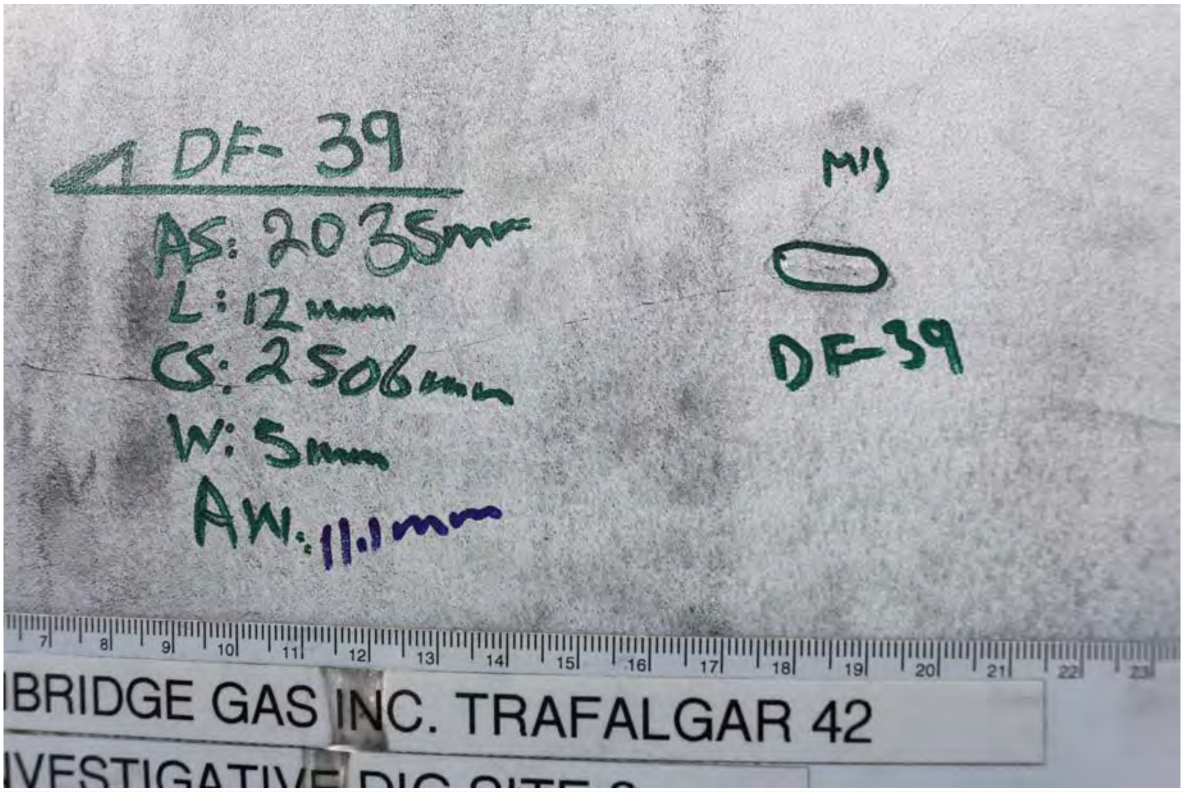


123 - DF-38 CLOSE UP

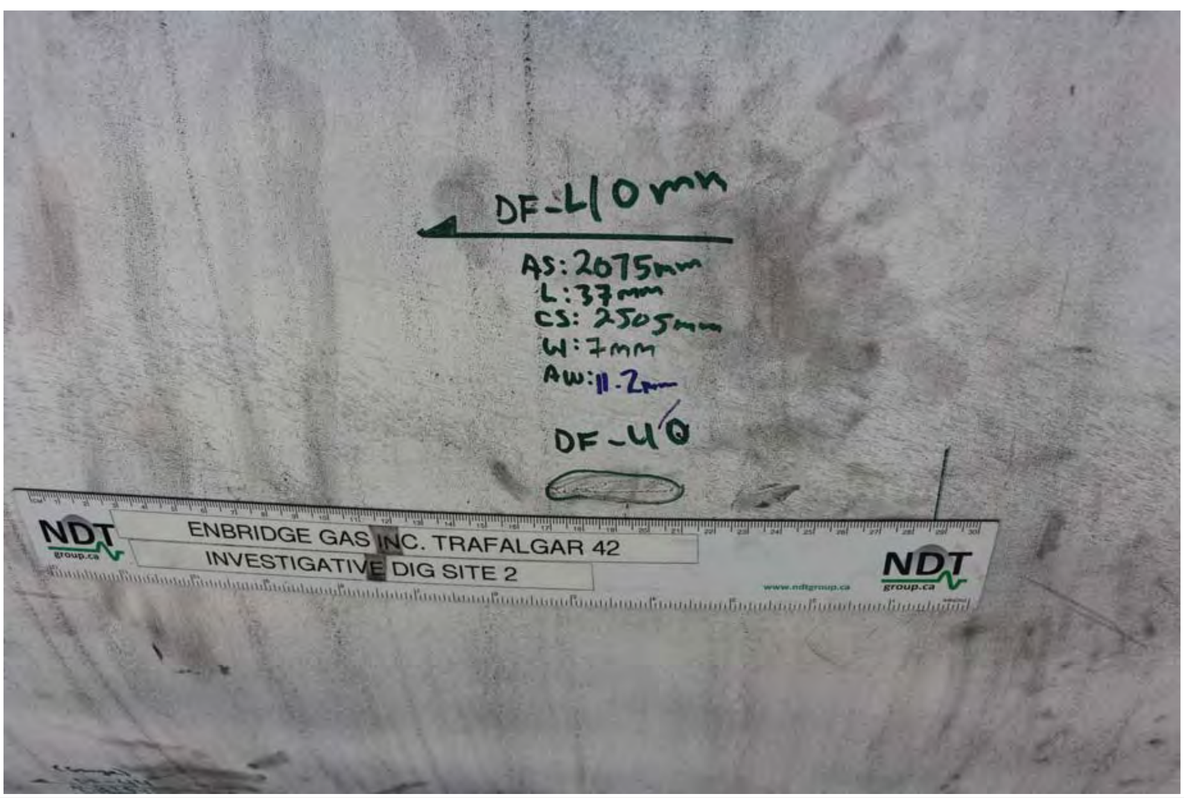


124 - DF-39

ENBRIDGE GAS INC. - TRAFALGAR NPS42

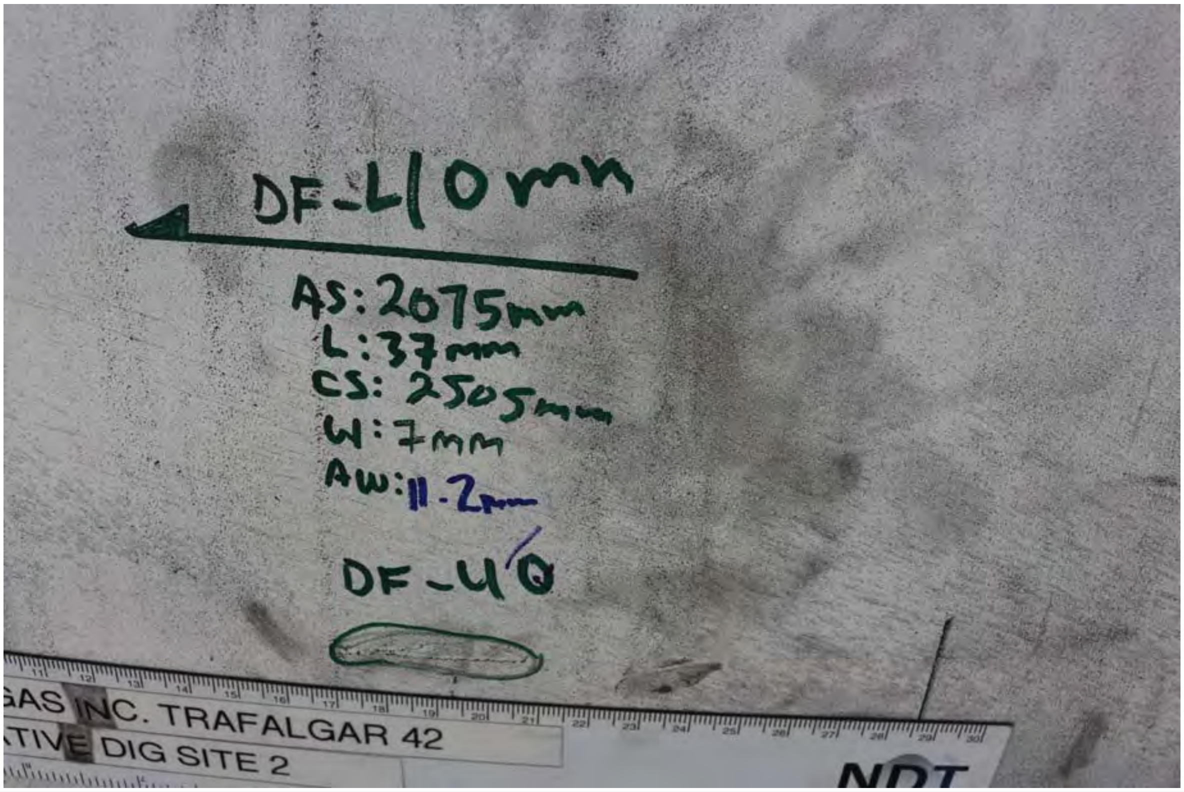


125 - DF-39 CLOSE UP

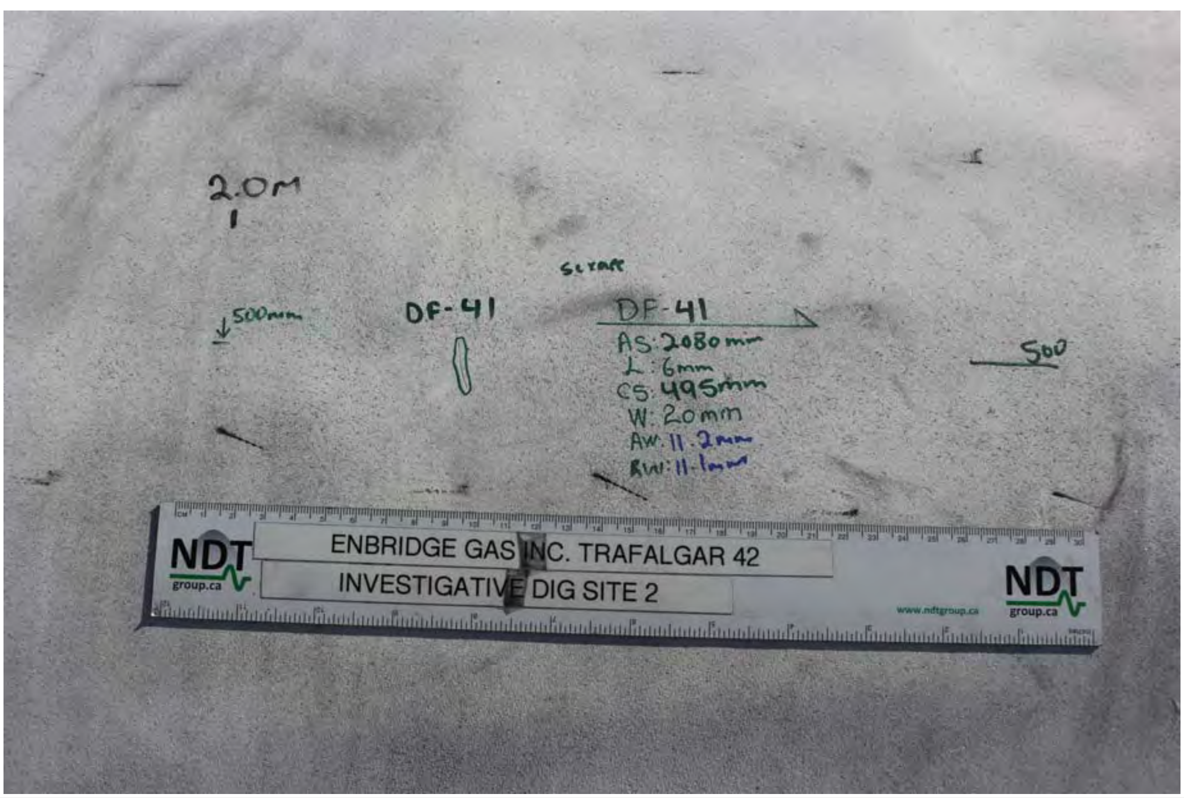


126 - DF-40

ENBRIDGE GAS INC. - TRAFALGAR NPS42

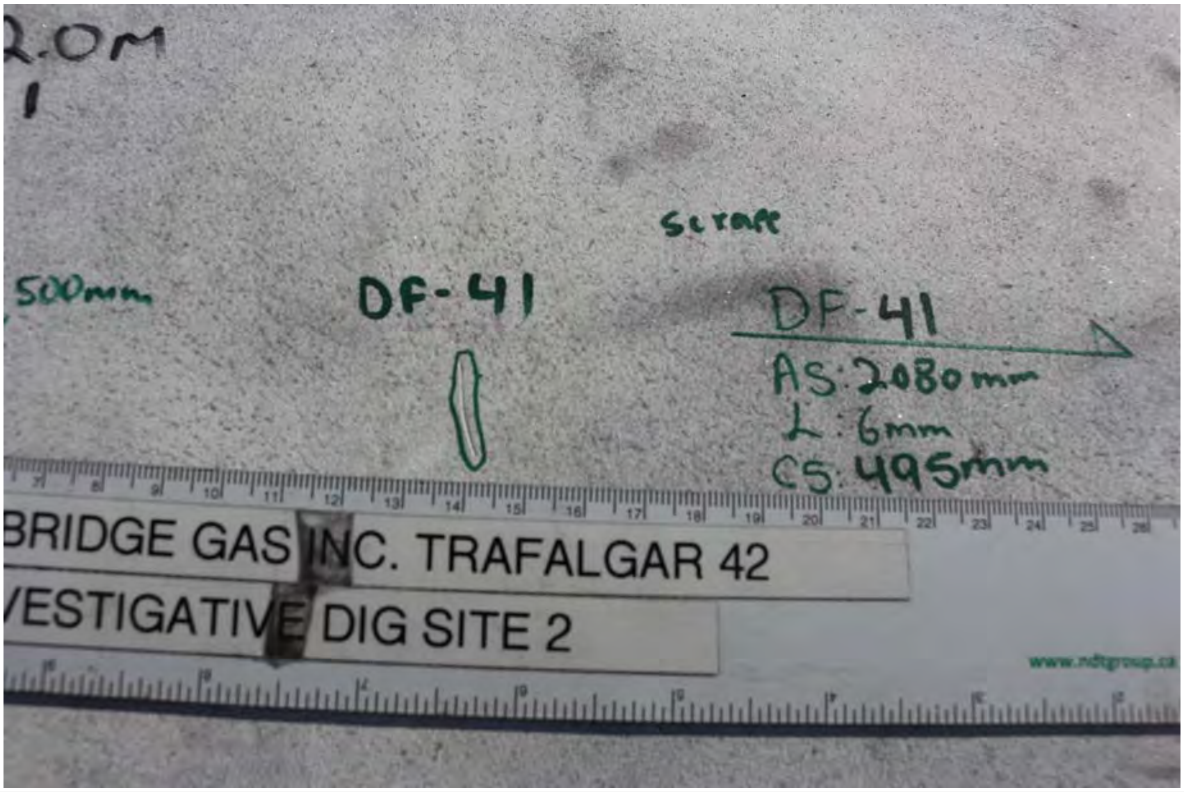


127 - DF-40 CLOSE UP

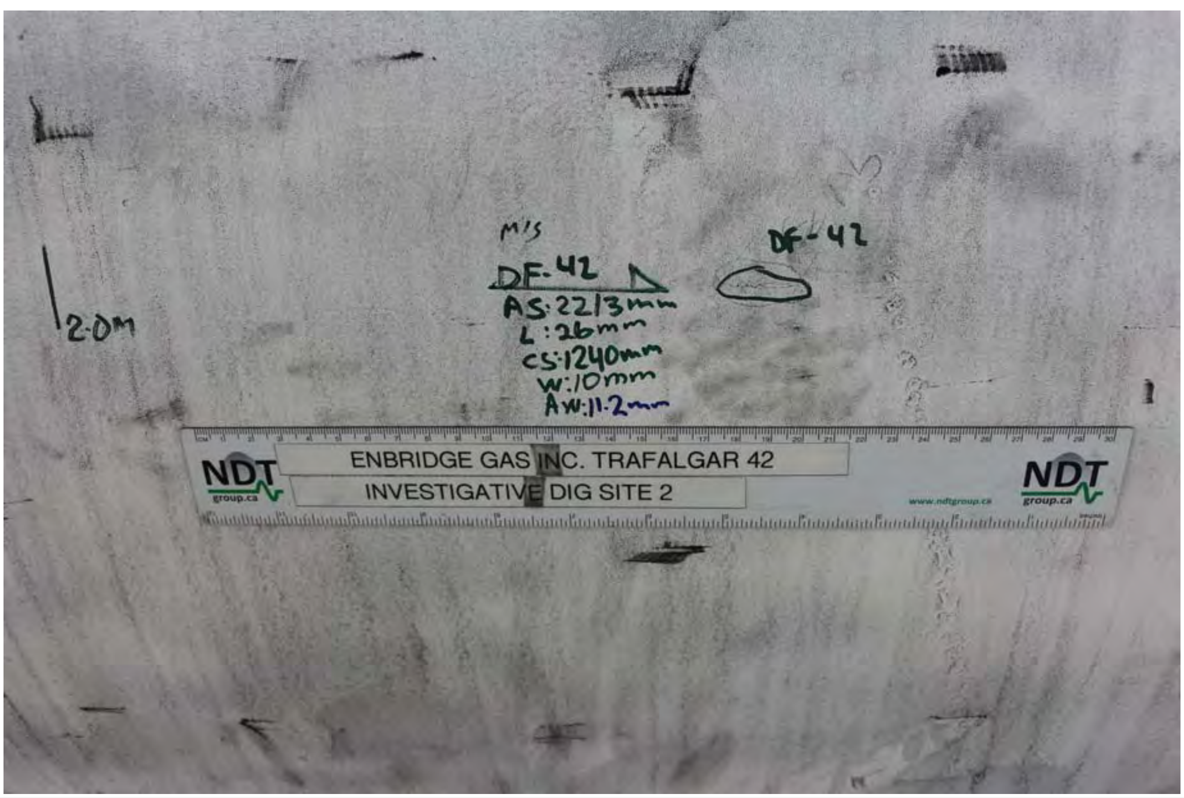


128 - DF-41

ENBRIDGE GAS INC. - TRAFALGAR NPS42

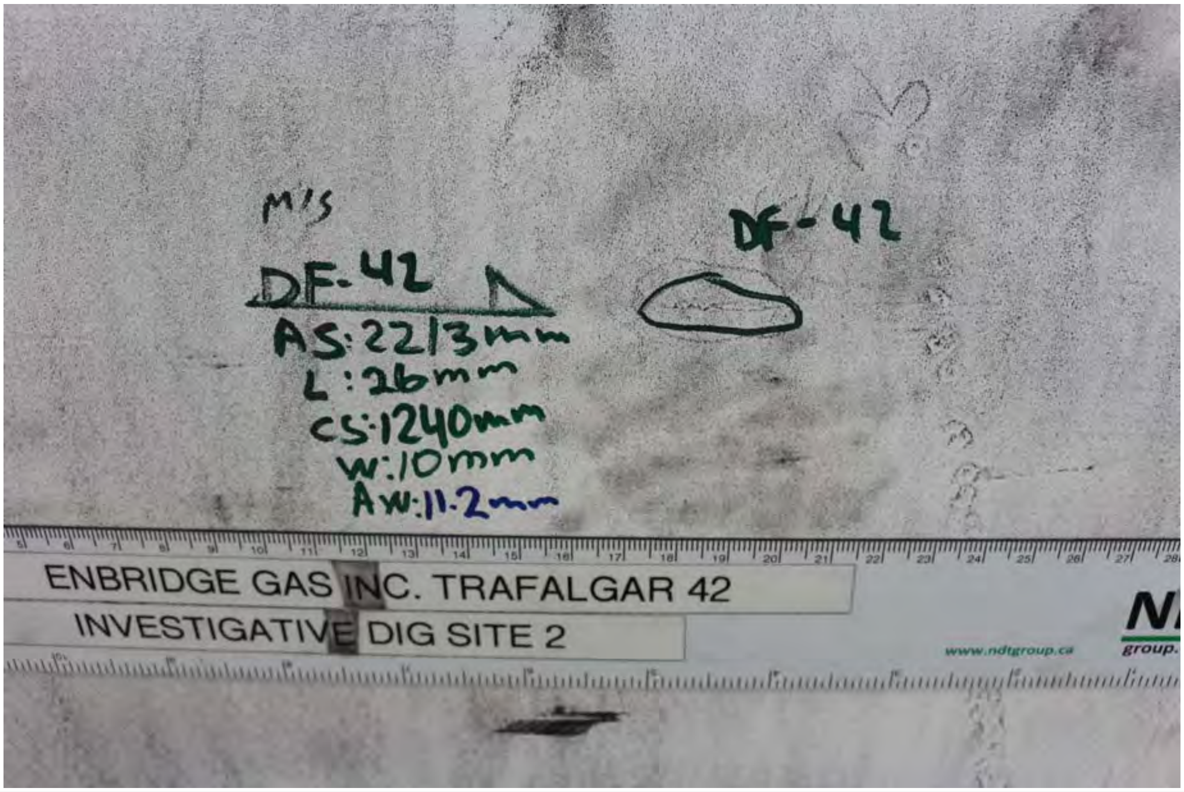


129 - DF-41 CLOSE UP

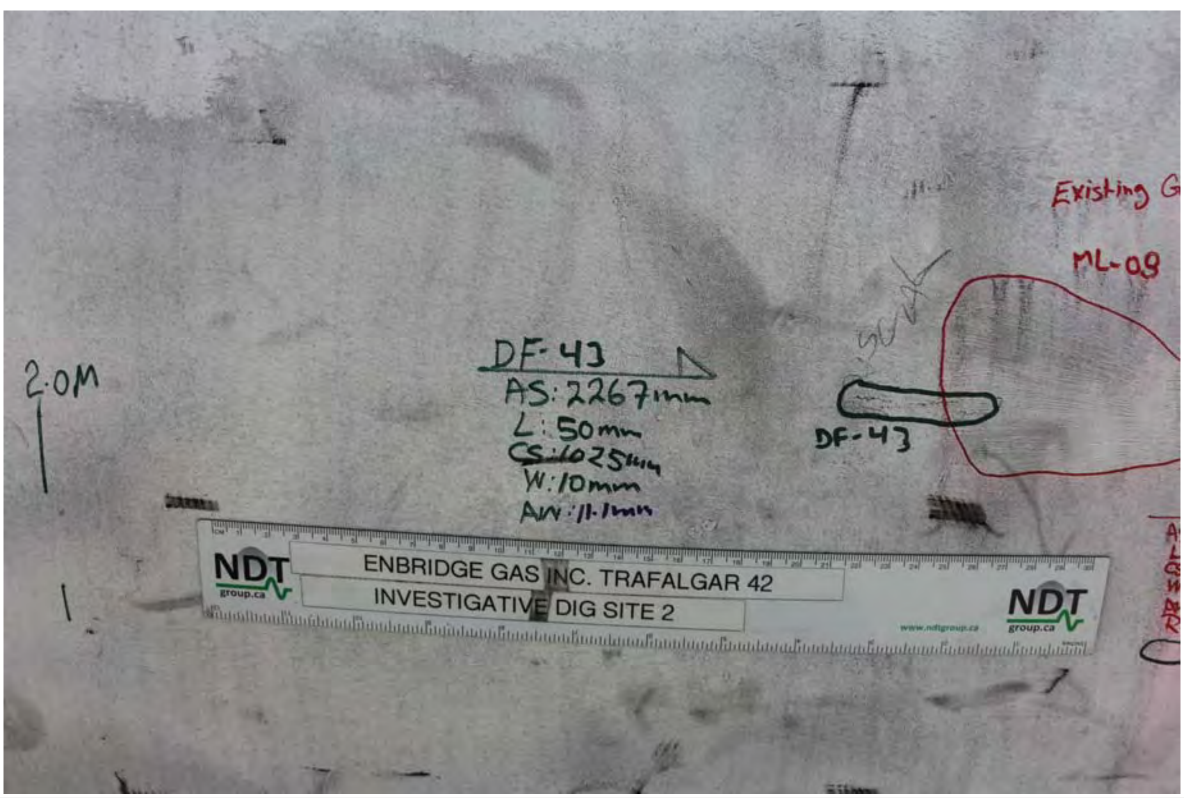


130 - DF-42

ENBRIDGE GAS INC. - TRAFALGAR NPS42

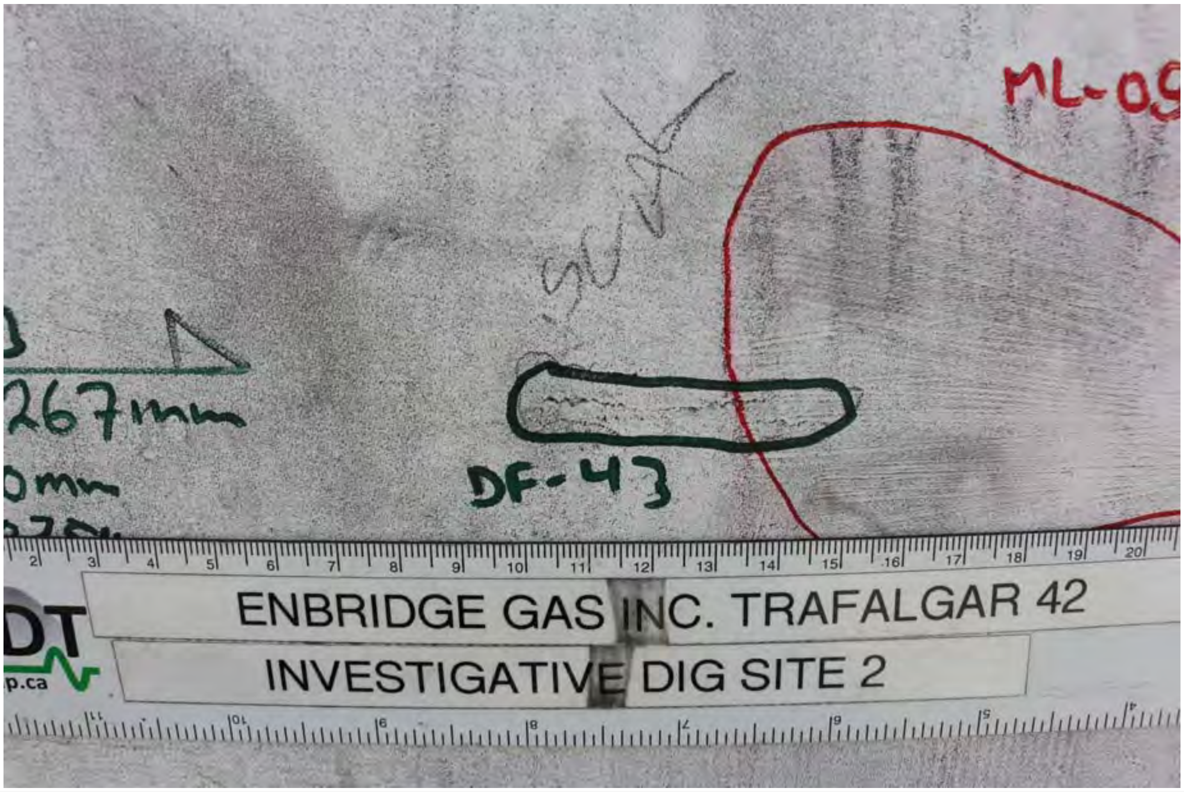


131 - DF-42 CLOSE UP

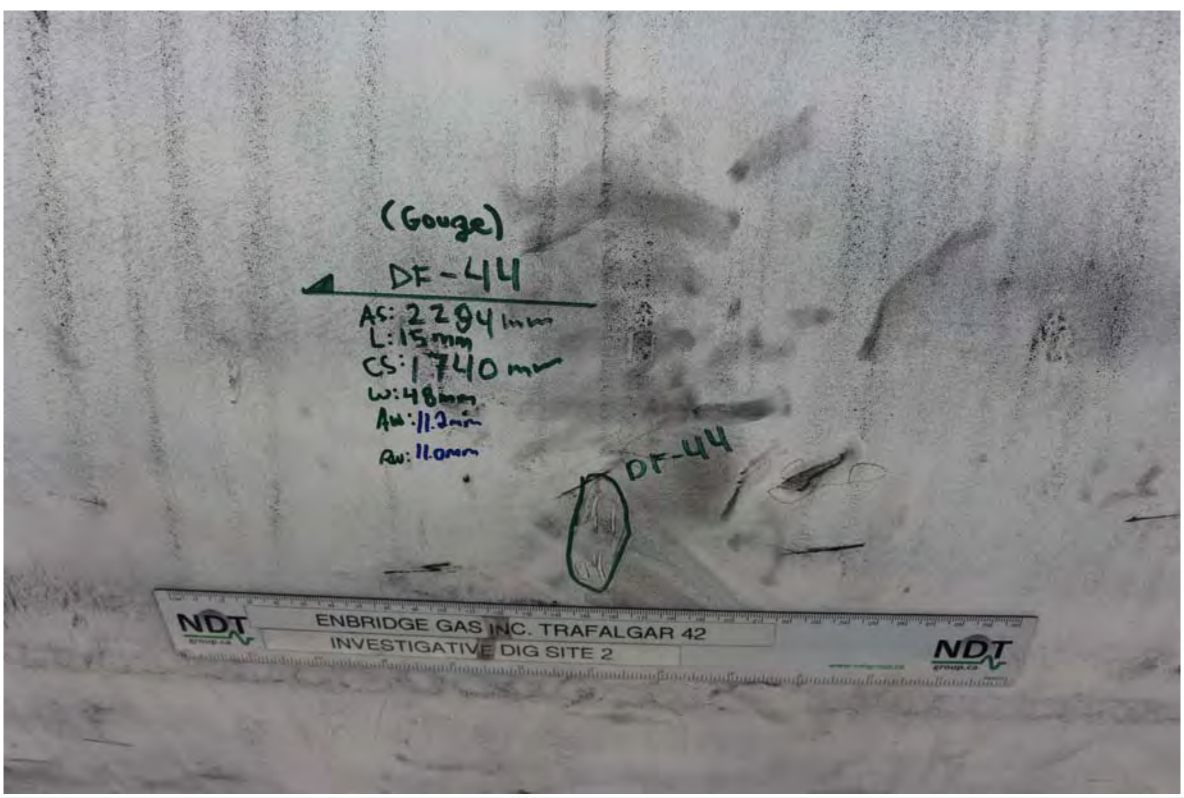


132 - DF-43

ENBRIDGE GAS INC. - TRAFALGAR NPS42

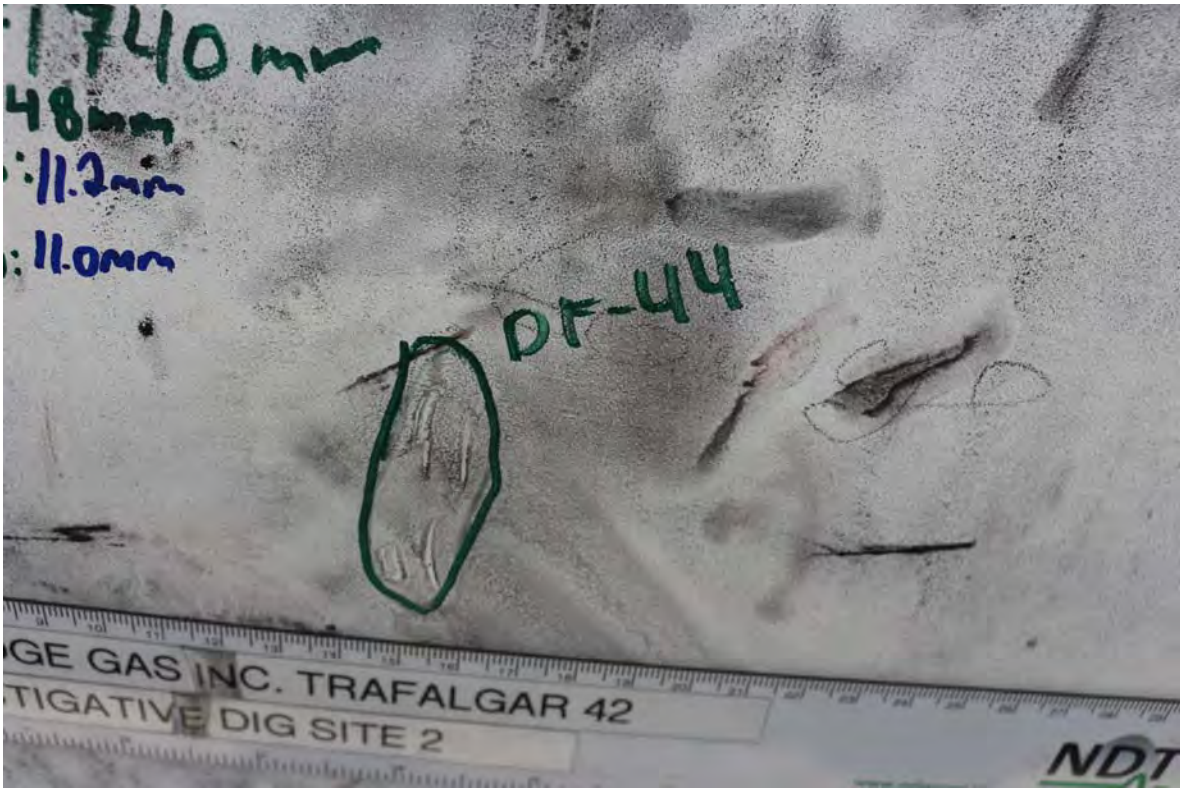


133 - DF-43 CLOSE UP

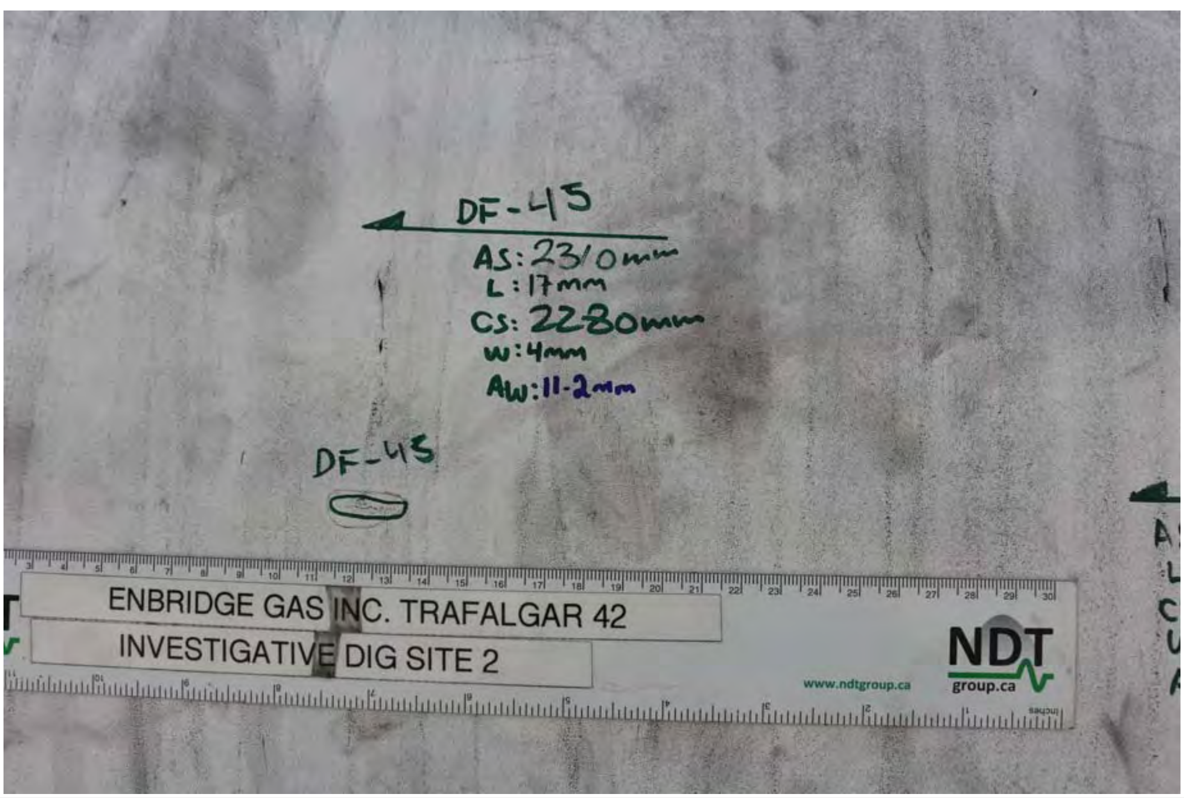


134 - DF-44

ENBRIDGE GAS INC. - TRAFALGAR NPS42

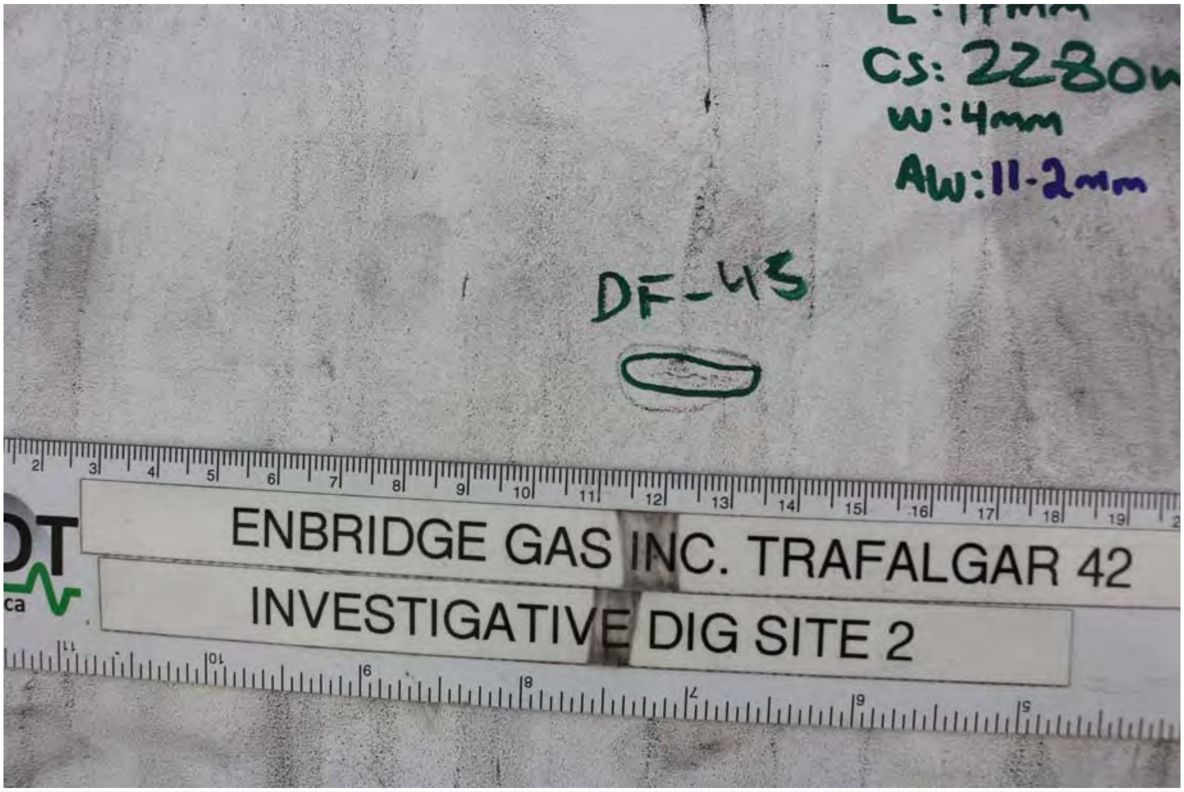


135 - DF-44 CLOSE UP

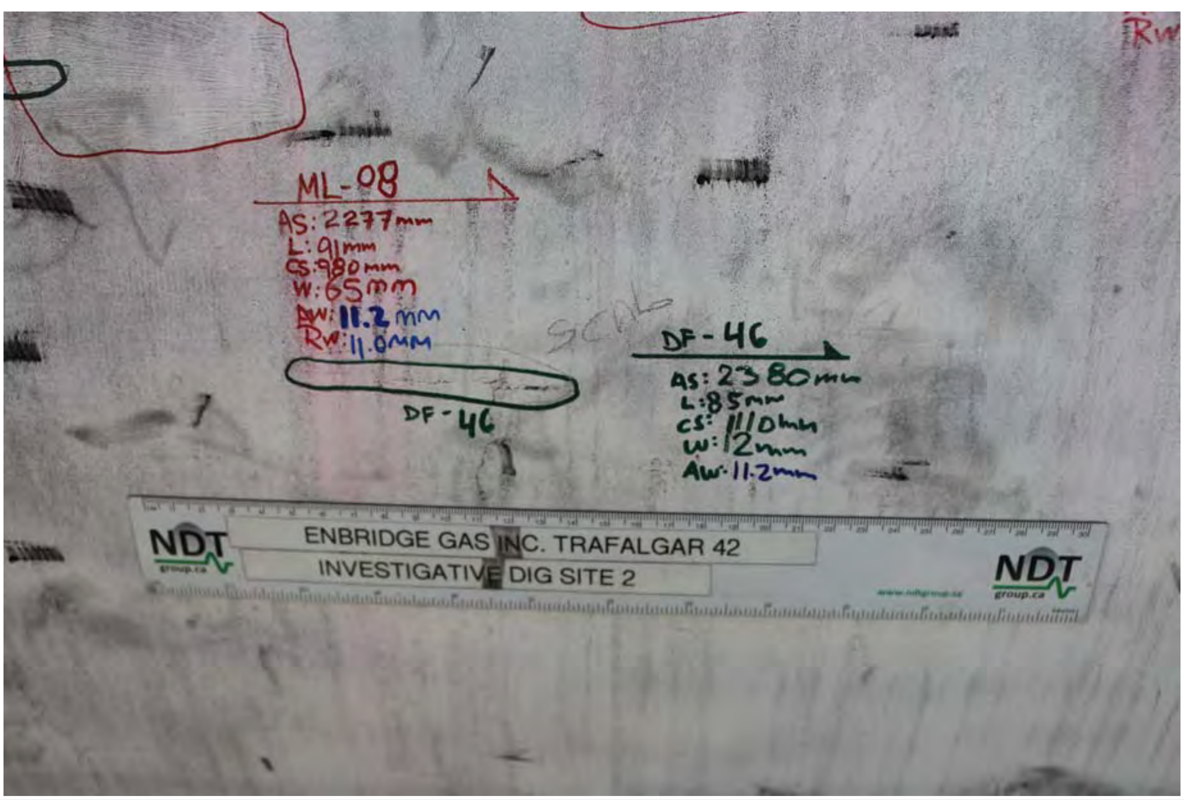


136 - DF-45

ENBRIDGE GAS INC. - TRAFALGAR NPS42

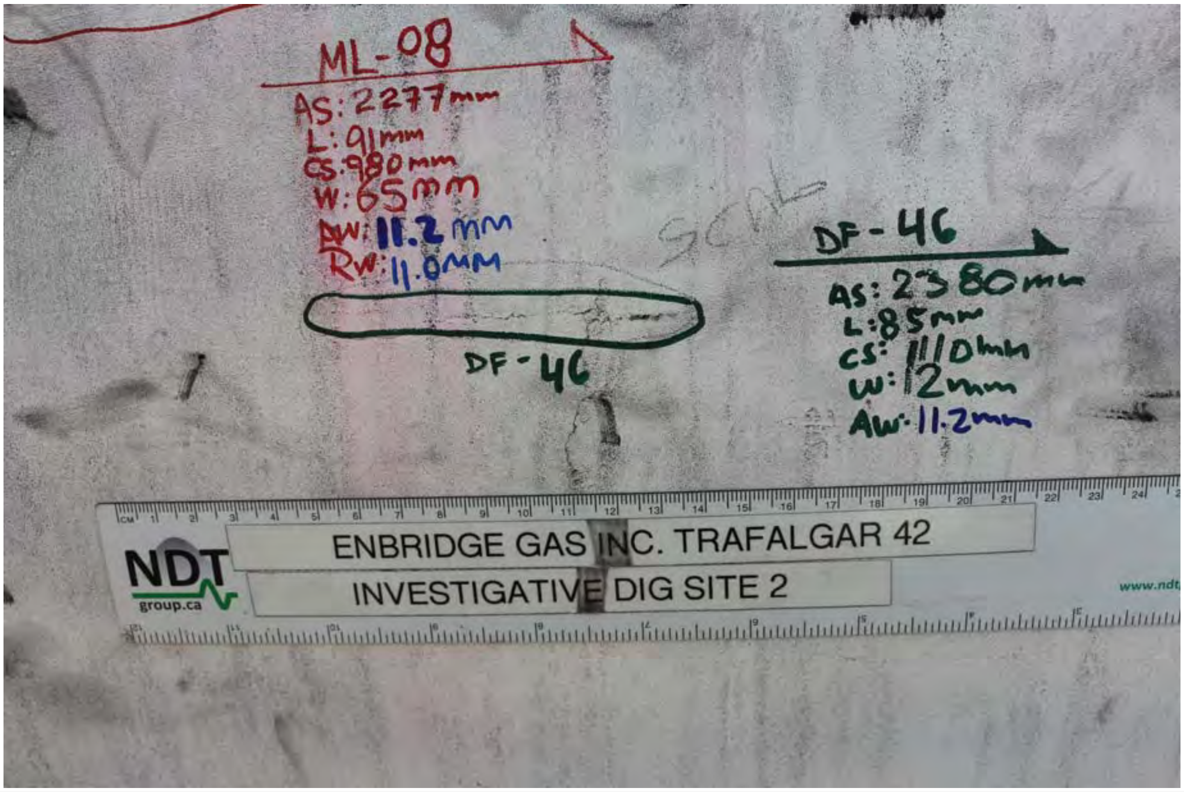


137 - DF-45 CLOSE UP

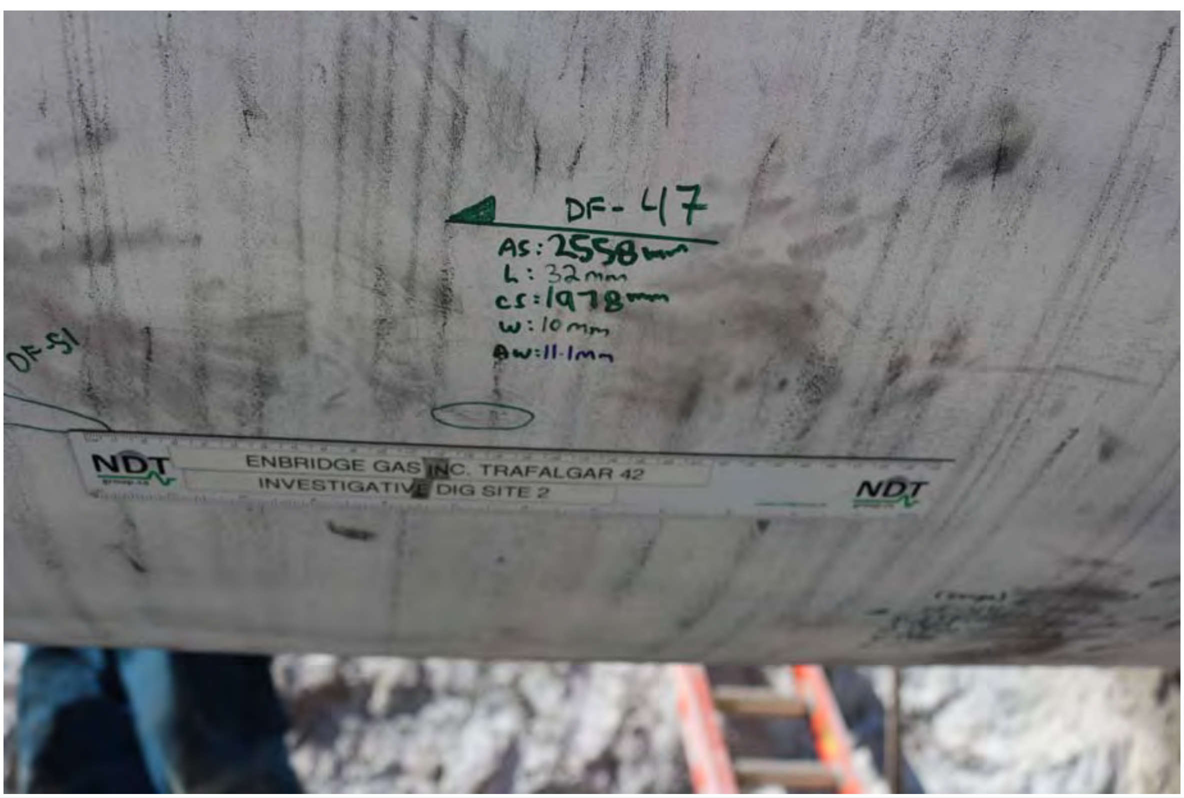


138 - DF-46

ENBRIDGE GAS INC. - TRAFALGAR NPS42

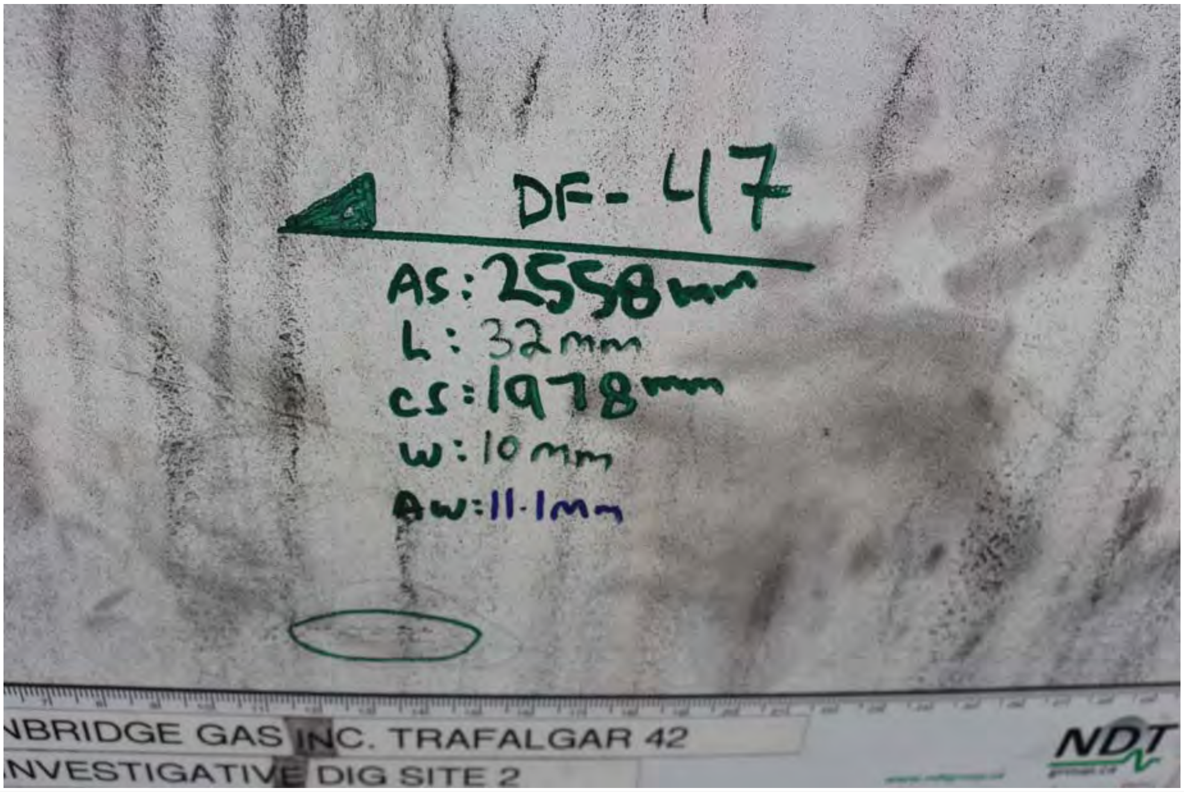


139 - DF-46 CLOSE UP

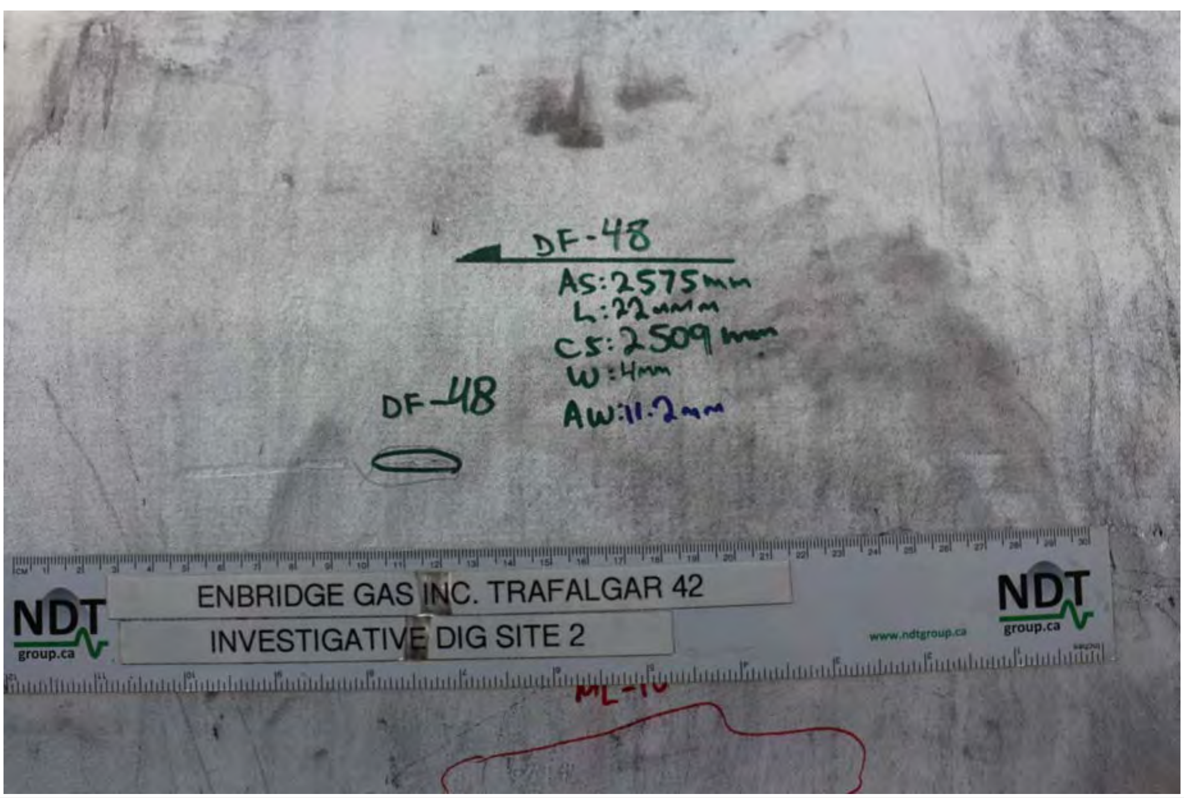


140 - DF-47

ENBRIDGE GAS INC. - TRAFALGAR NPS42

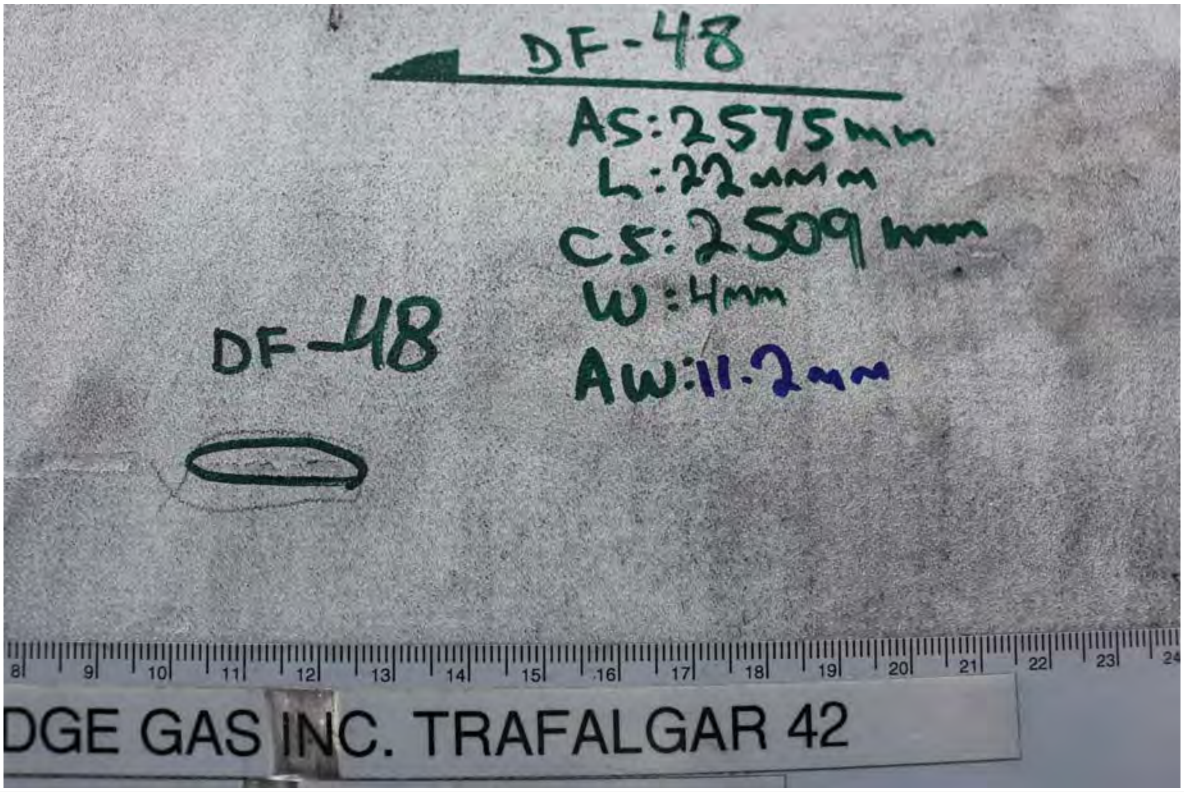


141 - DF-47 CLOSE UP

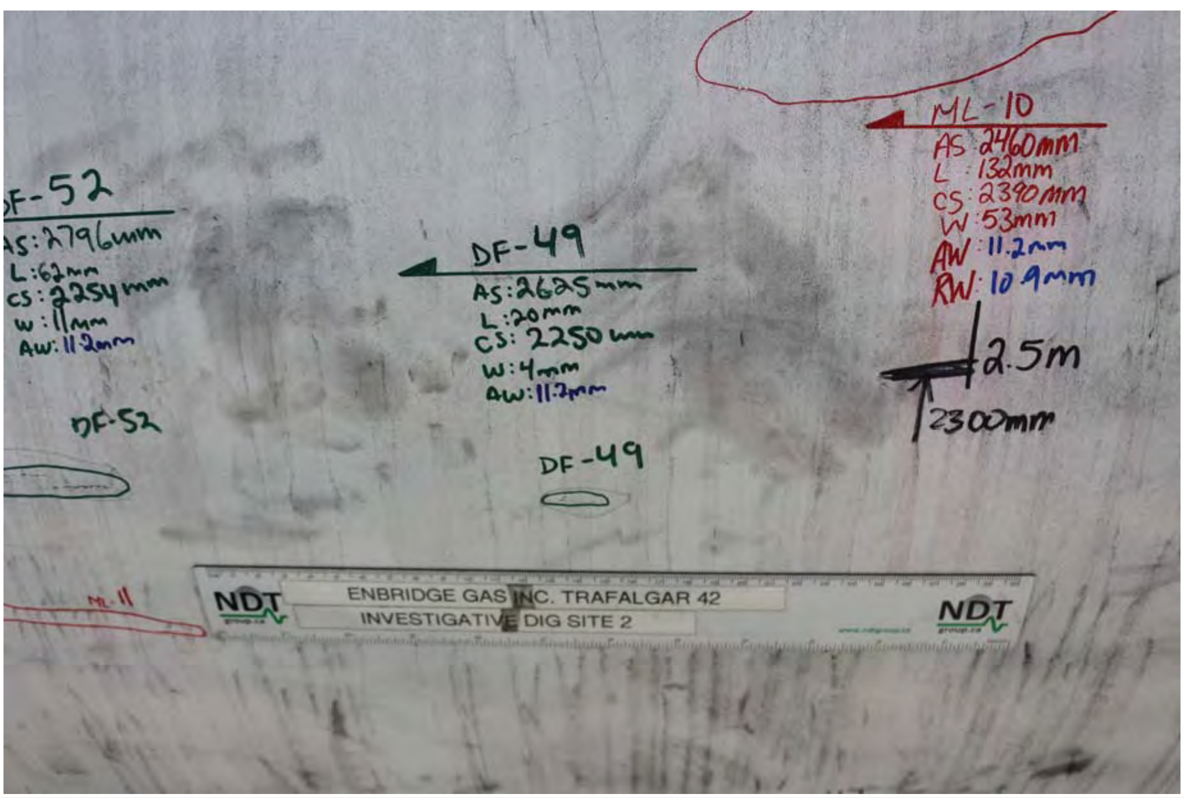


142 - DF-48

ENBRIDGE GAS INC. - TRAFALGAR NPS42

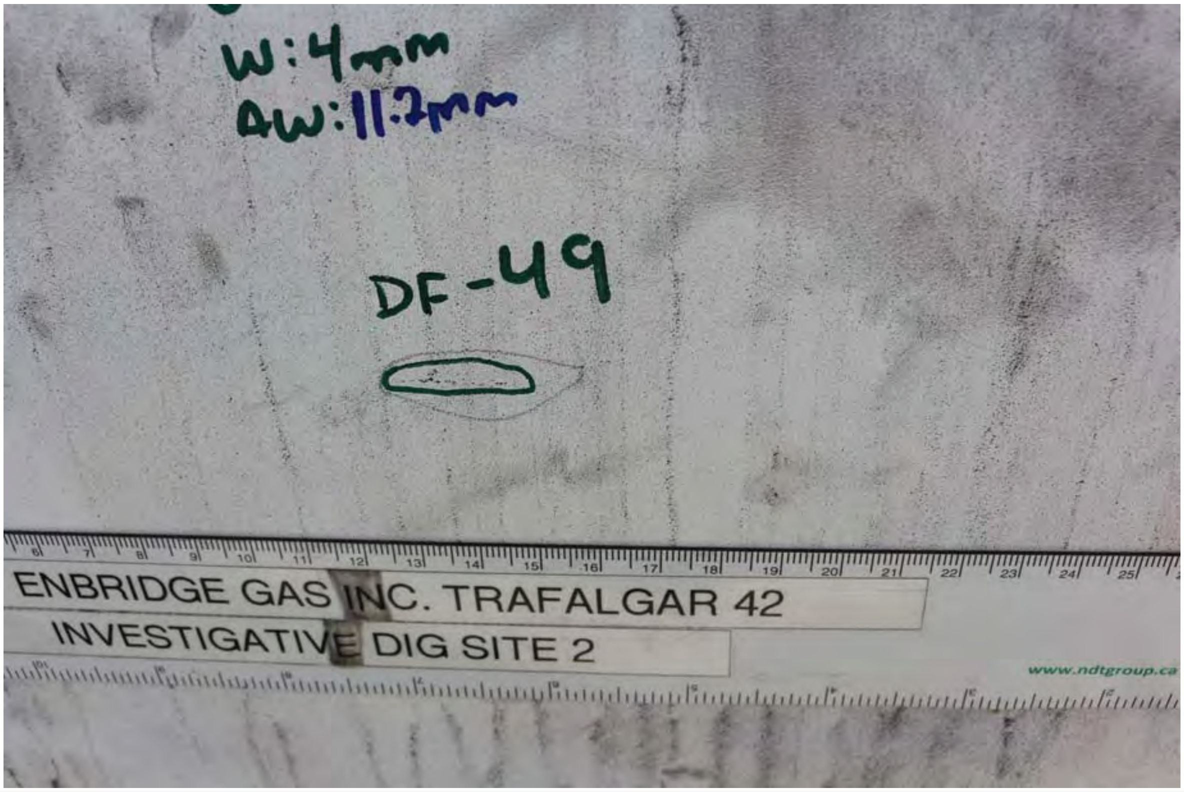


143 - DF-48 CLOSE UP

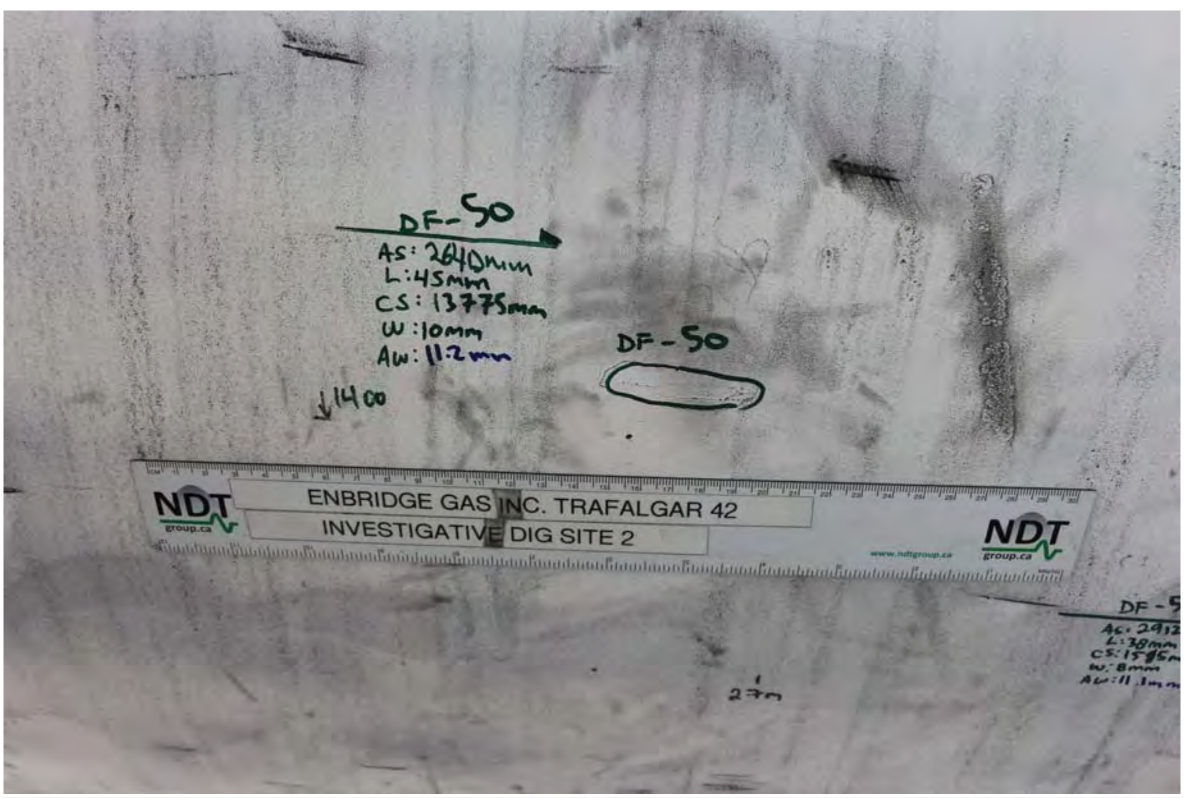


144 - DF-49

ENBRIDGE GAS INC. - TRAFALGAR NPS42

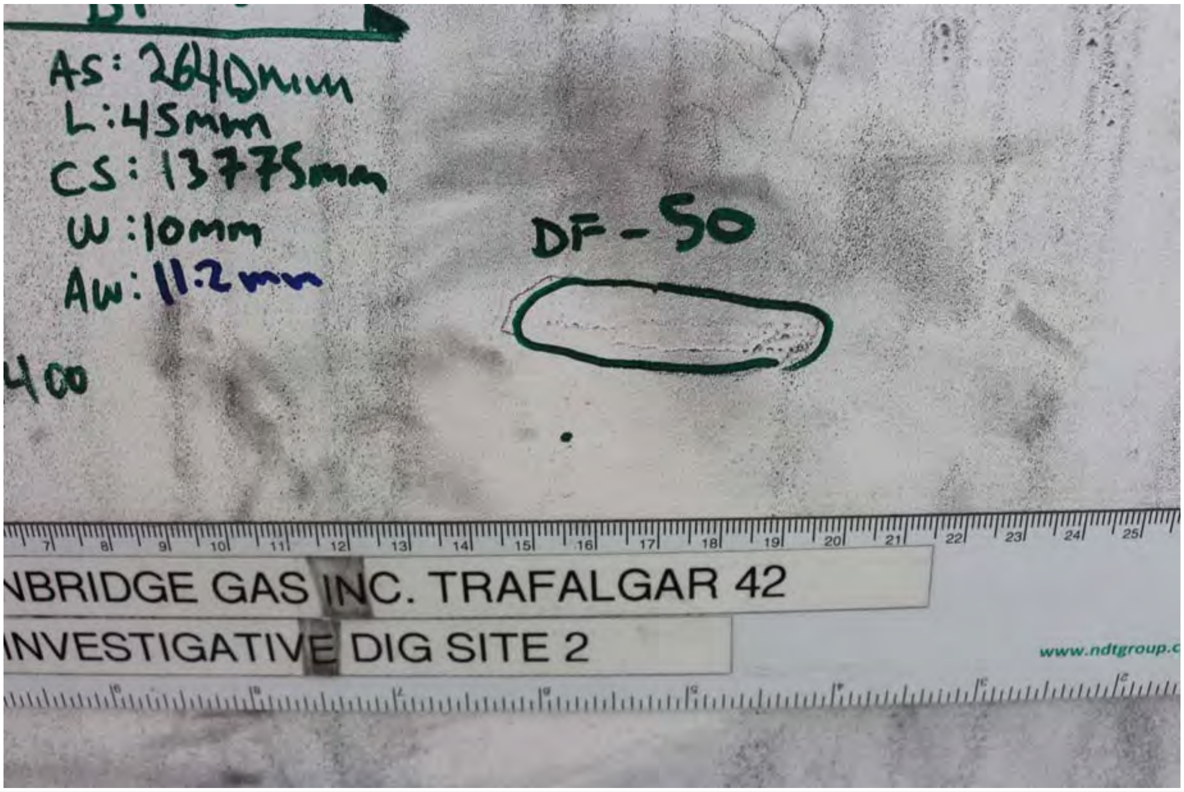


145 - DF-49 CLOSE UP

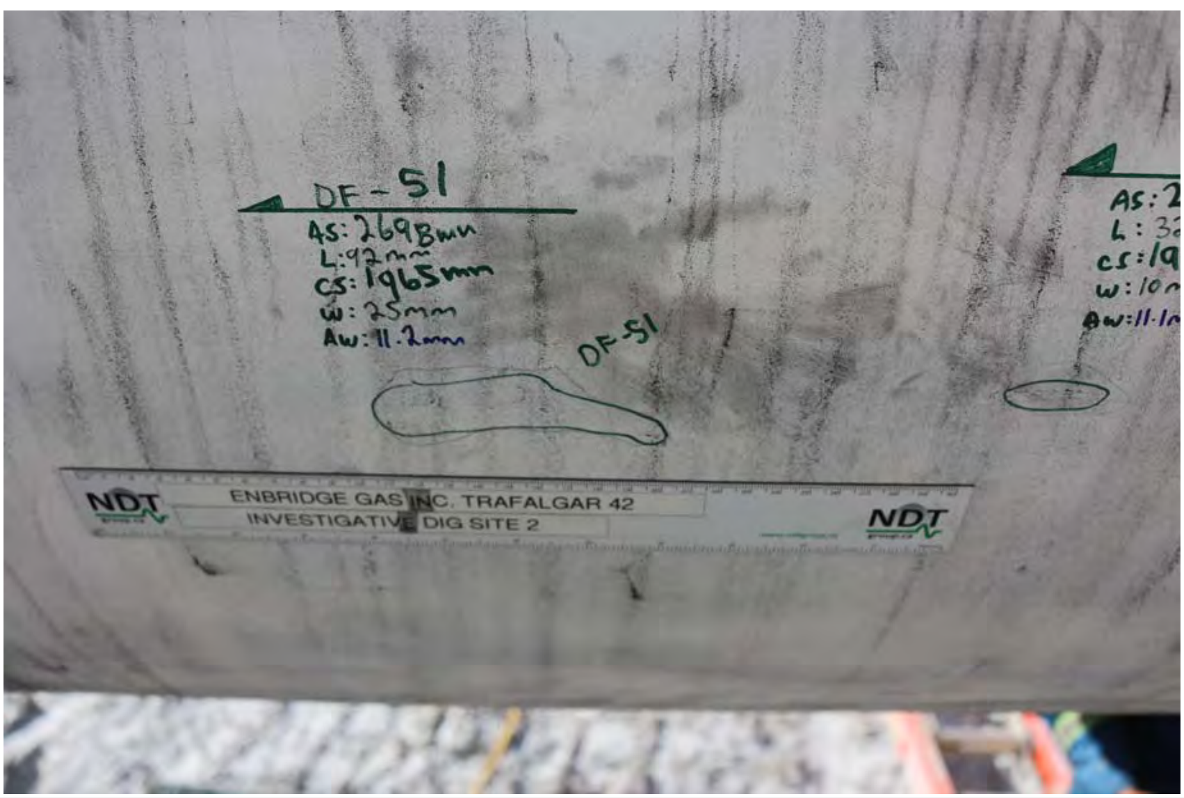


146 - DF-50

ENBRIDGE GAS INC. - TRAFALGAR NPS42

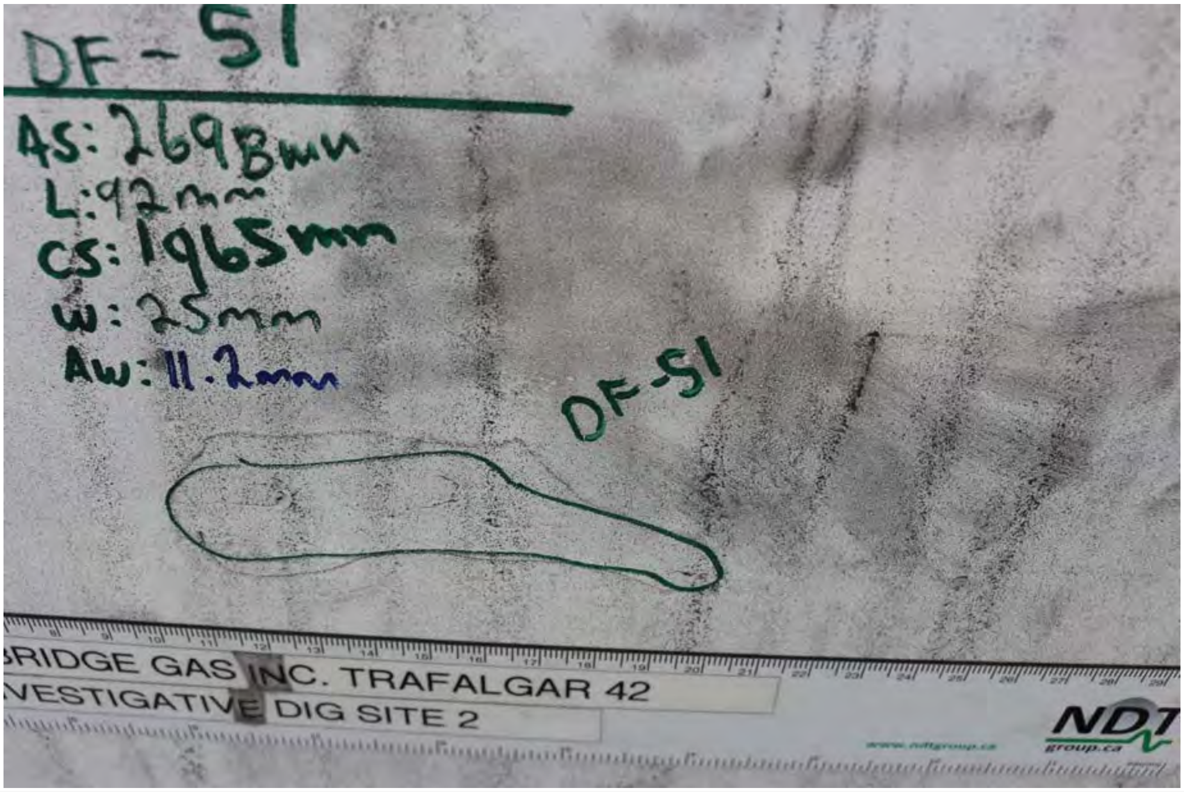


147 - DF-50 CLOSE UP

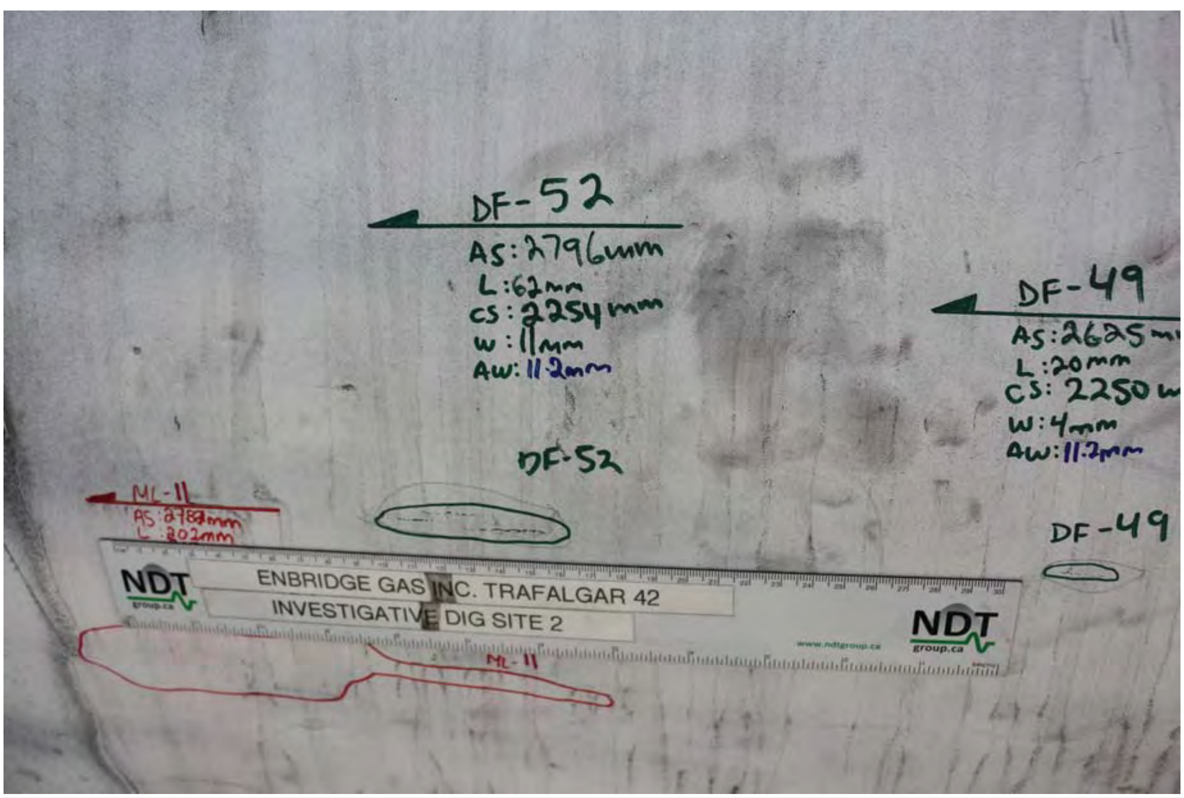


148 - DF-51

ENBRIDGE GAS INC. - TRAFALGAR NPS42

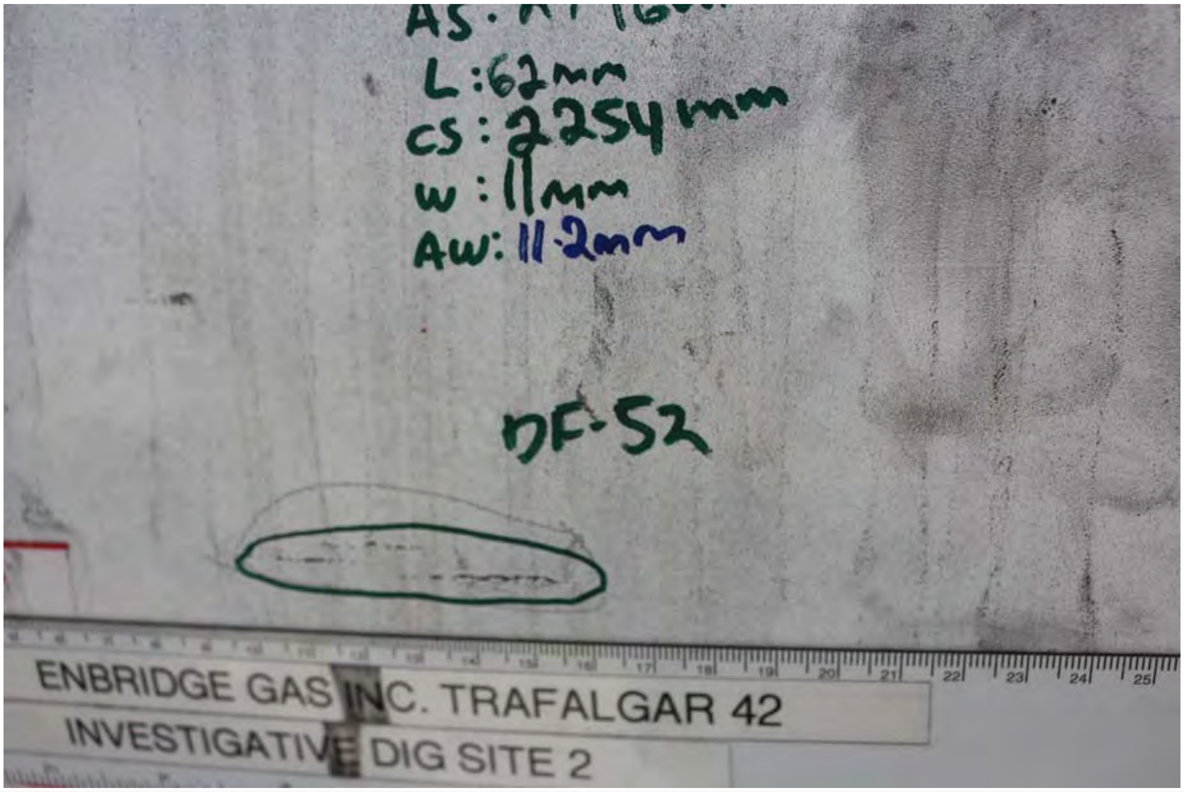


149 - DF-51 CLOSE UP

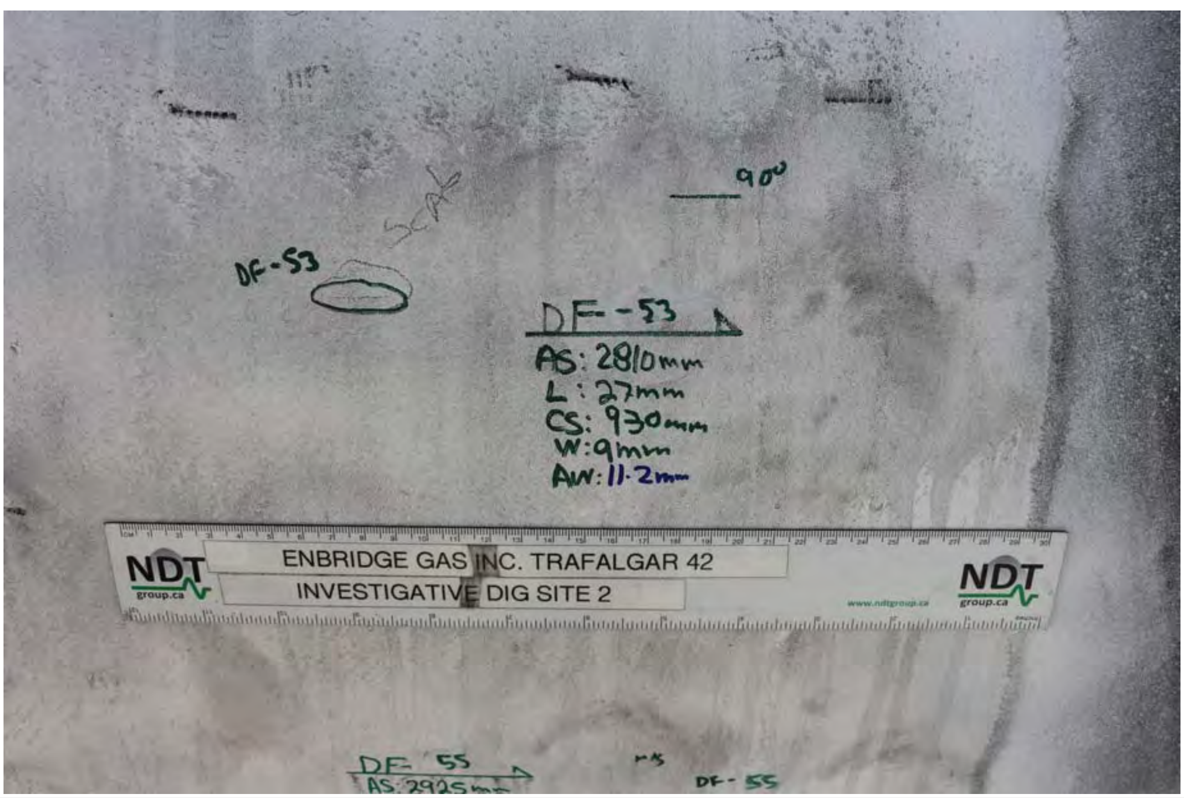


150 - DF-52

ENBRIDGE GAS INC. - TRAFALGAR NPS42

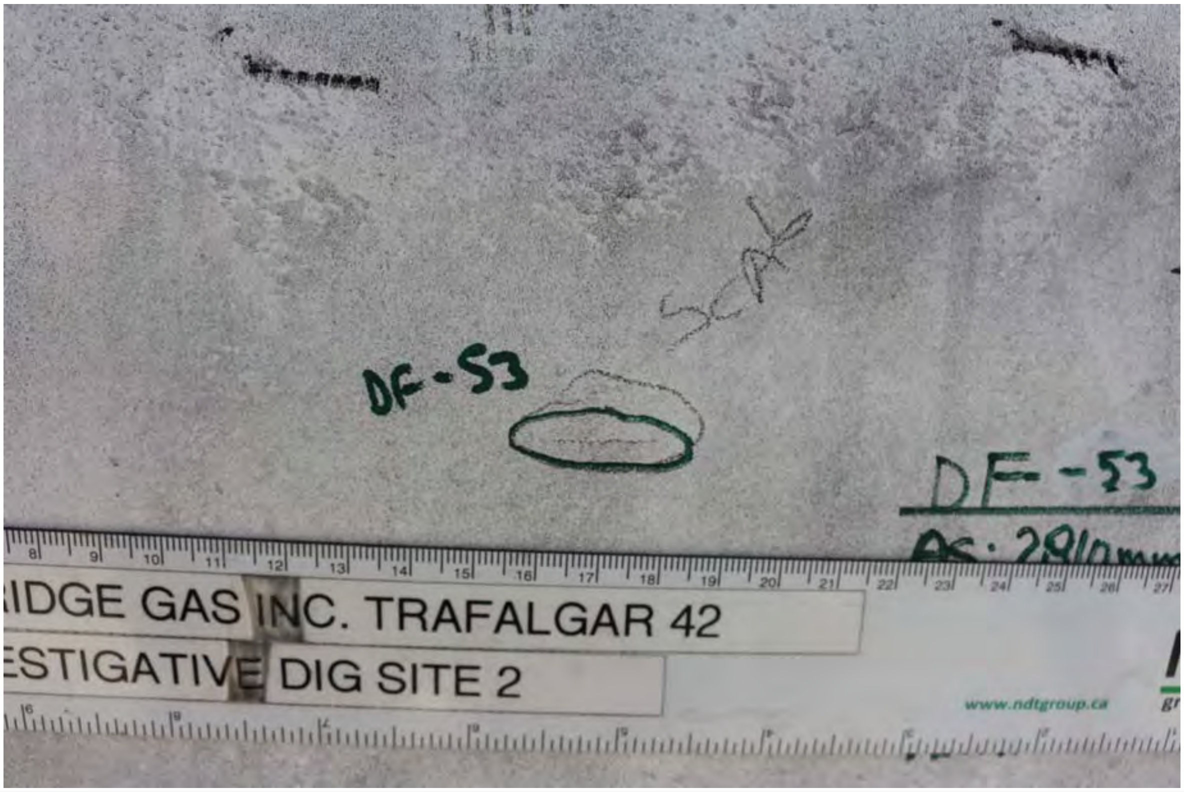


151 - DF-52 CLOSE UP

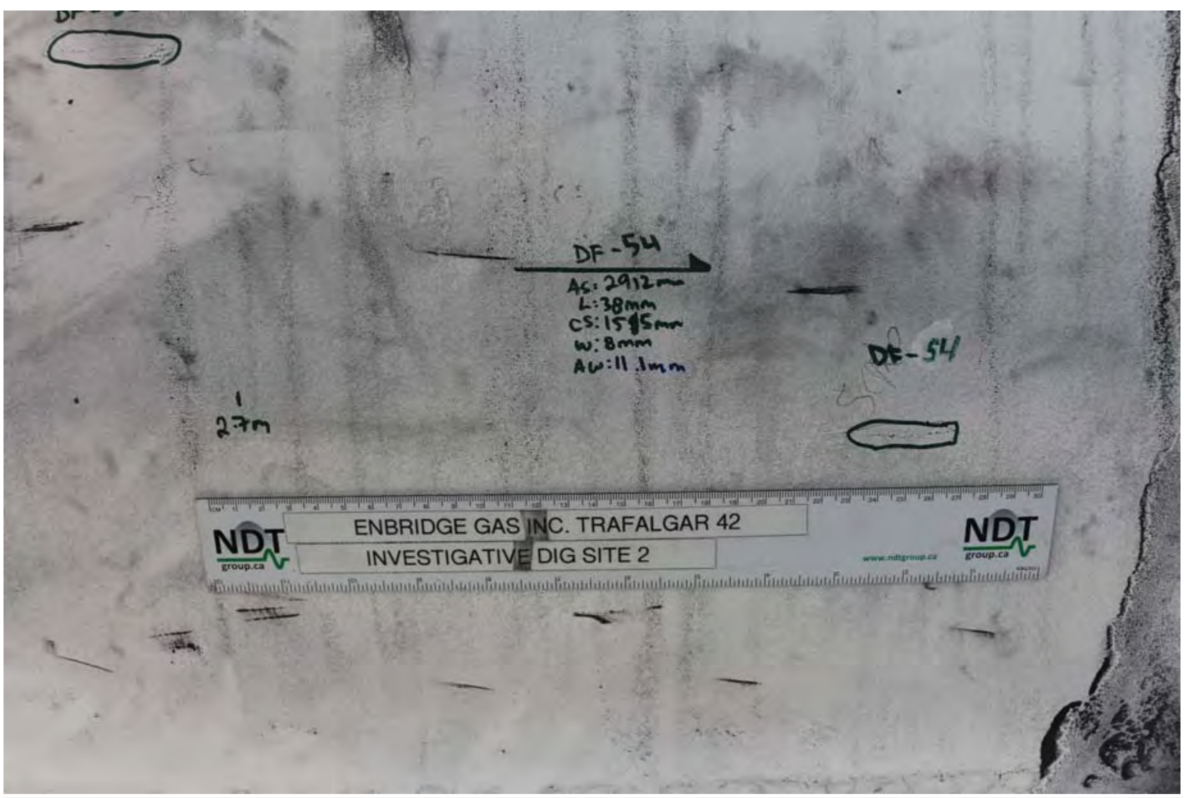


152 - DF-53

ENBRIDGE GAS INC. - TRAFALGAR NPS42

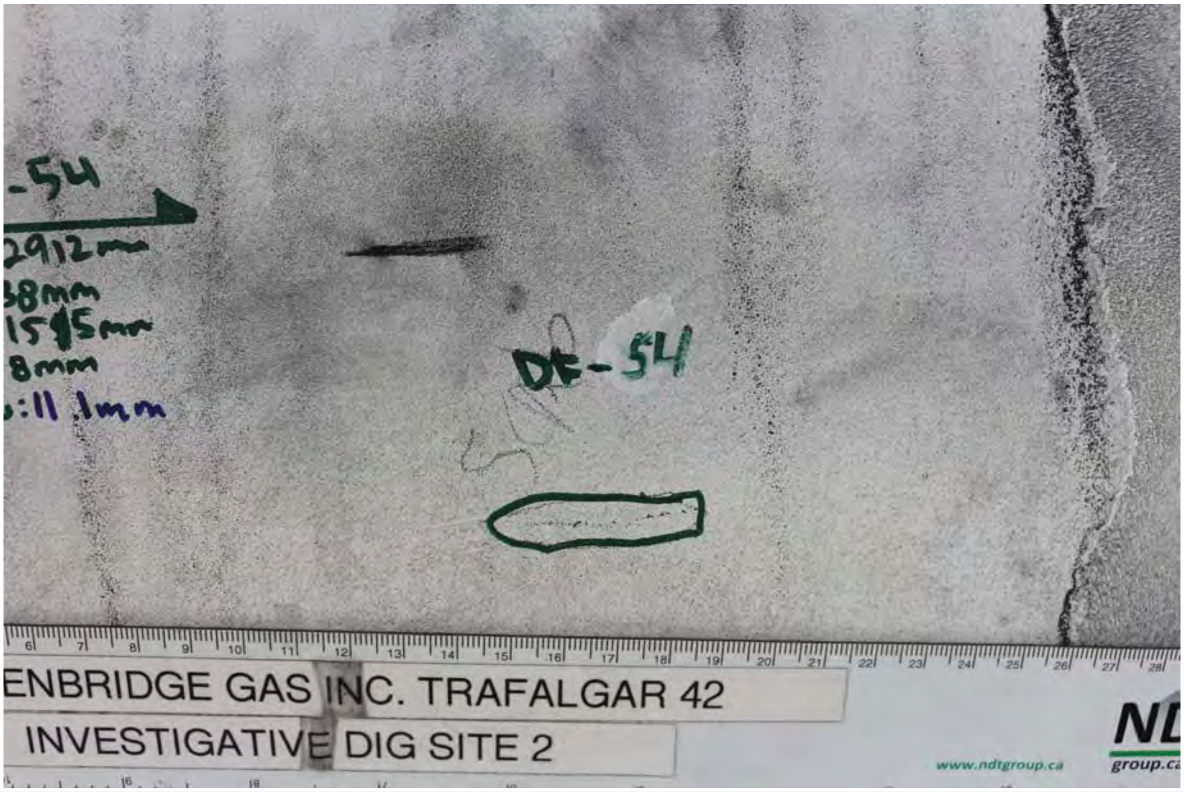


153 - DF-53 CLOSE UP

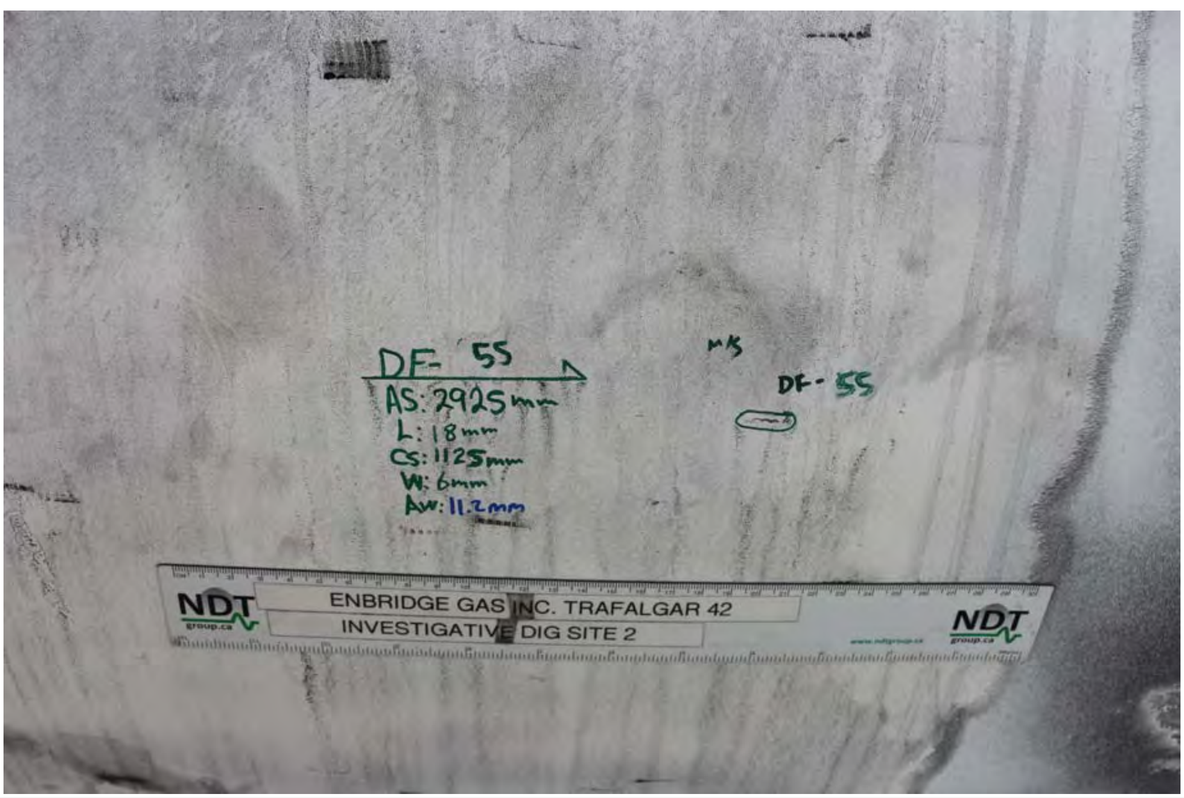


154 - DF-54

ENBRIDGE GAS INC. - TRAFALGAR NPS42

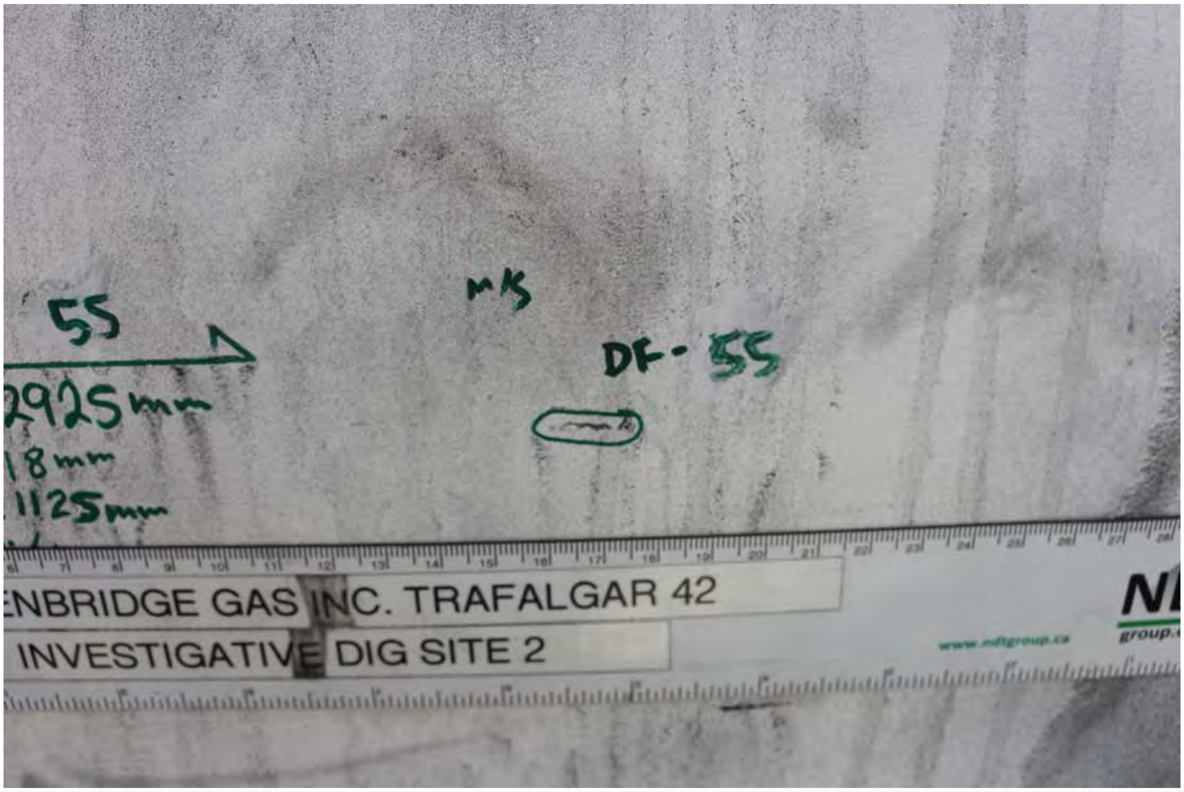


155 - DF-54 CLOSE UP

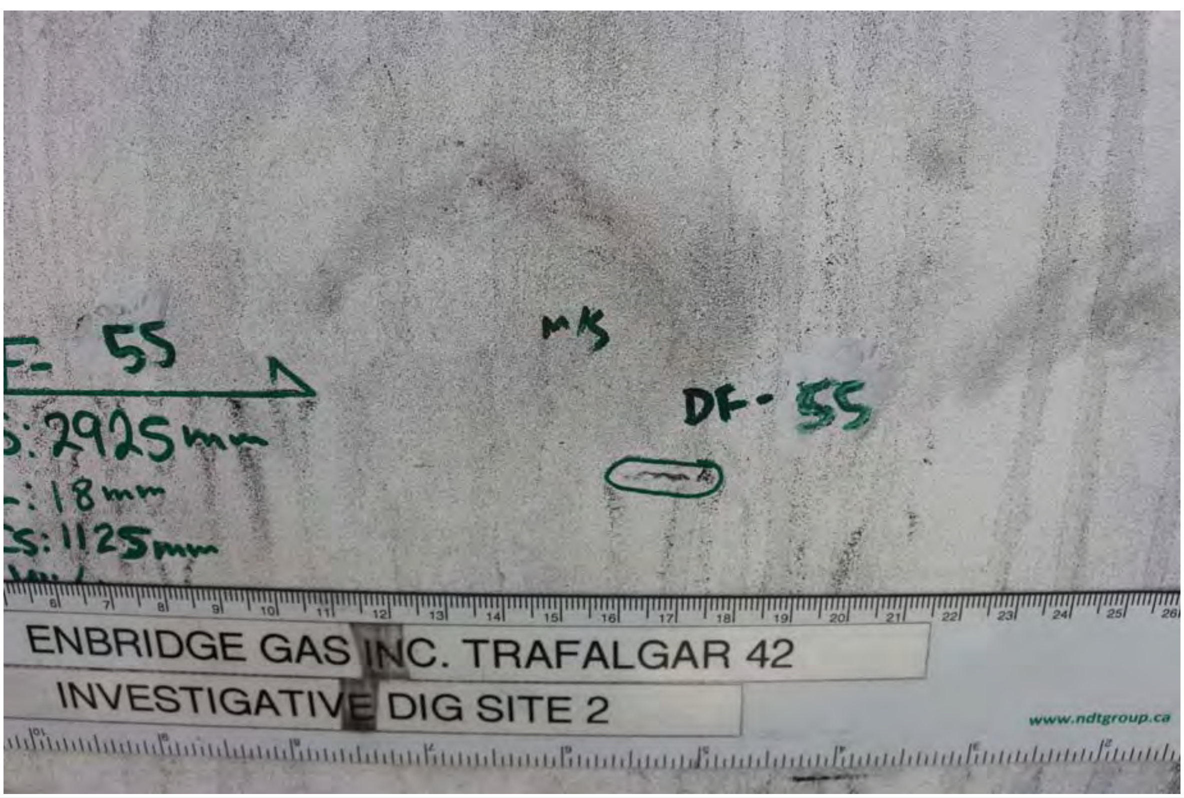


156 - DF-55

ENBRIDGE GAS INC. - TRAFALGAR NPS42

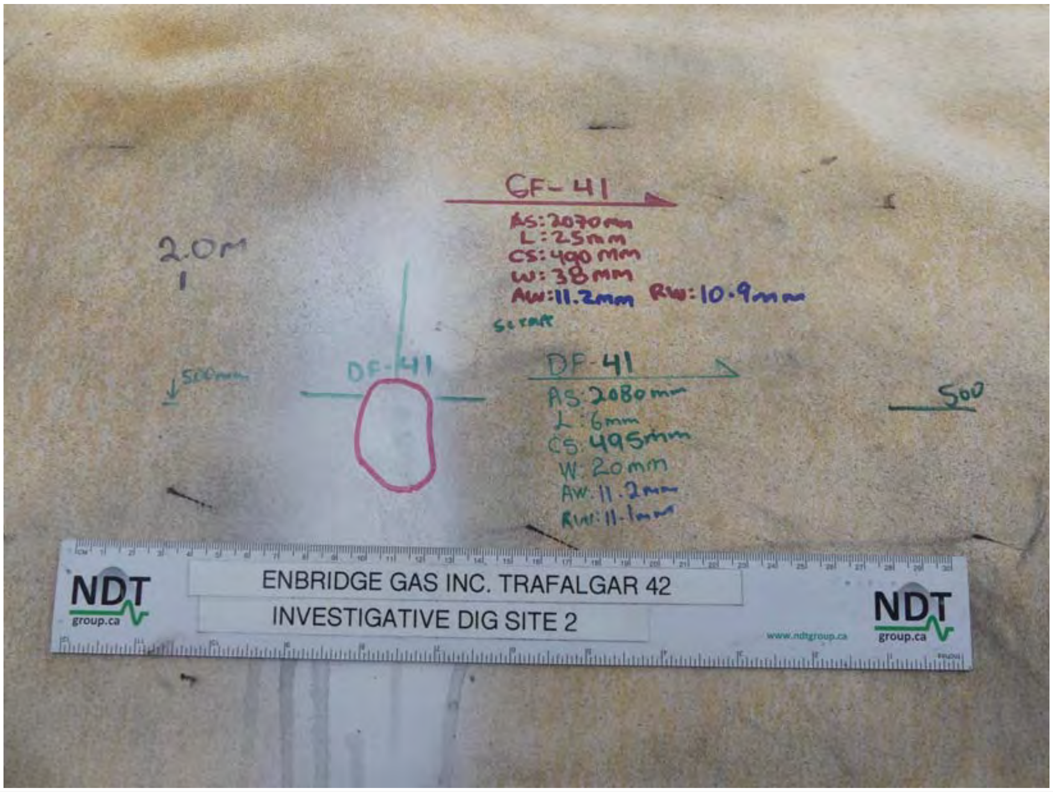


157 - DF-55 CLOSE UP

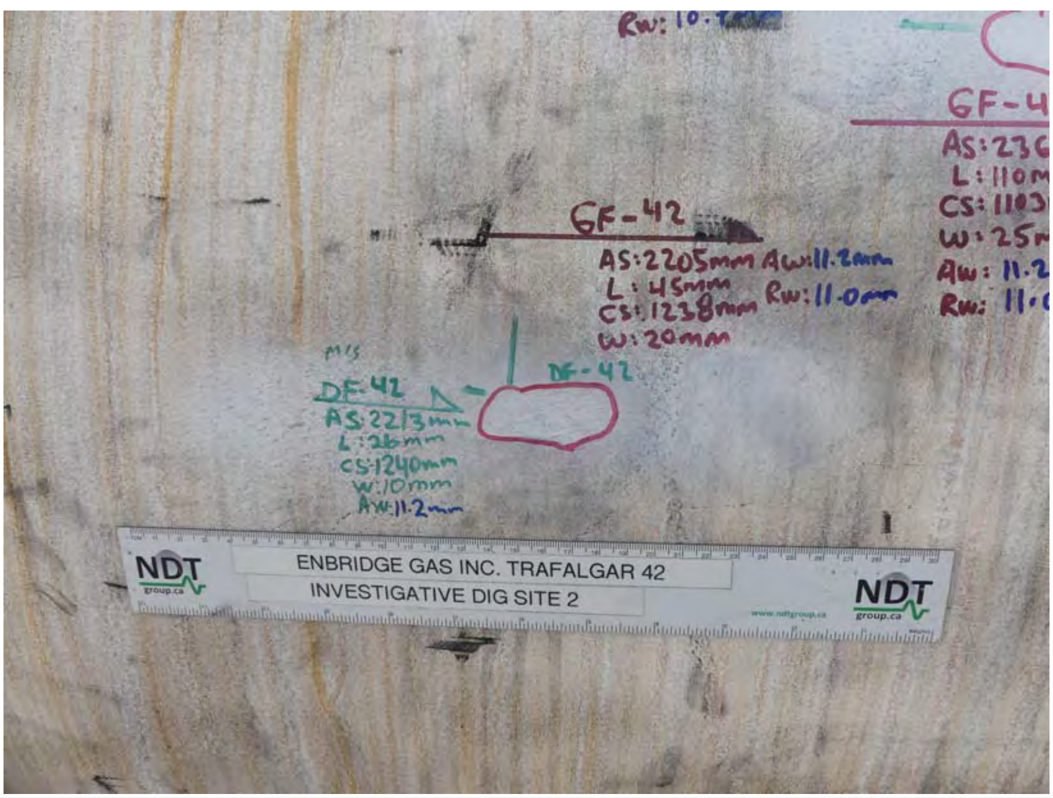


158 - DF-55 CLOSE UP (2)

ENBRIDGE GAS INC. - TRAFALGAR NPS42

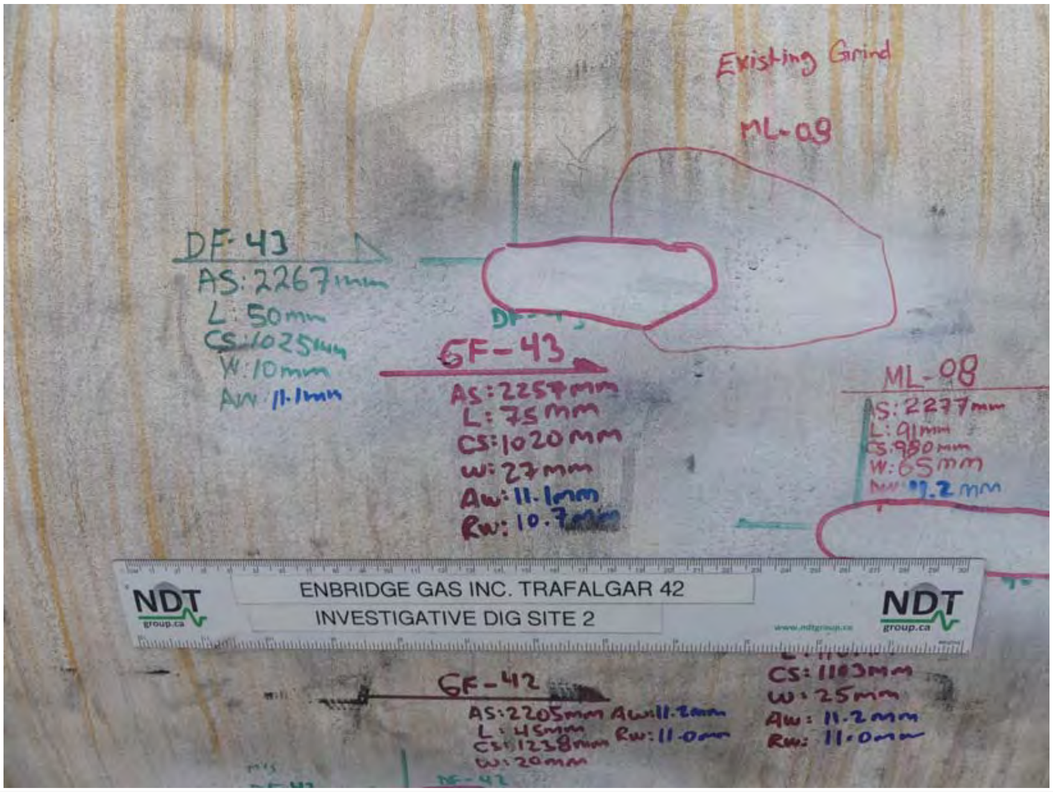


199 - GF-41

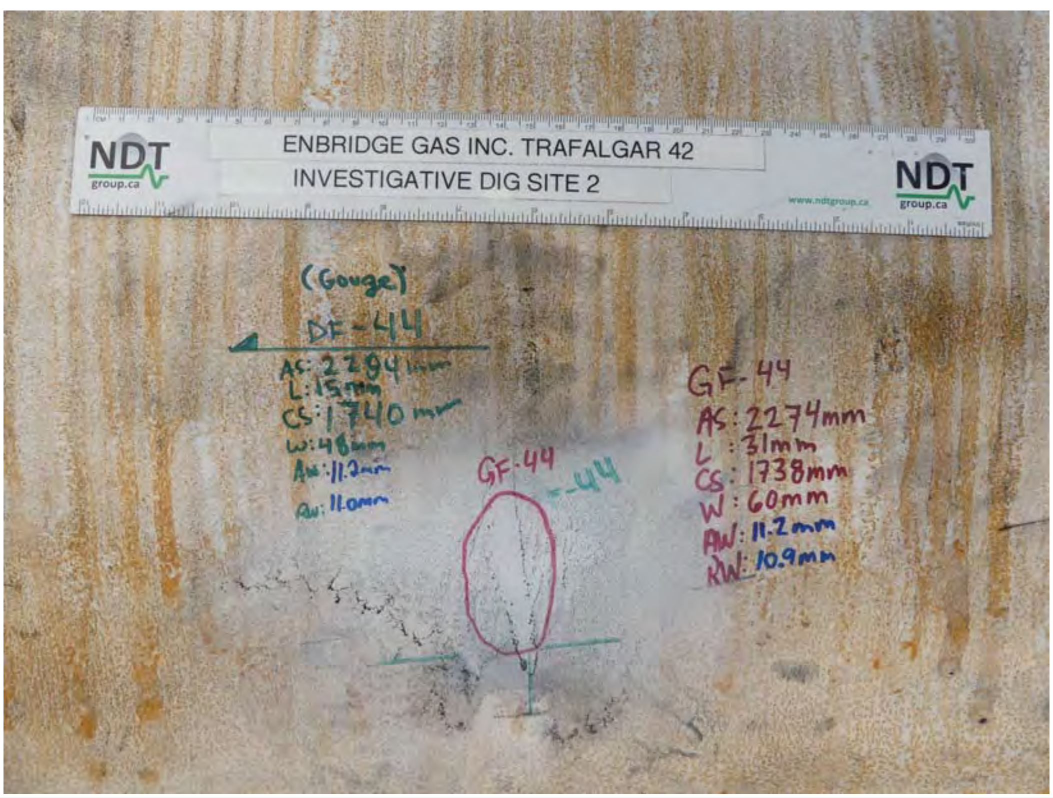


200 - GF-42

ENBRIDGE GAS INC. - TRAFALGAR NPS42

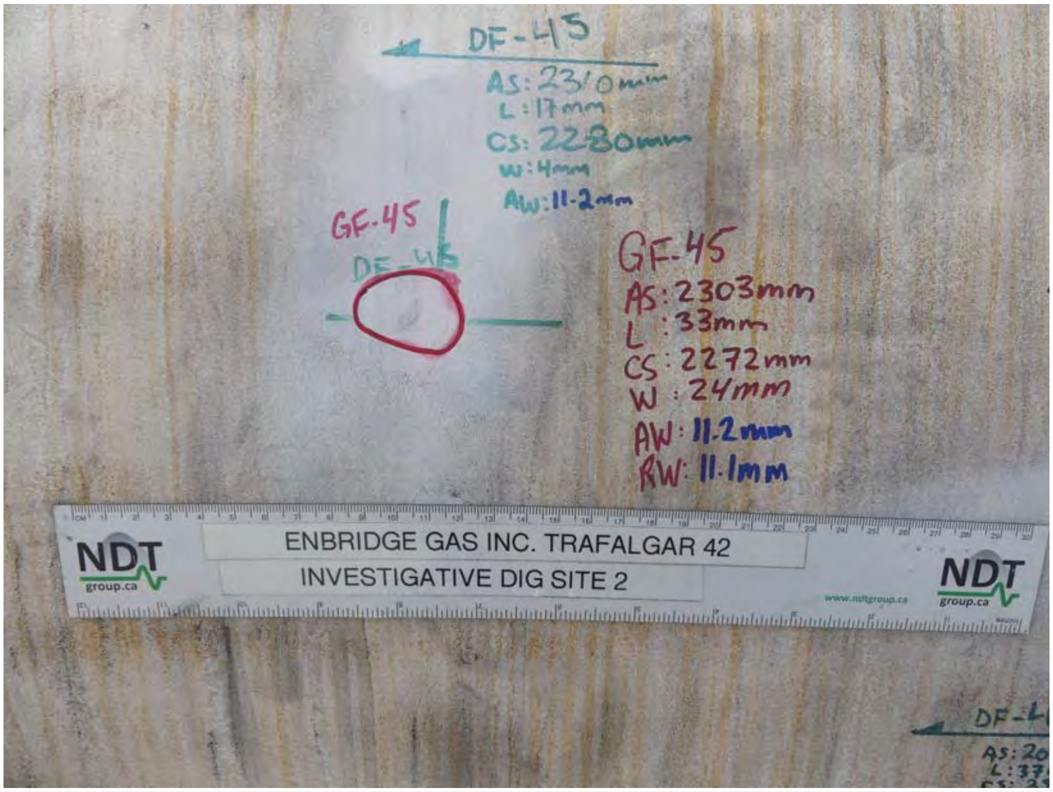


201 - GF-43

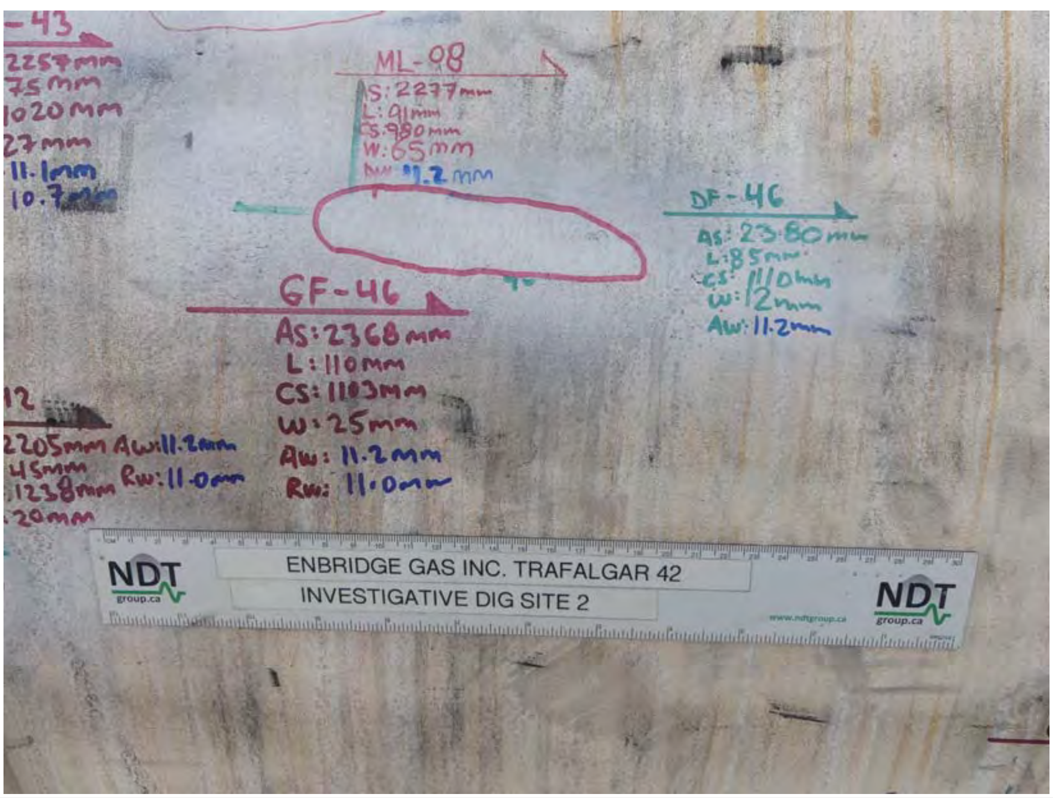


202 - GF-44

ENBRIDGE GAS INC. - TRAFALGAR NPS42



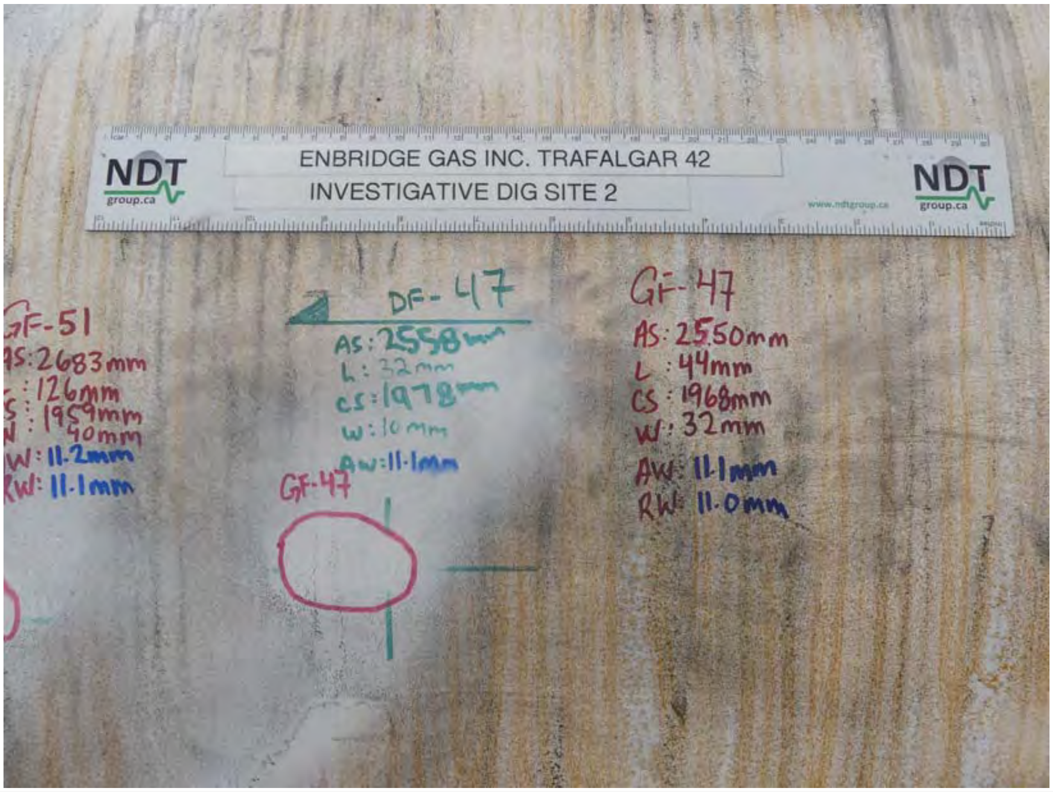
203 - GF-45



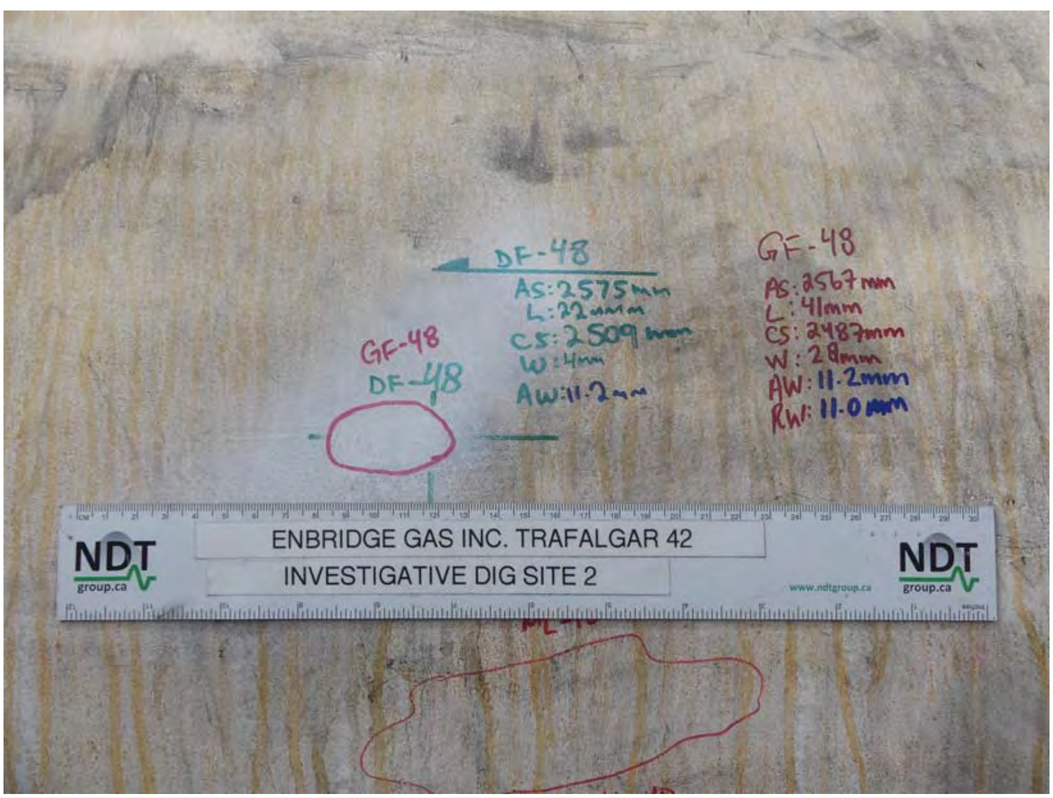
204 - GF-46

NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42

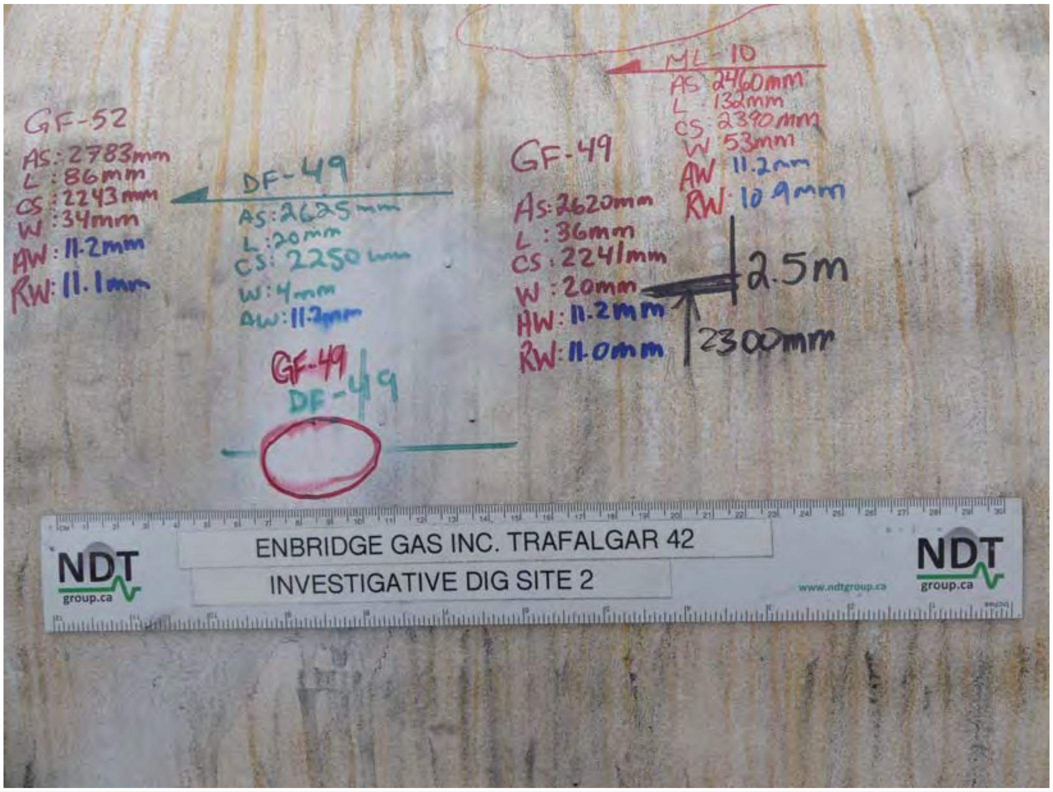


205 - GF-47

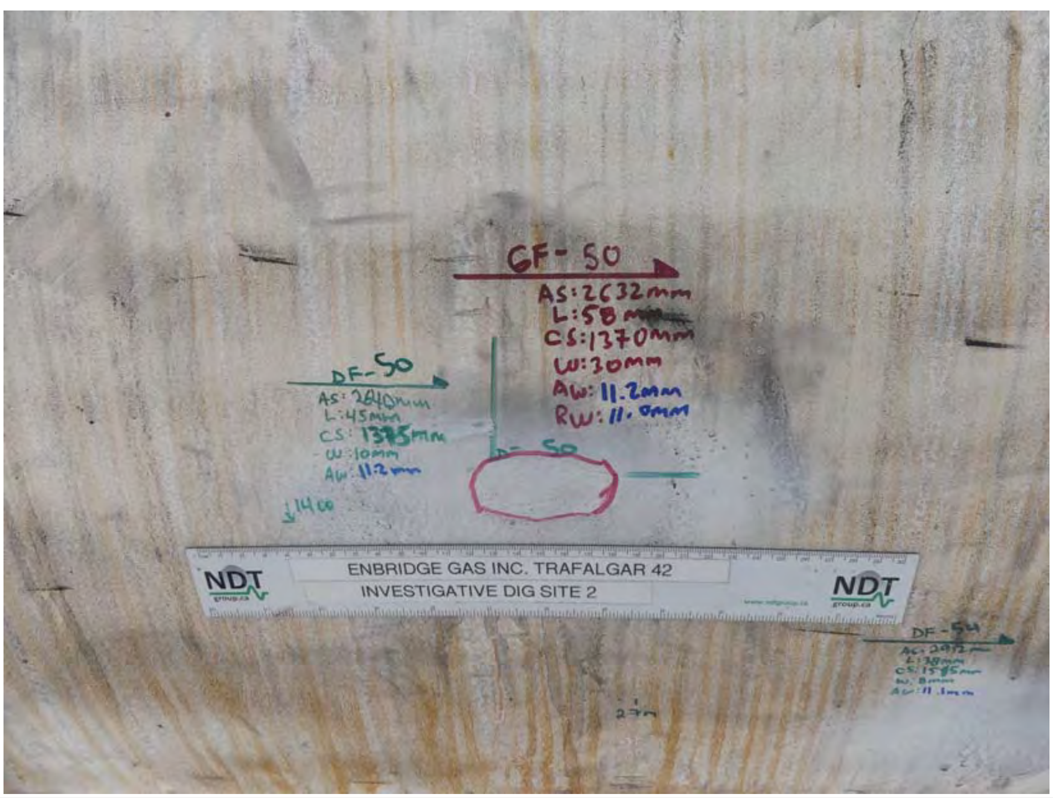


206 - GF-48

ENBRIDGE GAS INC. - TRAFALGAR NPS42

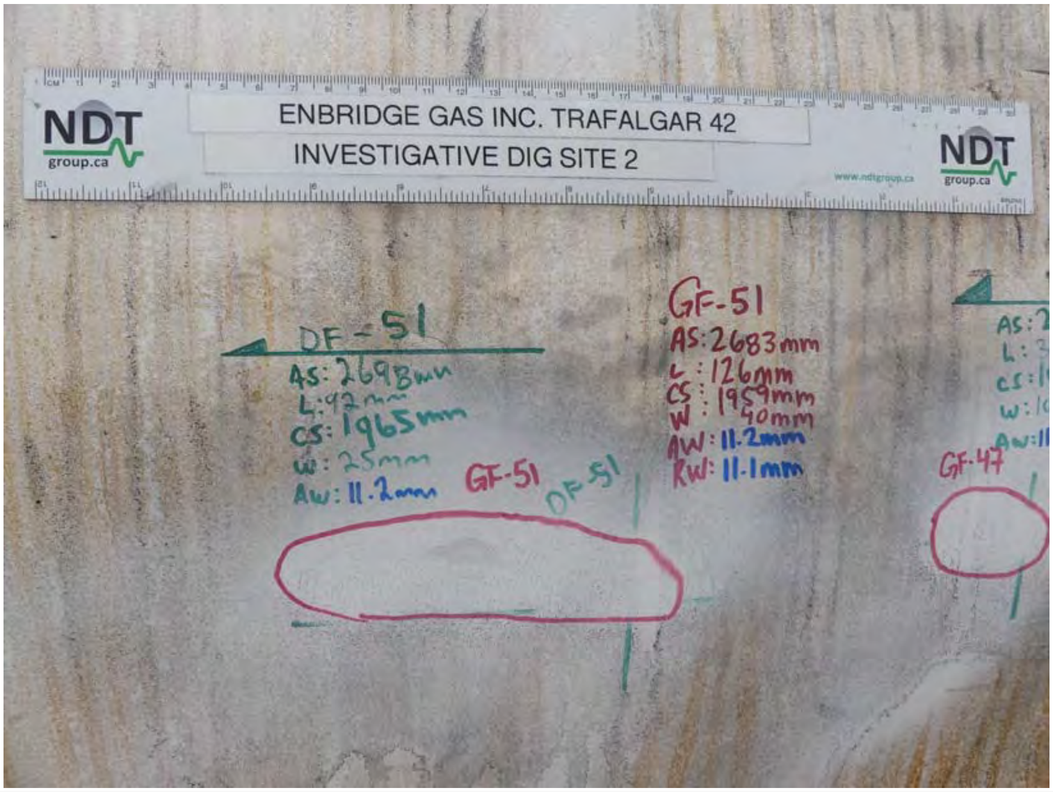


207 - GF-49

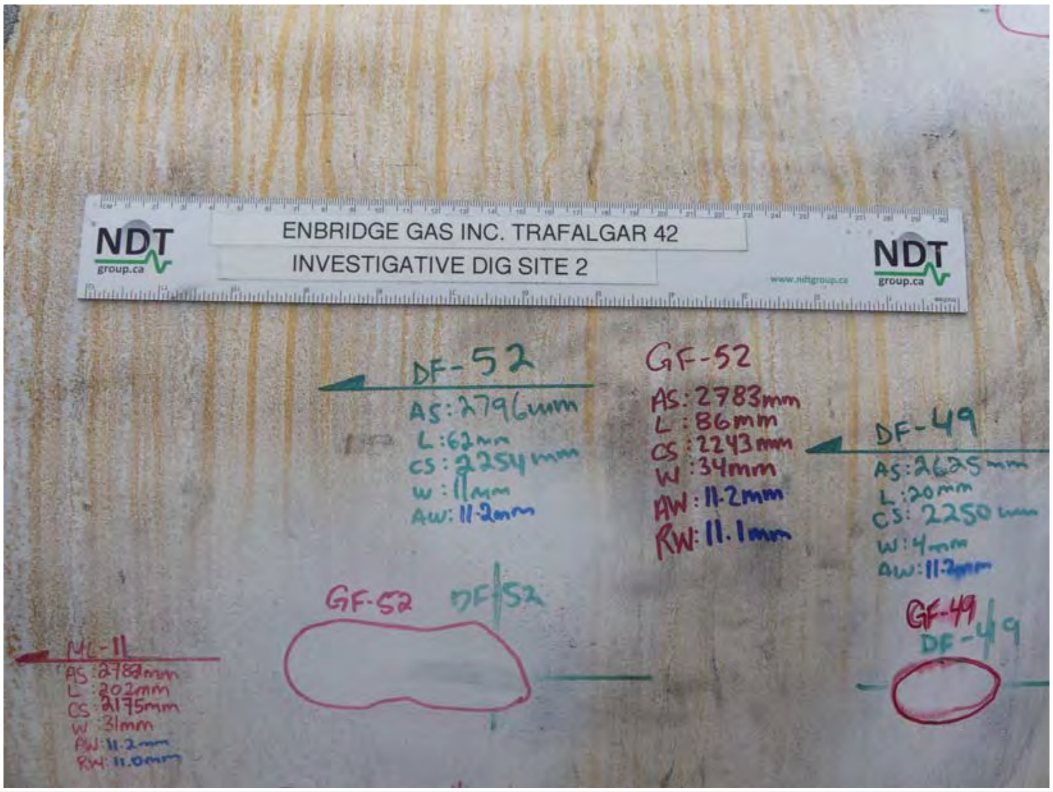


208 - GF-50

ENBRIDGE GAS INC. - TRAFALGAR NPS42

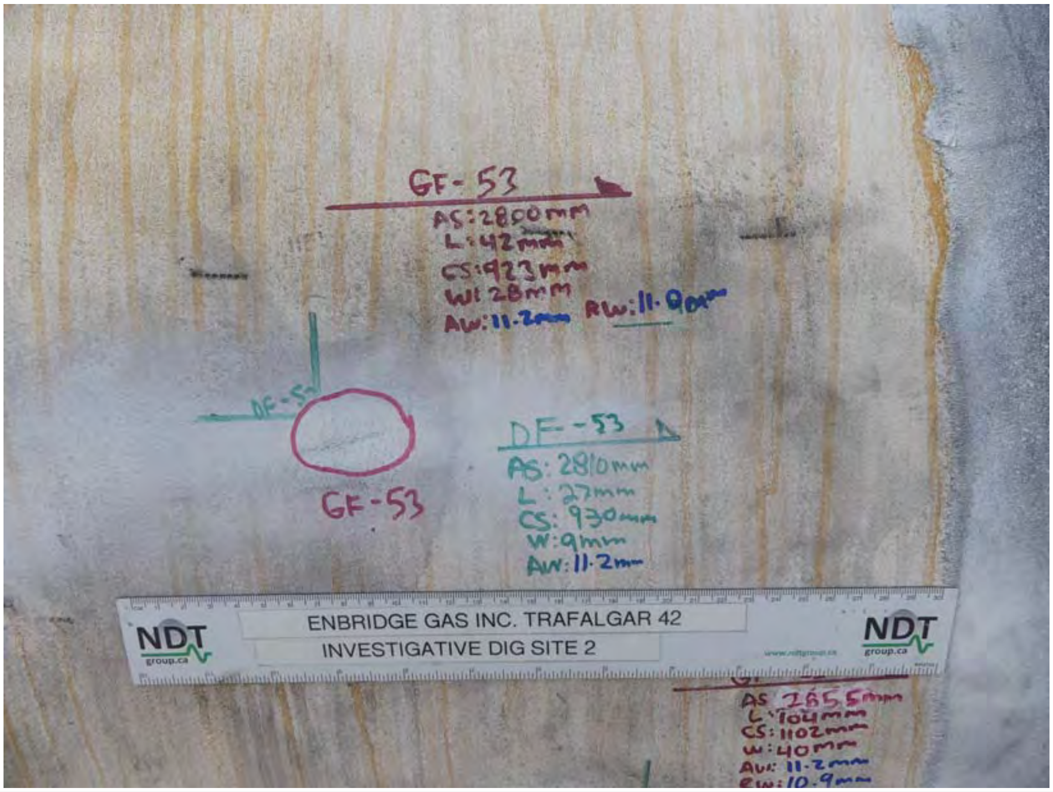


209 - GF-51

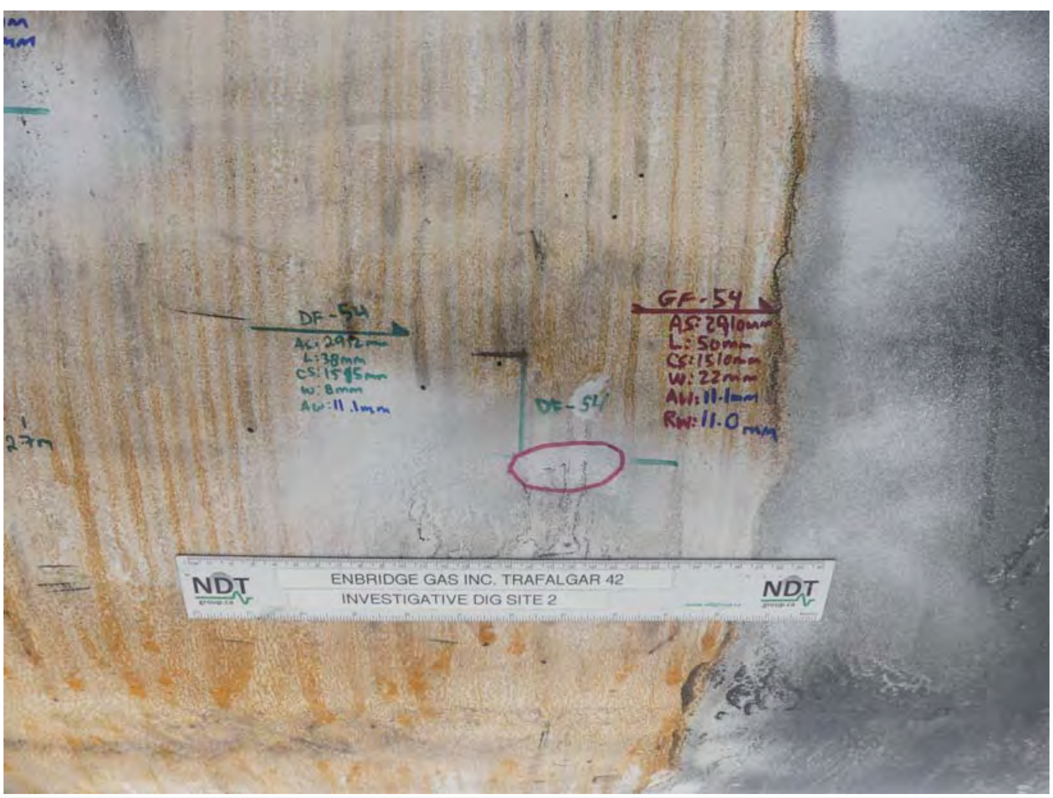


210 - GF-52

ENBRIDGE GAS INC. - TRAFALGAR NPS42



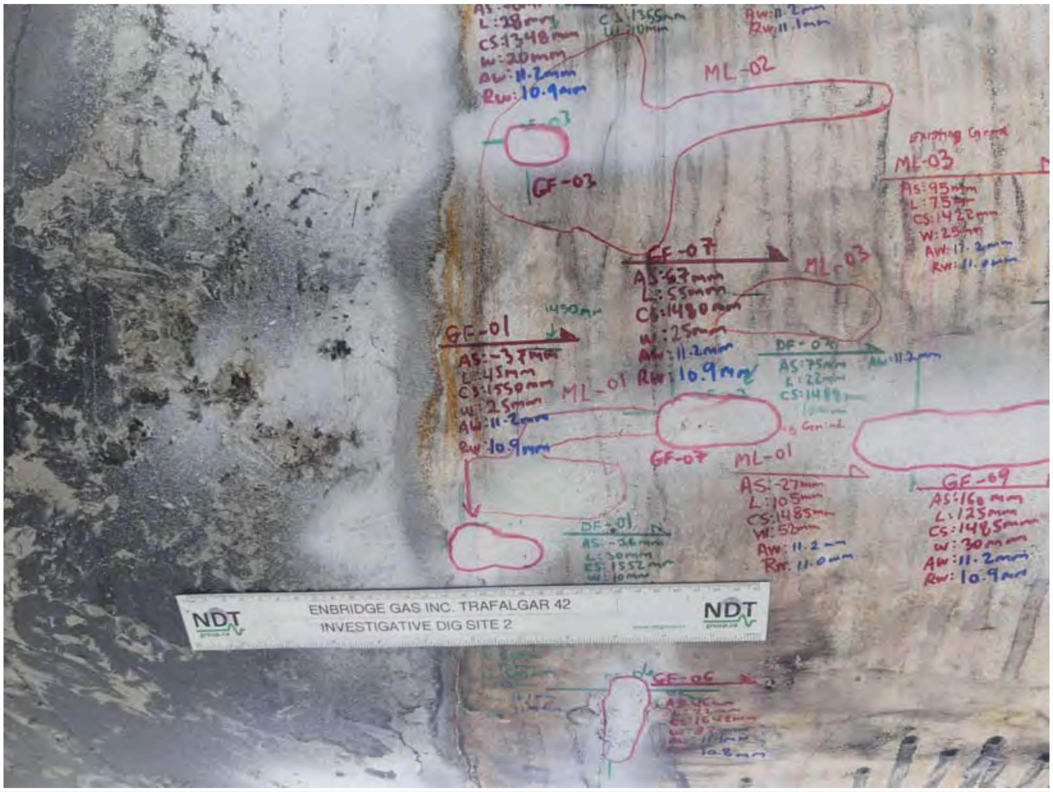
211 - GF-53



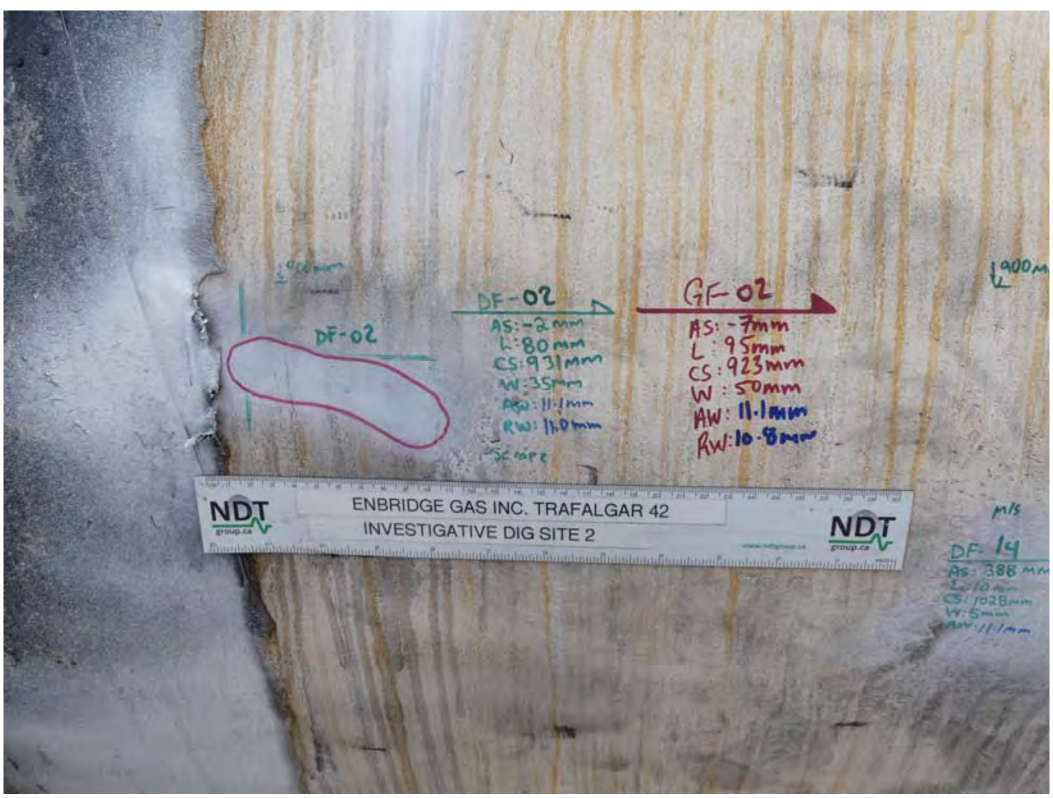
212 - GF-54

NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42

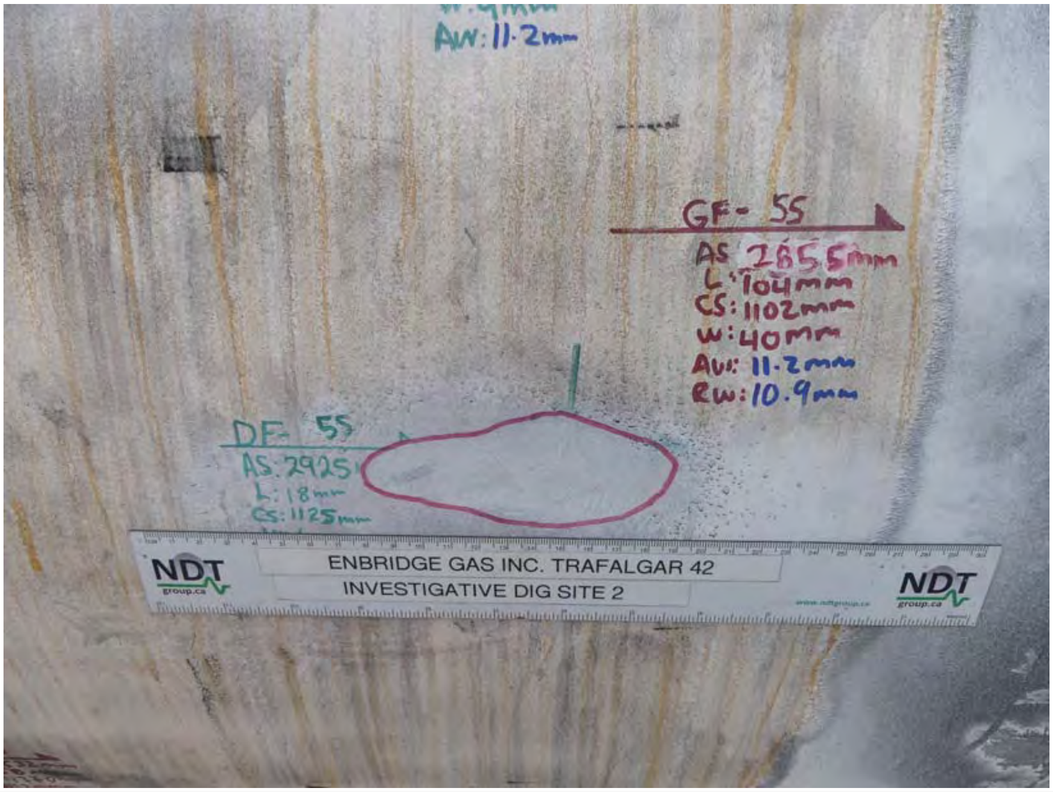


159 - GF-01

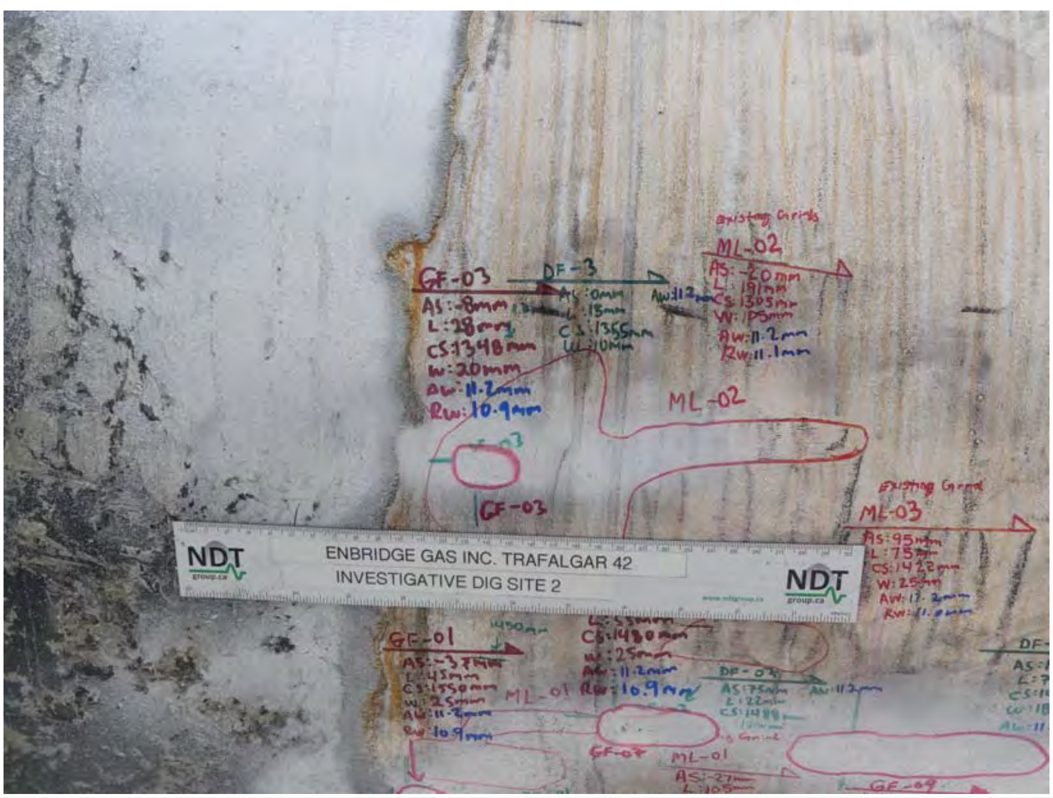


160 - GF-02

ENBRIDGE GAS INC. - TRAFALGAR NPS42

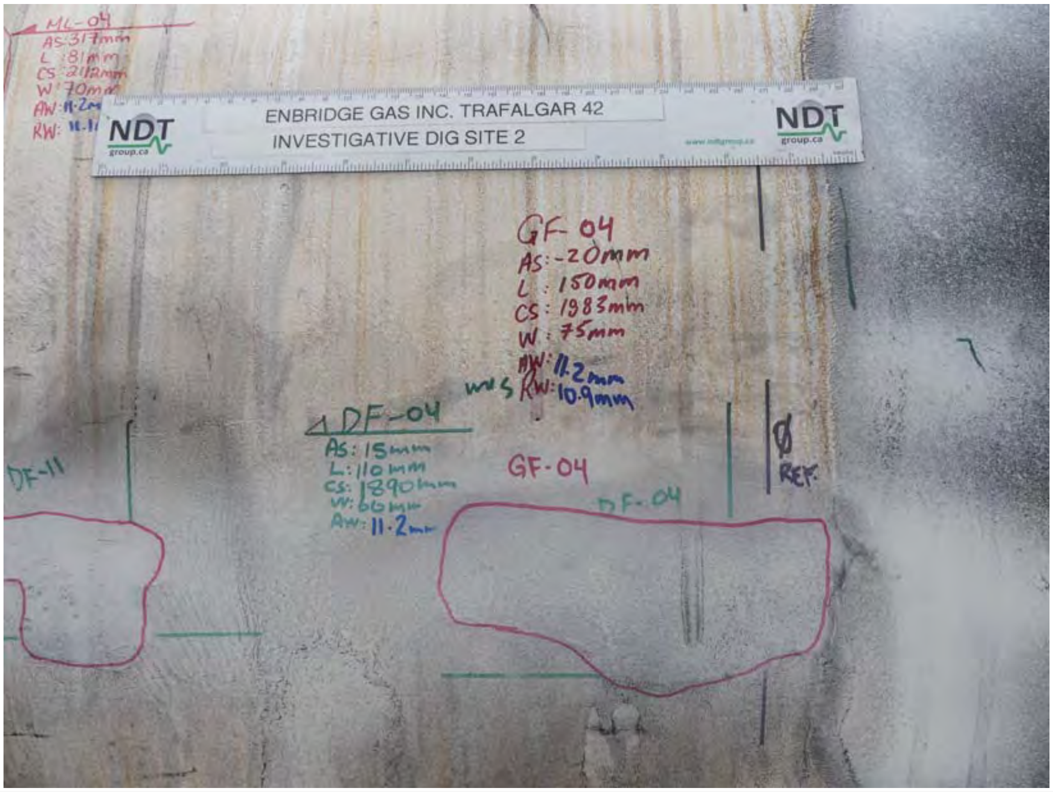


213 - GF-55

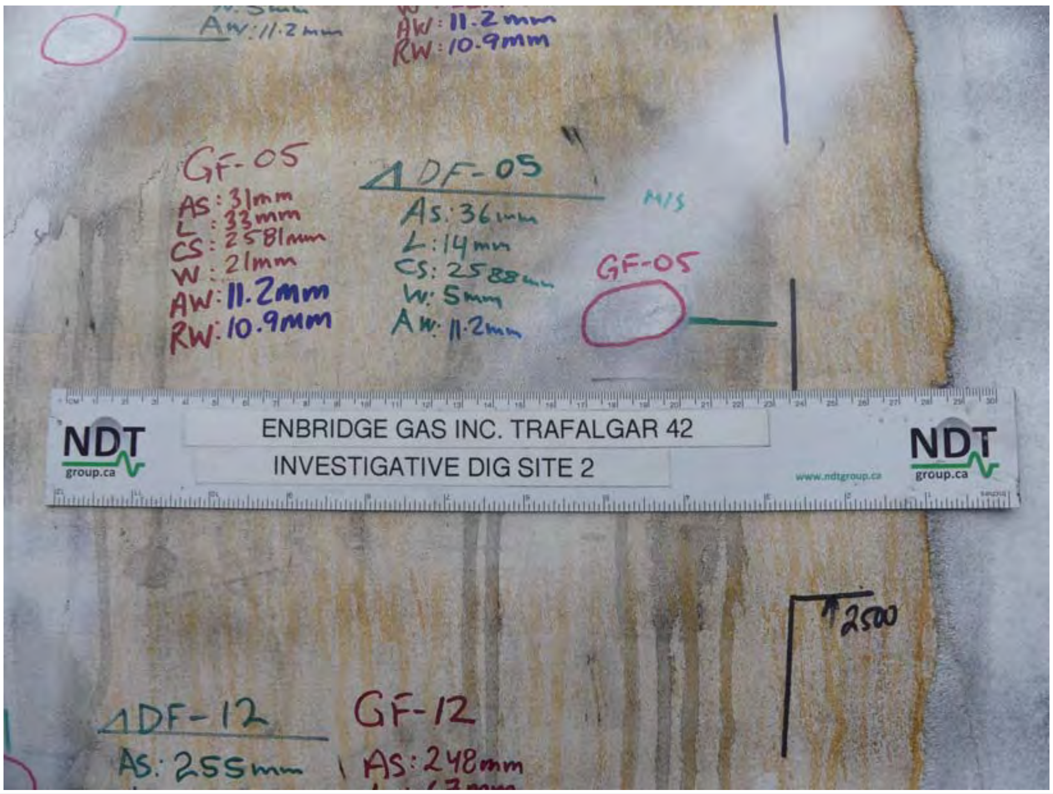


161 - GF-03

ENBRIDGE GAS INC. - TRAFALGAR NPS42

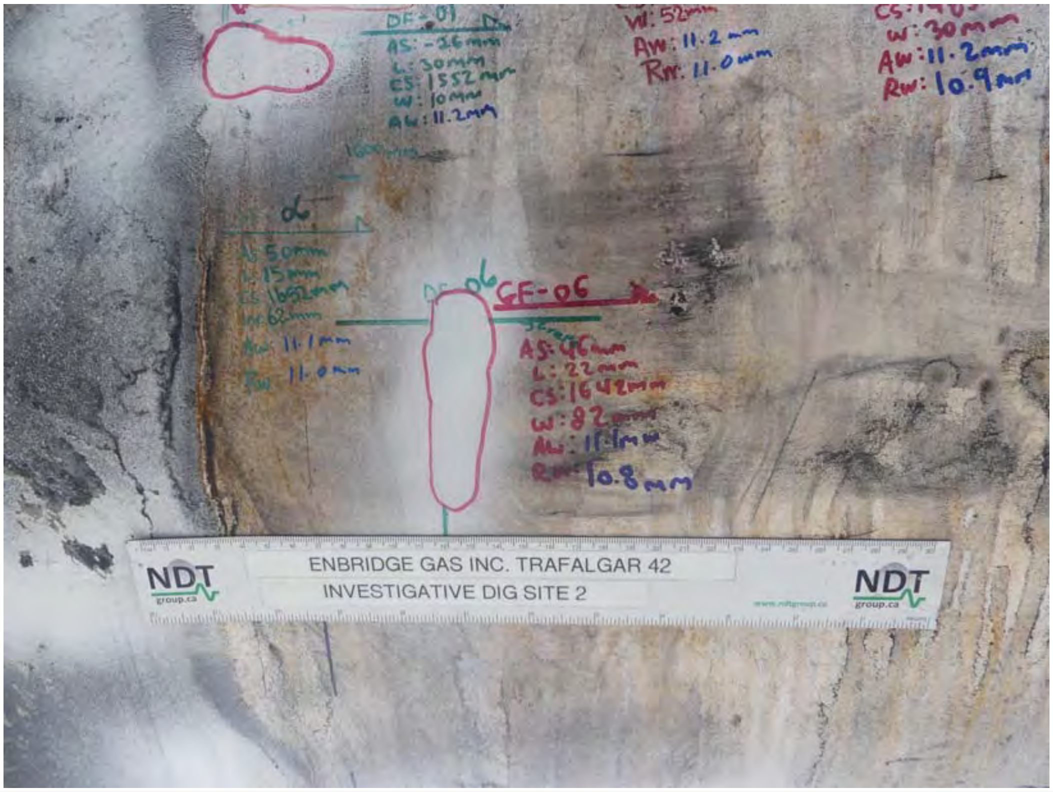


162 - GF-04

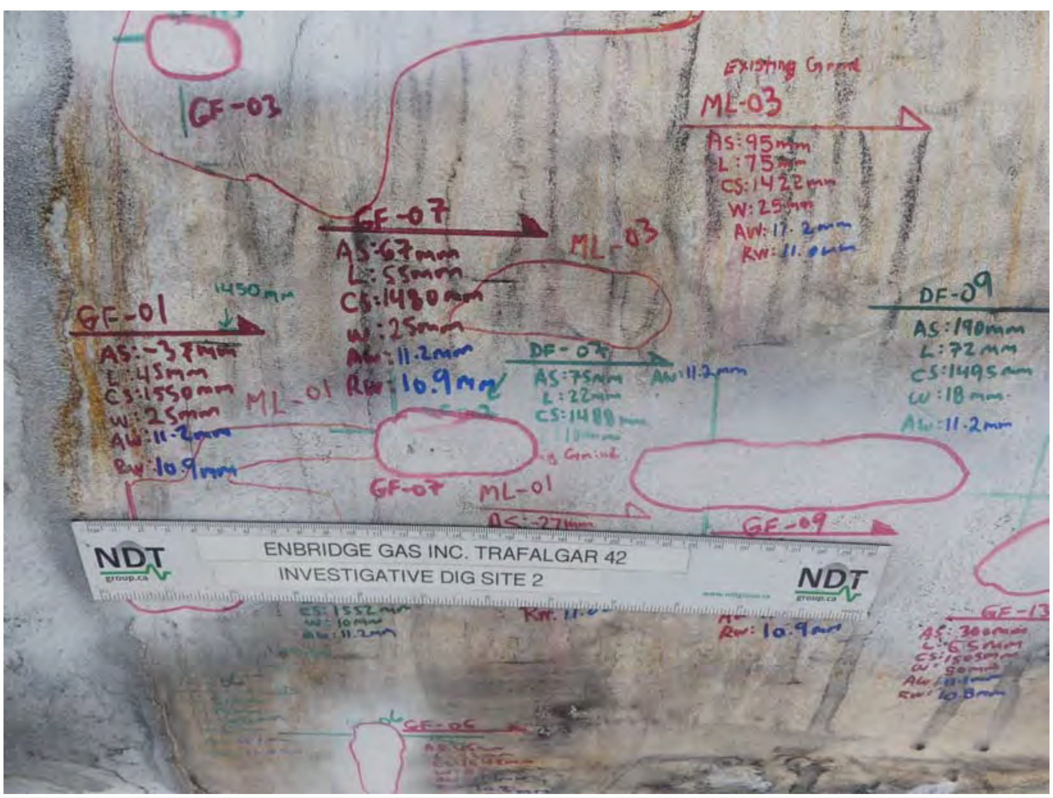


163 - GF-05

ENBRIDGE GAS INC. - TRAFALGAR NPS42

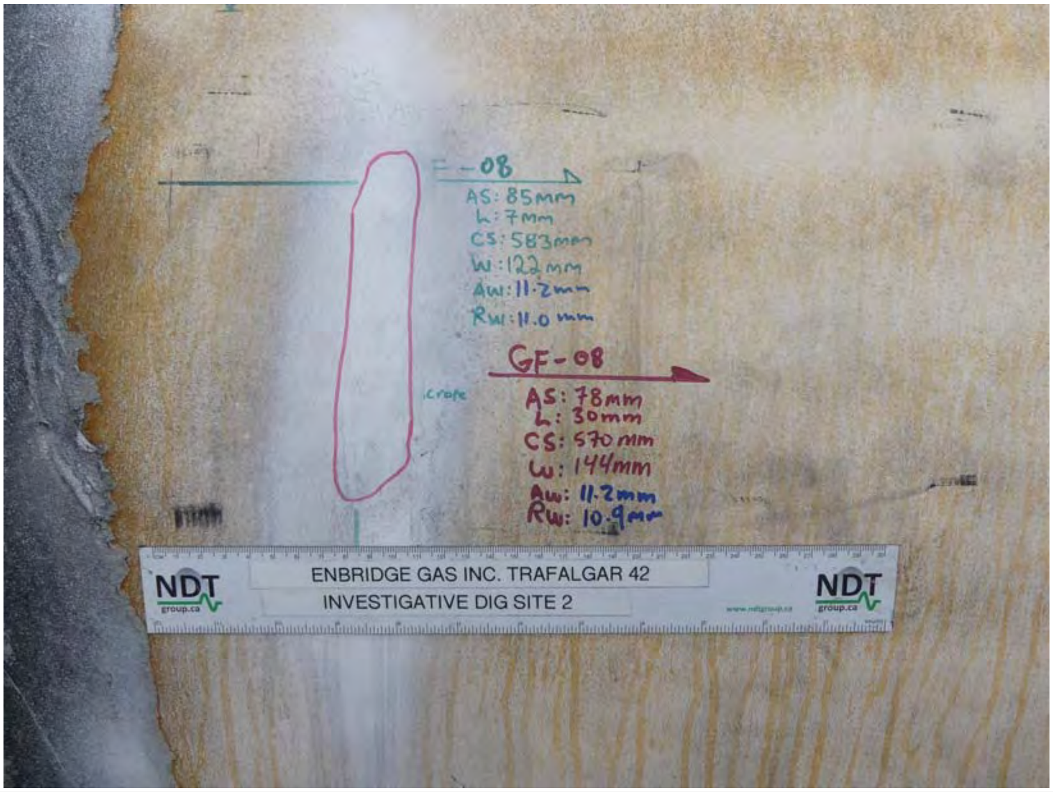


164 - GF-06

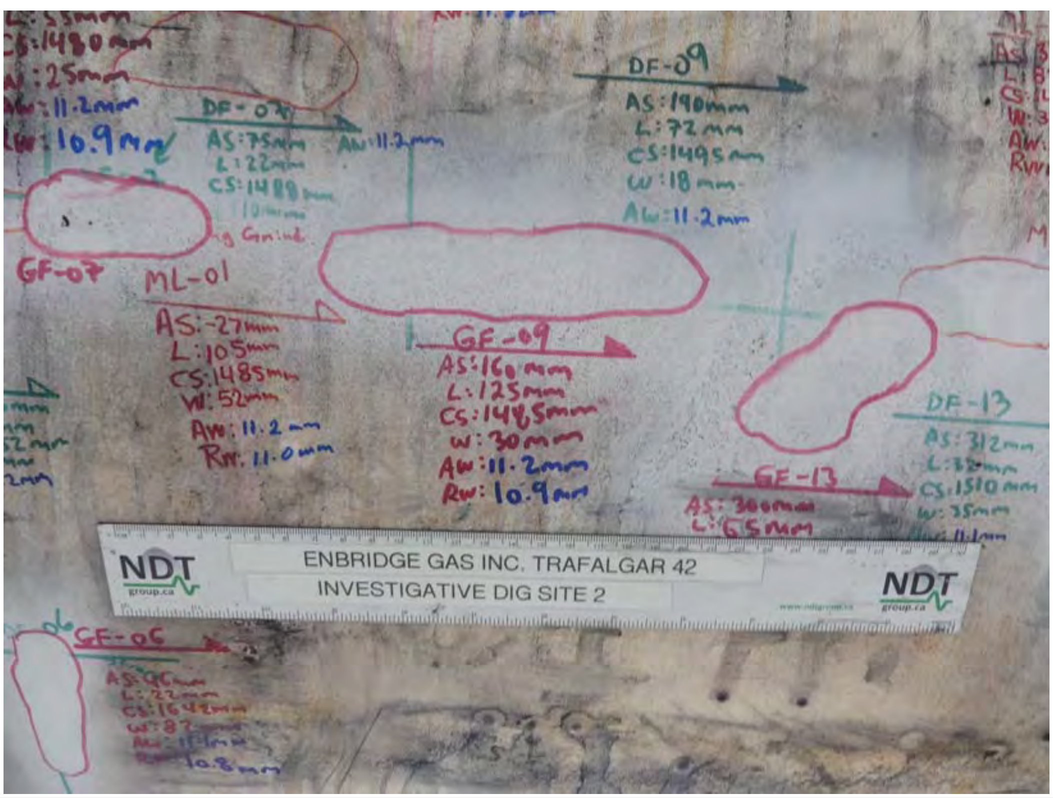


165 - GF-07

ENBRIDGE GAS INC. - TRAFALGAR NPS42

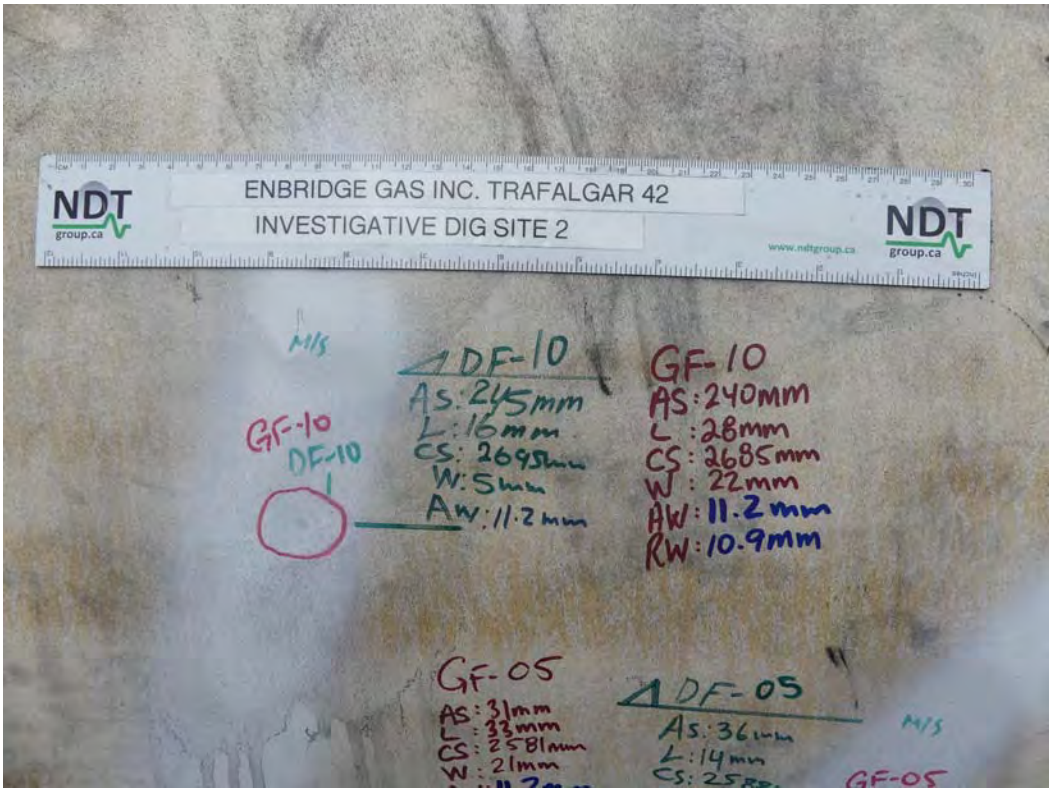


166 - GF-08

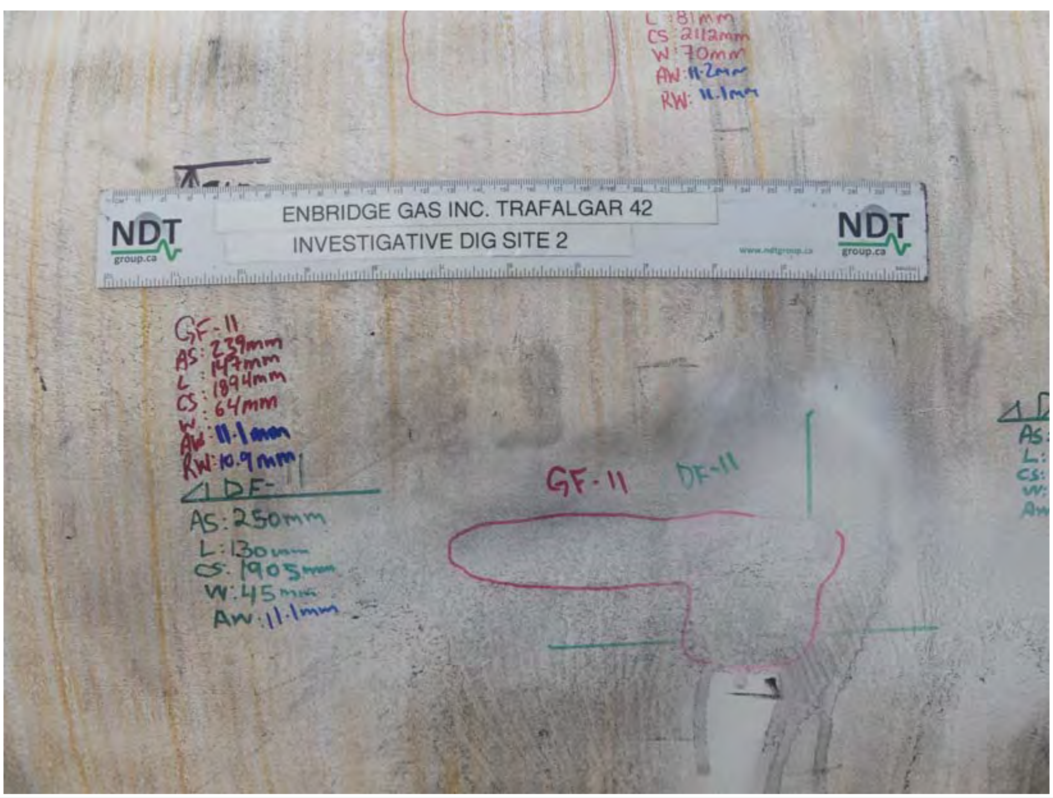


167 - GF-09

ENBRIDGE GAS INC. - TRAFALGAR NPS42

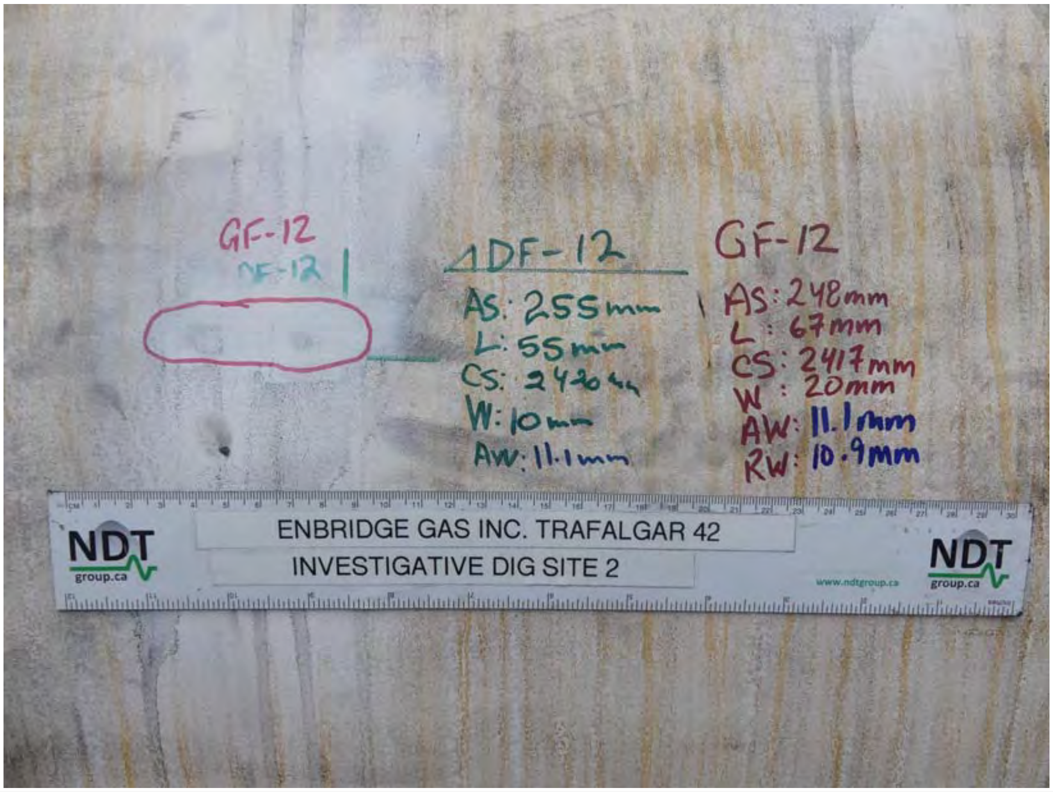


168 - GF-10

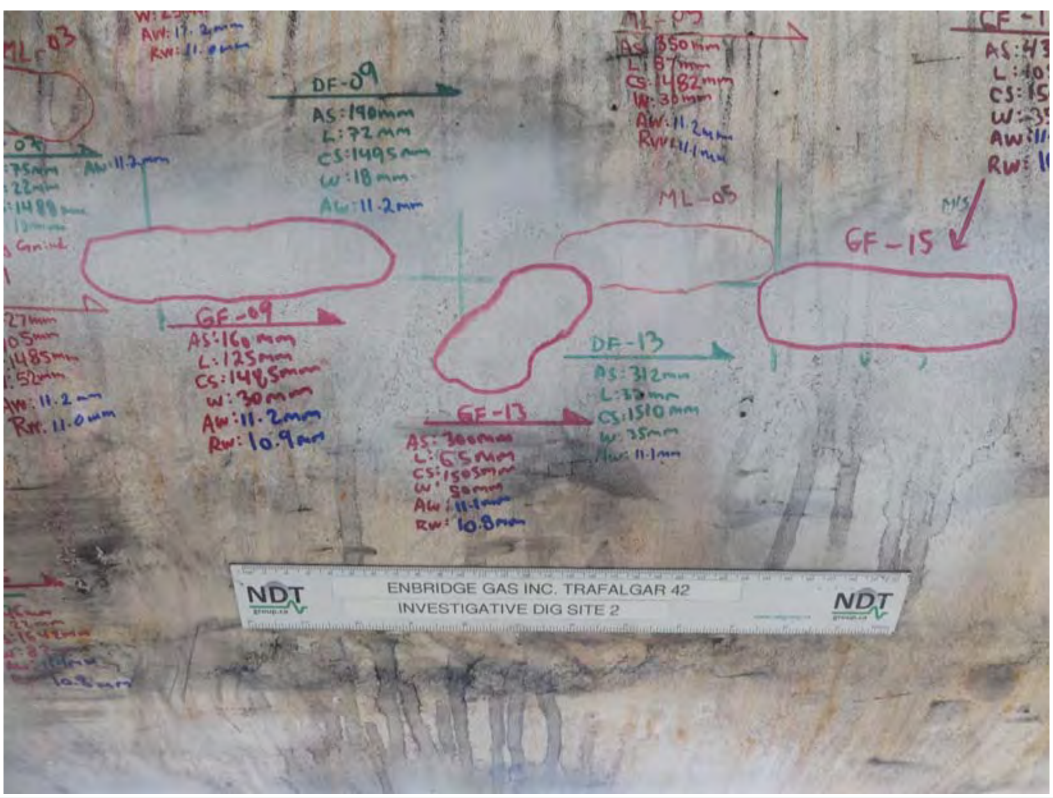


169 - GF-11

ENBRIDGE GAS INC. - TRAFALGAR NPS42



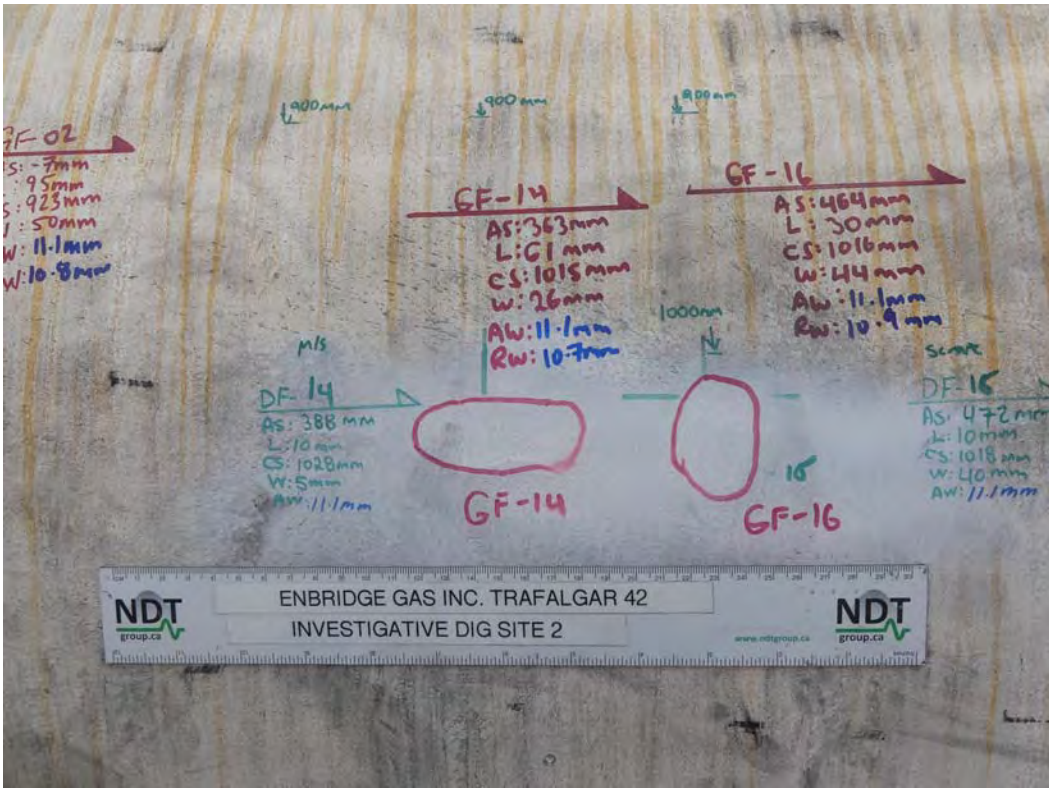
170 - GF-12



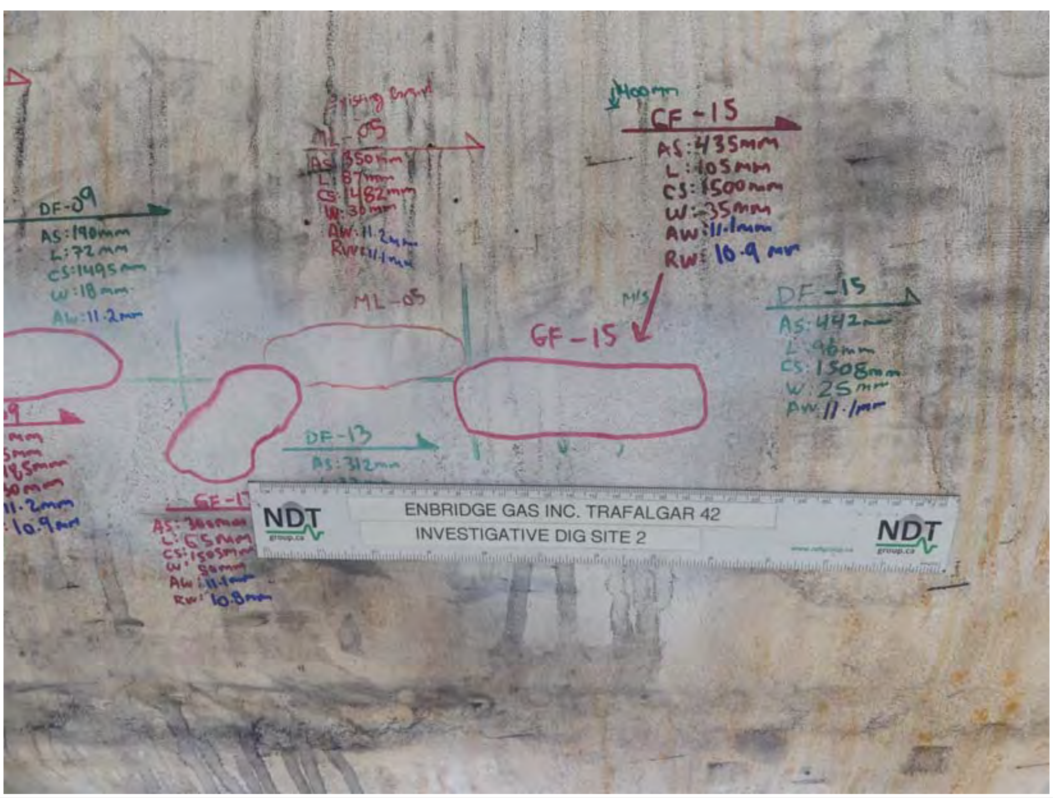
171 - GF-13

NDT group.ca

ENBRIDGE GAS INC. - TRAFALGAR NPS42

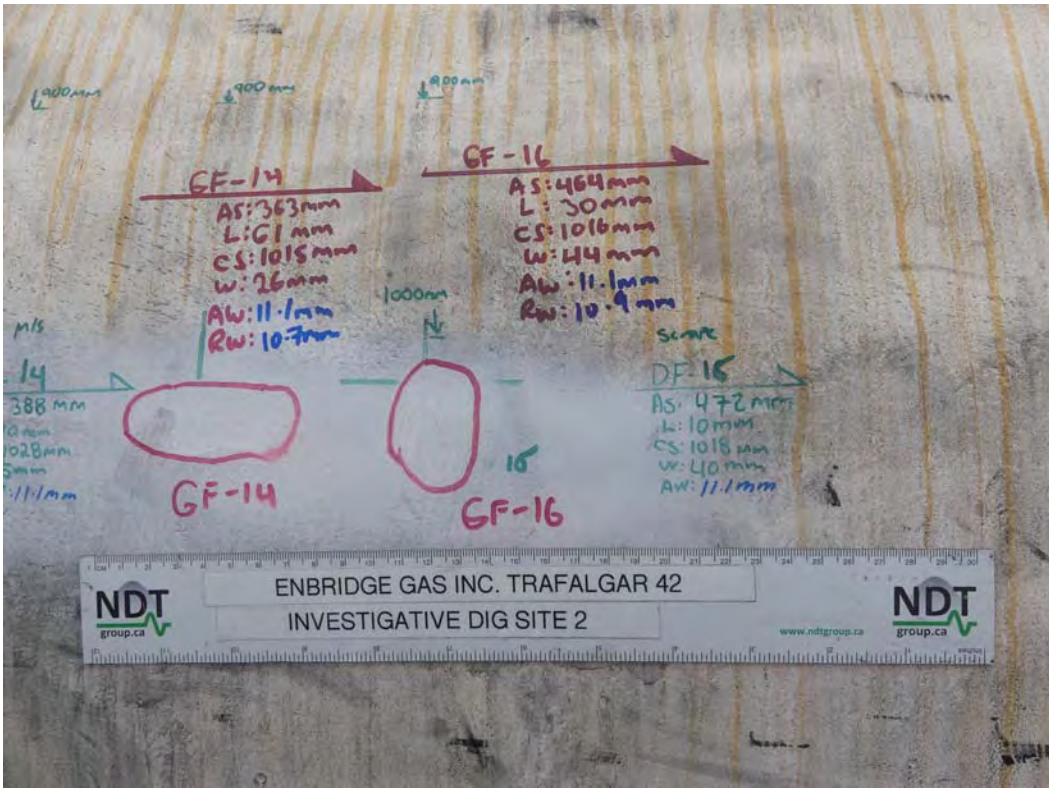


172 - GF-14

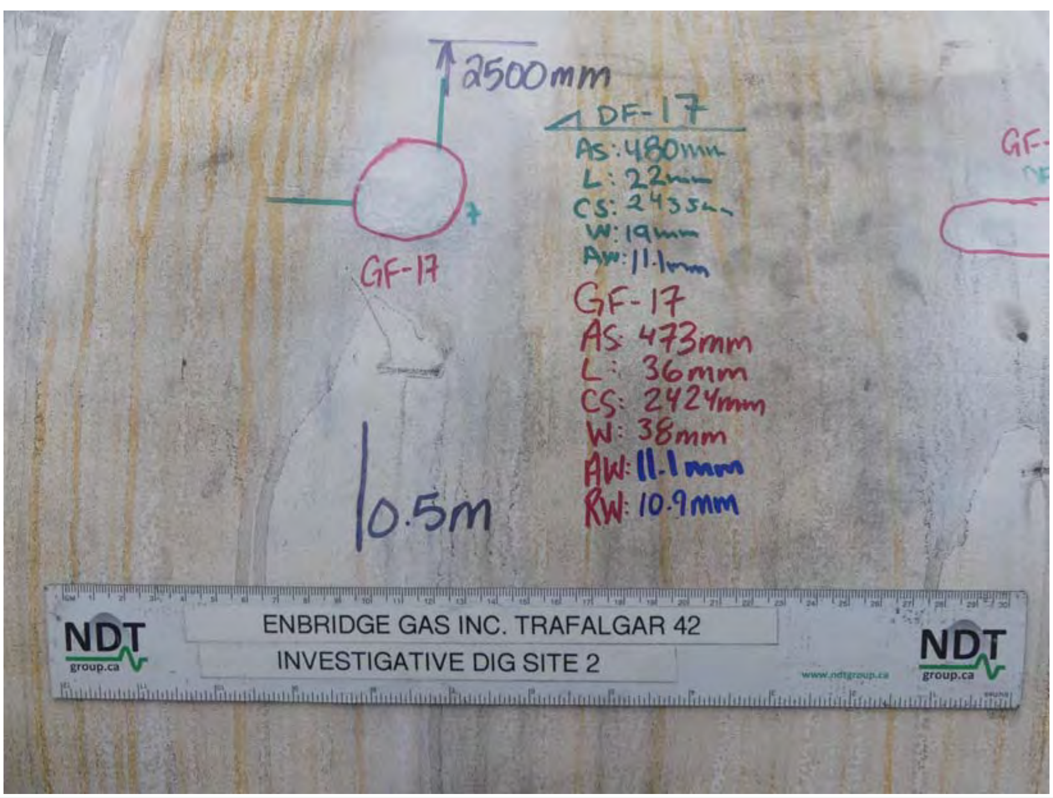


173 - GF-15

ENBRIDGE GAS INC. - TRAFALGAR NPS42

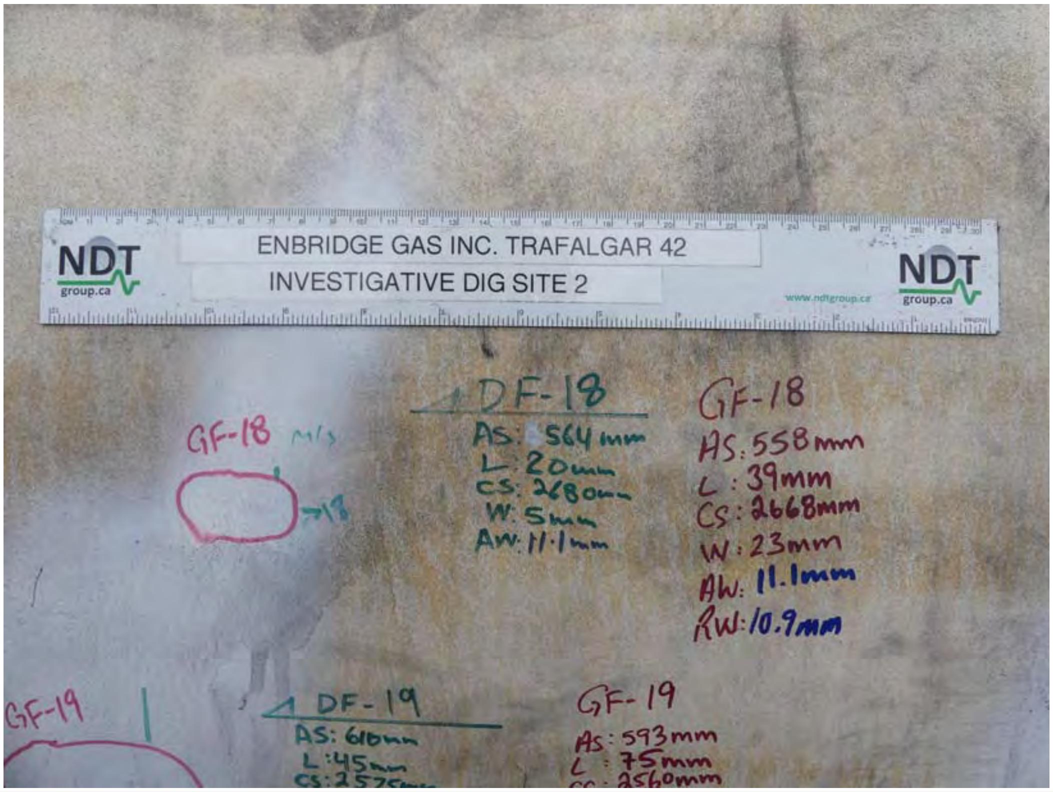


174 - GF-16

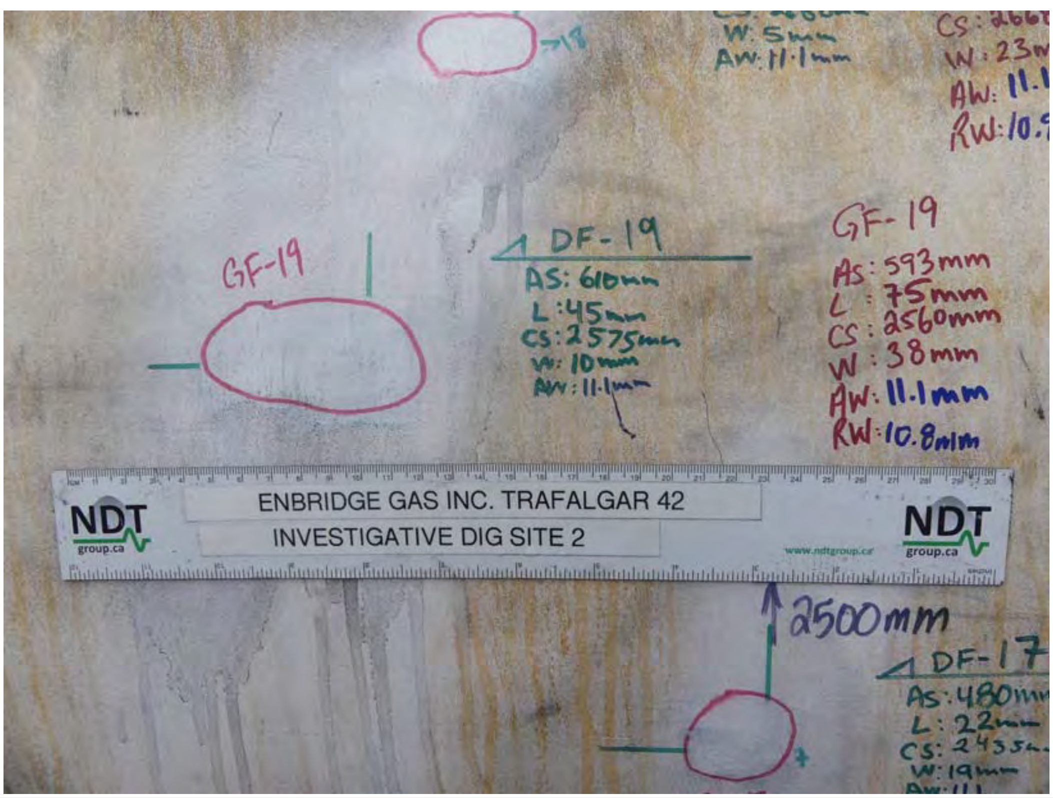


175 - GF-17

ENBRIDGE GAS INC. - TRAFALGAR NPS42

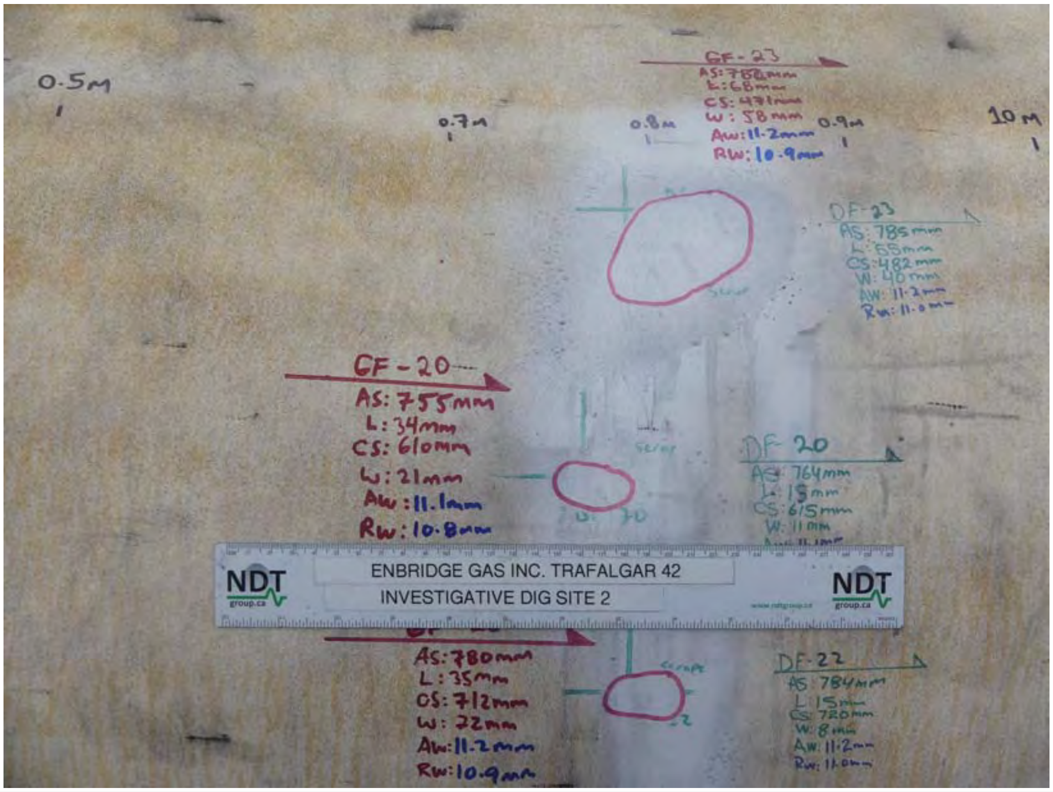


176 - GF-18

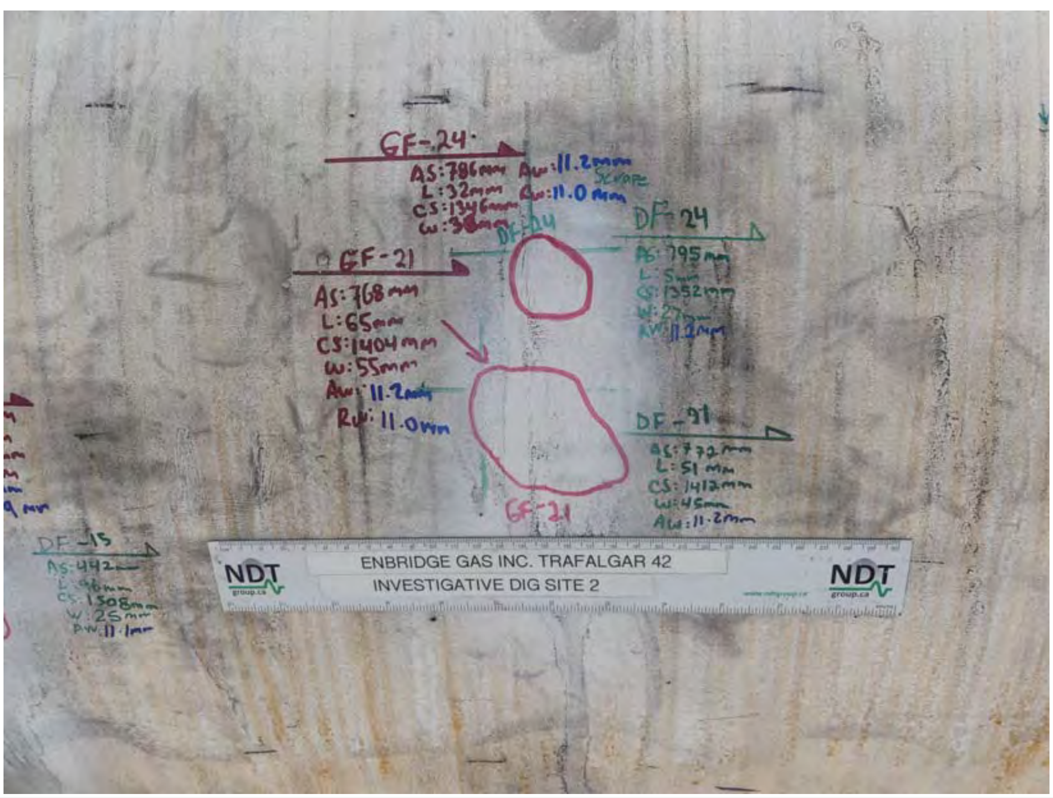


177 - GF-19

ENBRIDGE GAS INC. - TRAFALGAR NPS42

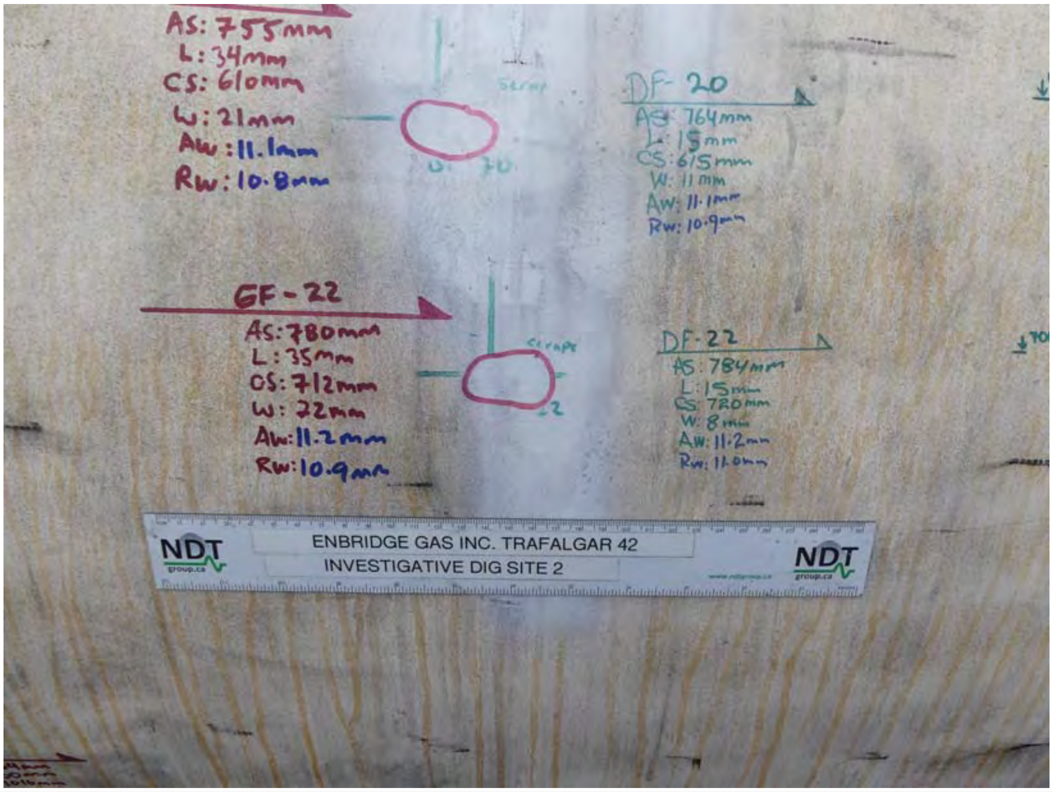


178 - GF-20

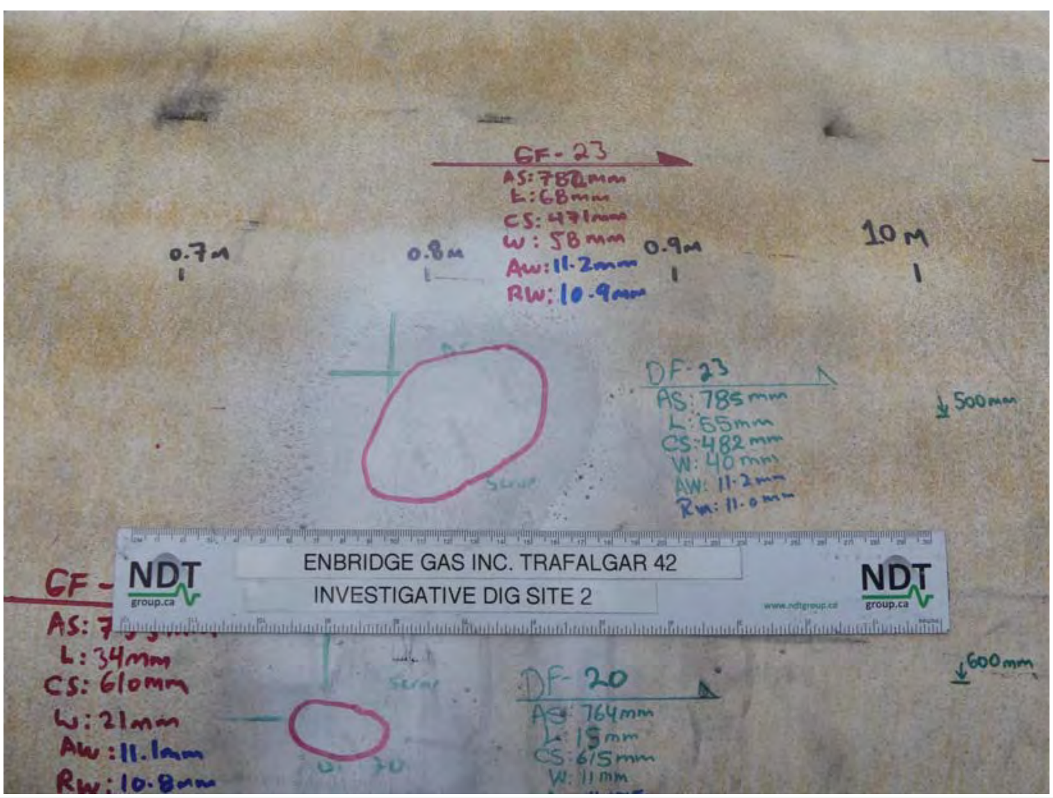


179 - GF-21

ENBRIDGE GAS INC. - TRAFALGAR NPS42

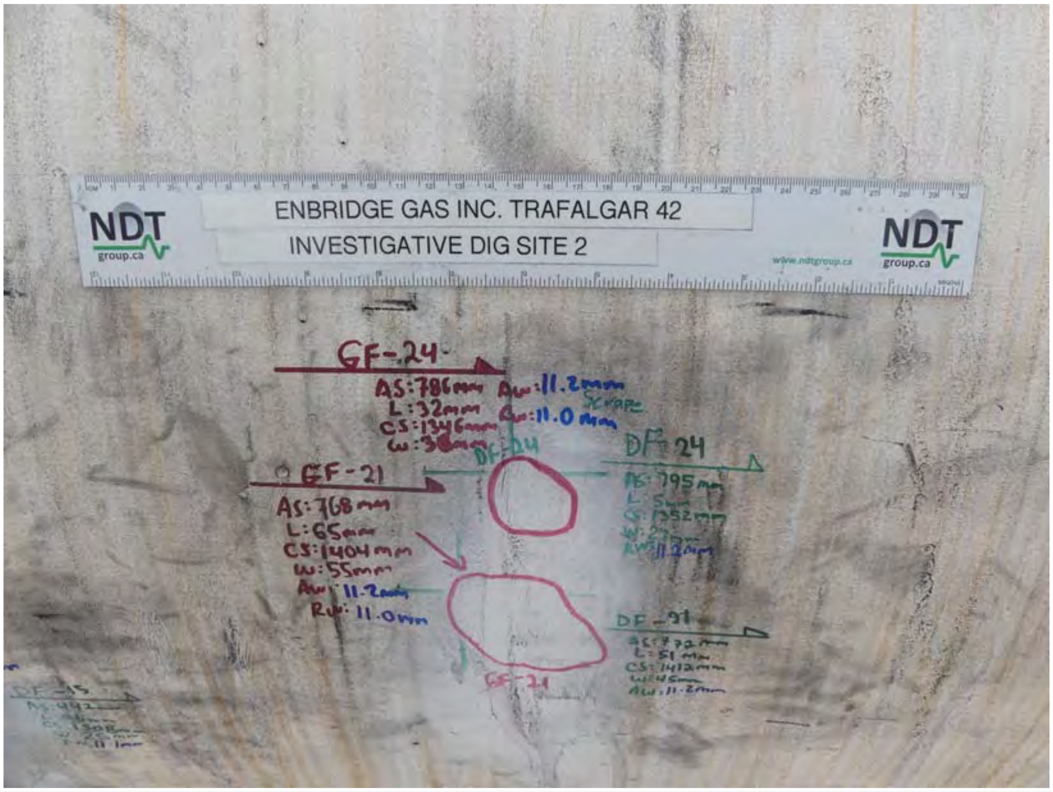


180 - GF-22

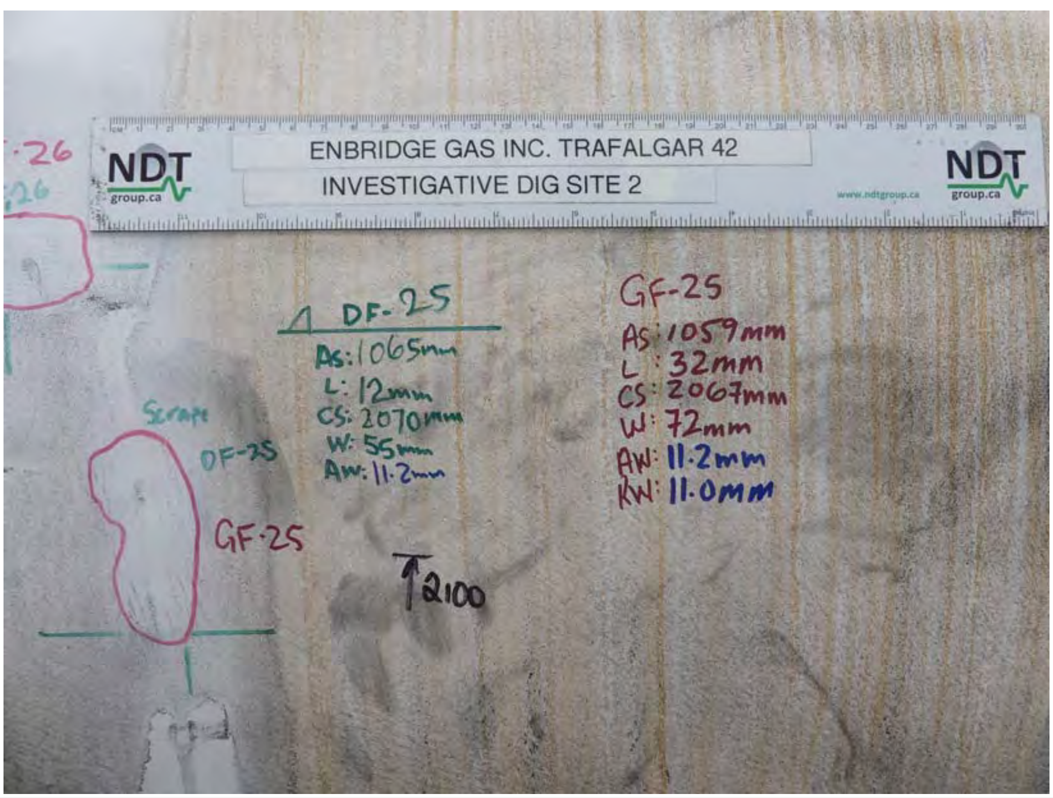


181 - GF-23

ENBRIDGE GAS INC. - TRAFALGAR NPS42

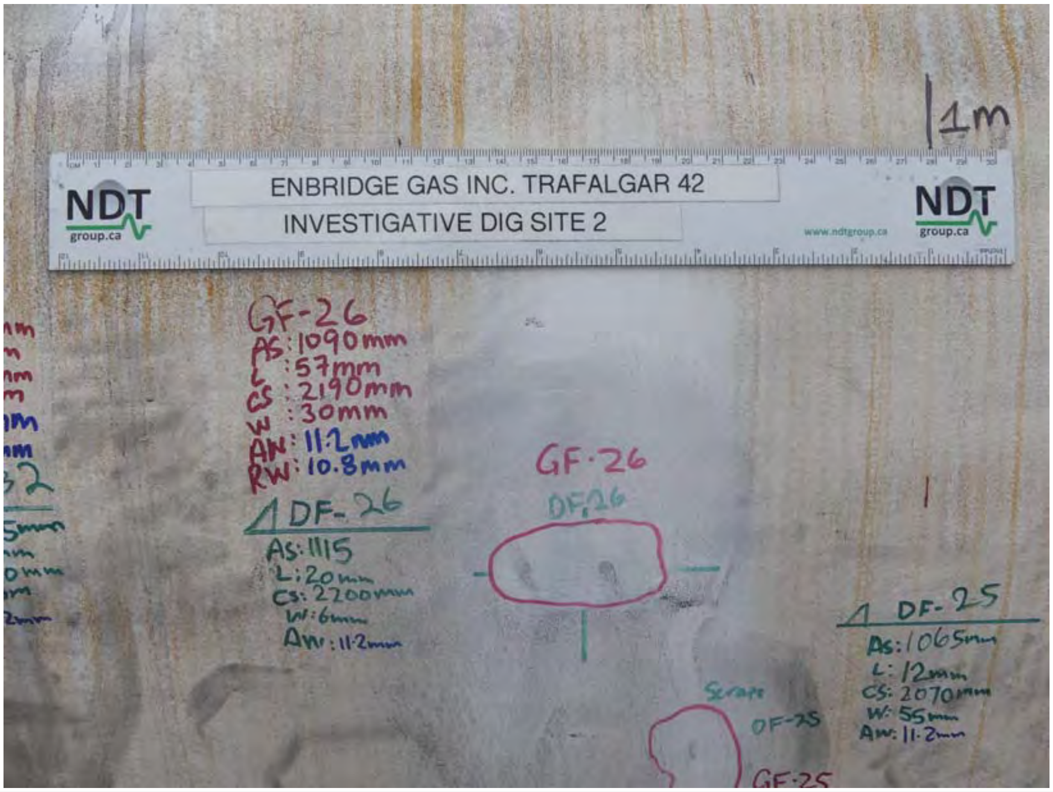


182 - GF-24

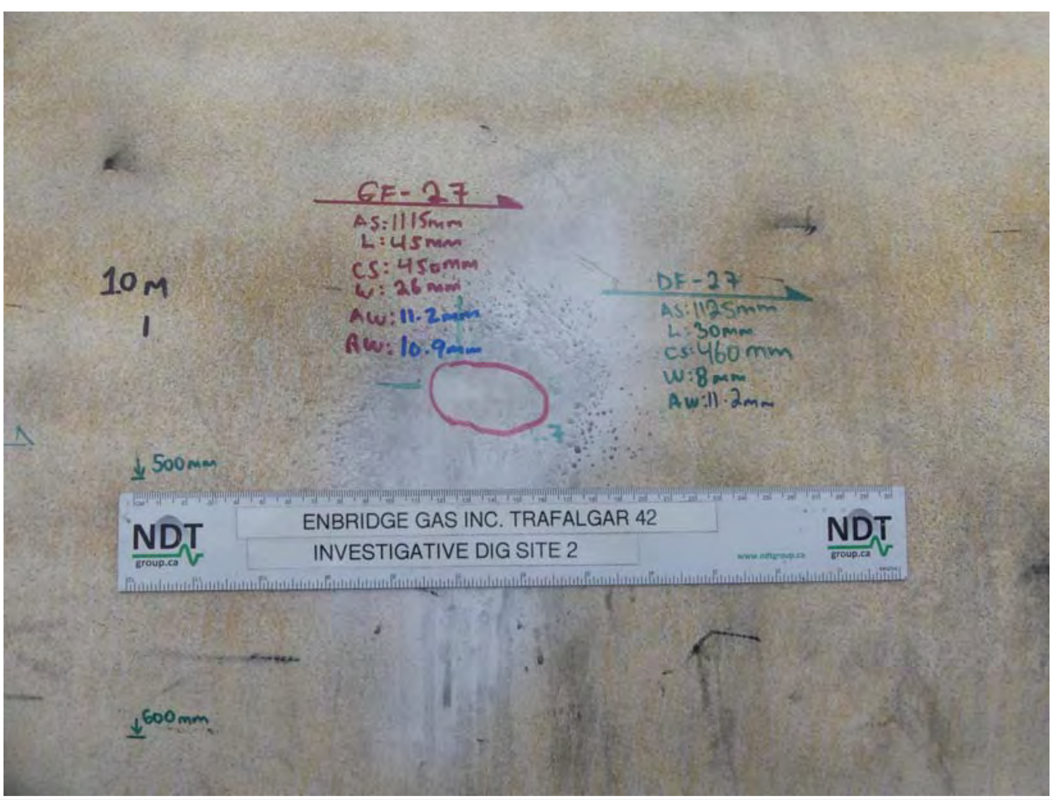


183 - GF-25

ENBRIDGE GAS INC. - TRAFALGAR NPS42

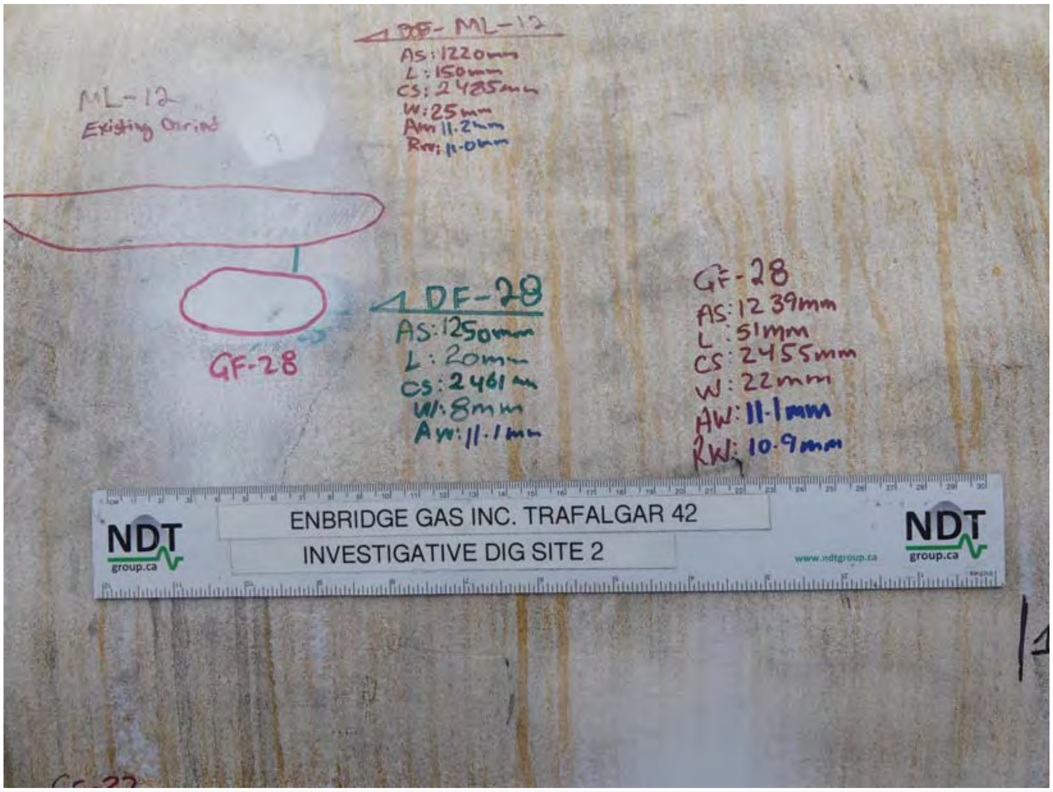


184 - GF-26

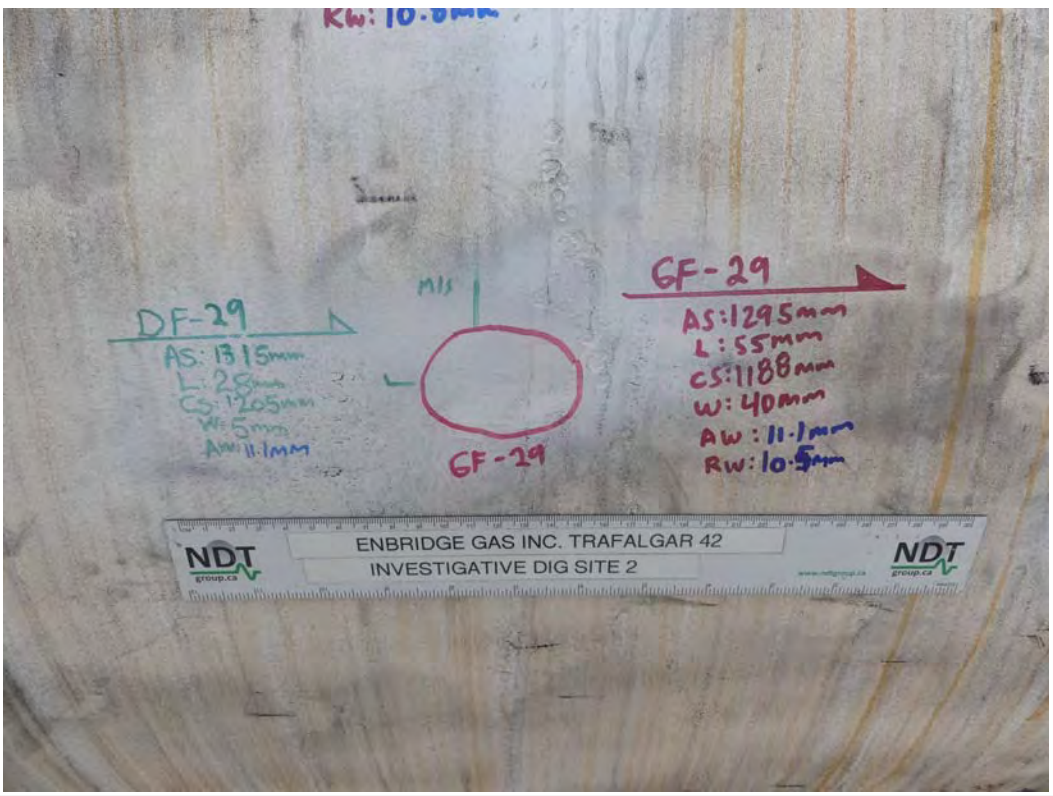


185 - GF-27

ENBRIDGE GAS INC. - TRAFALGAR NPS42

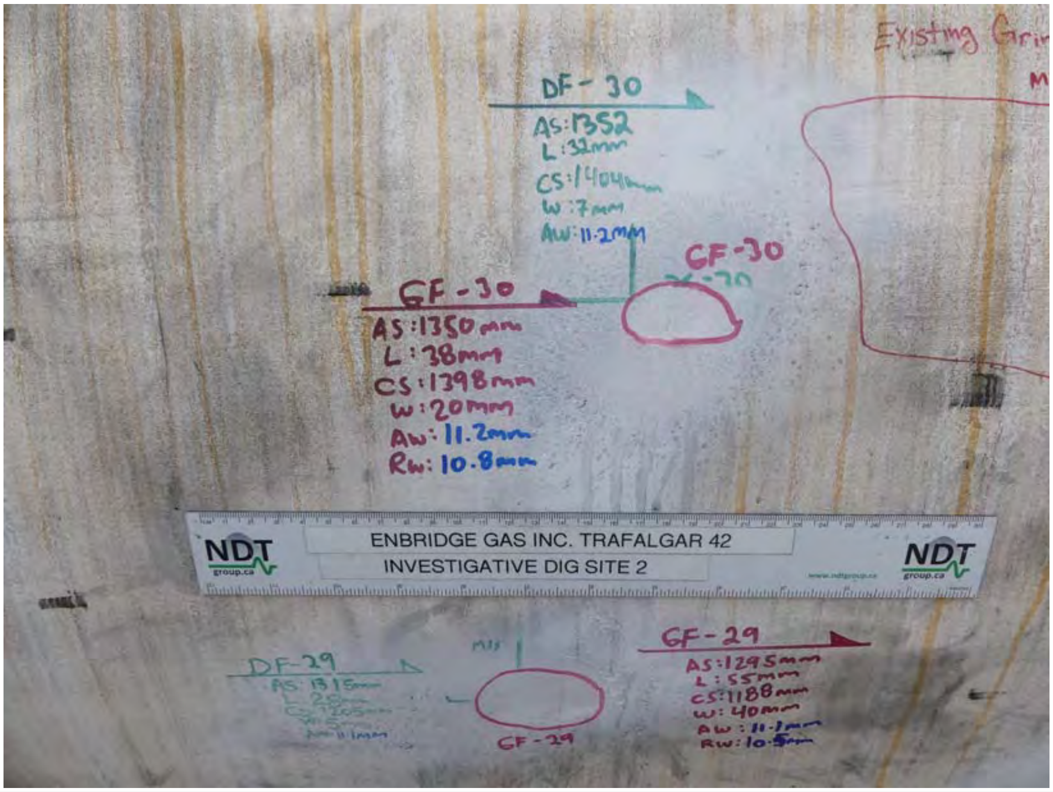


186 - GF-28

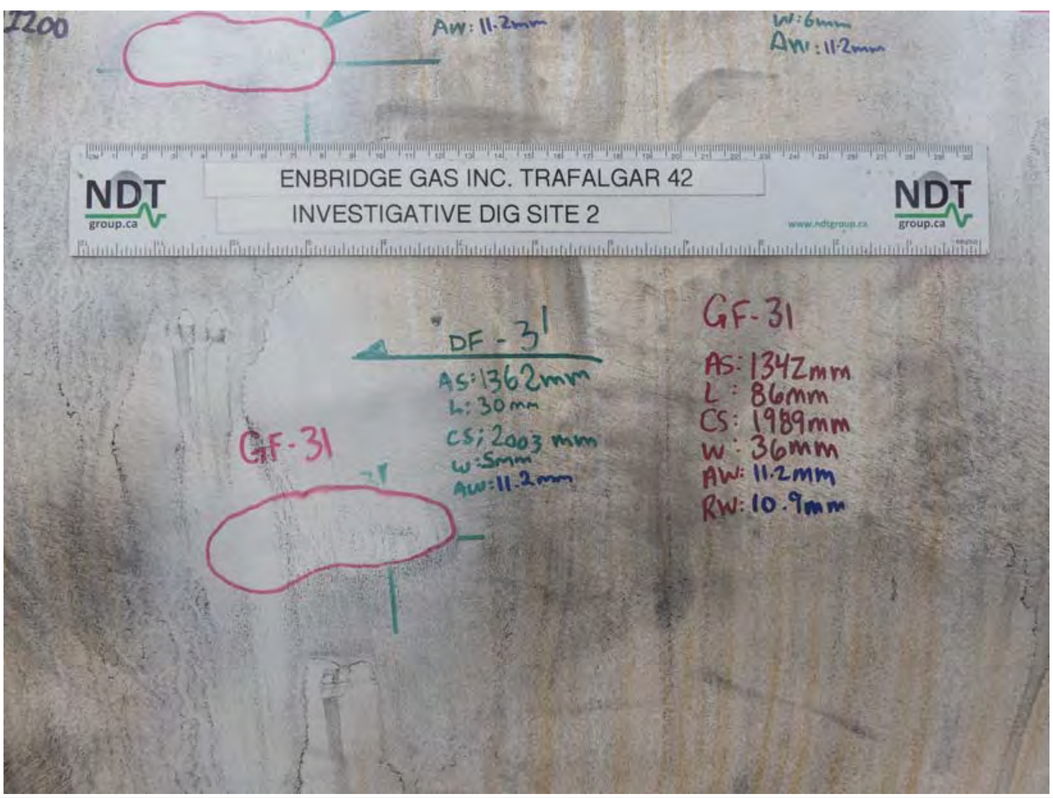


187 - GF-29

ENBRIDGE GAS INC. - TRAFALGAR NPS42

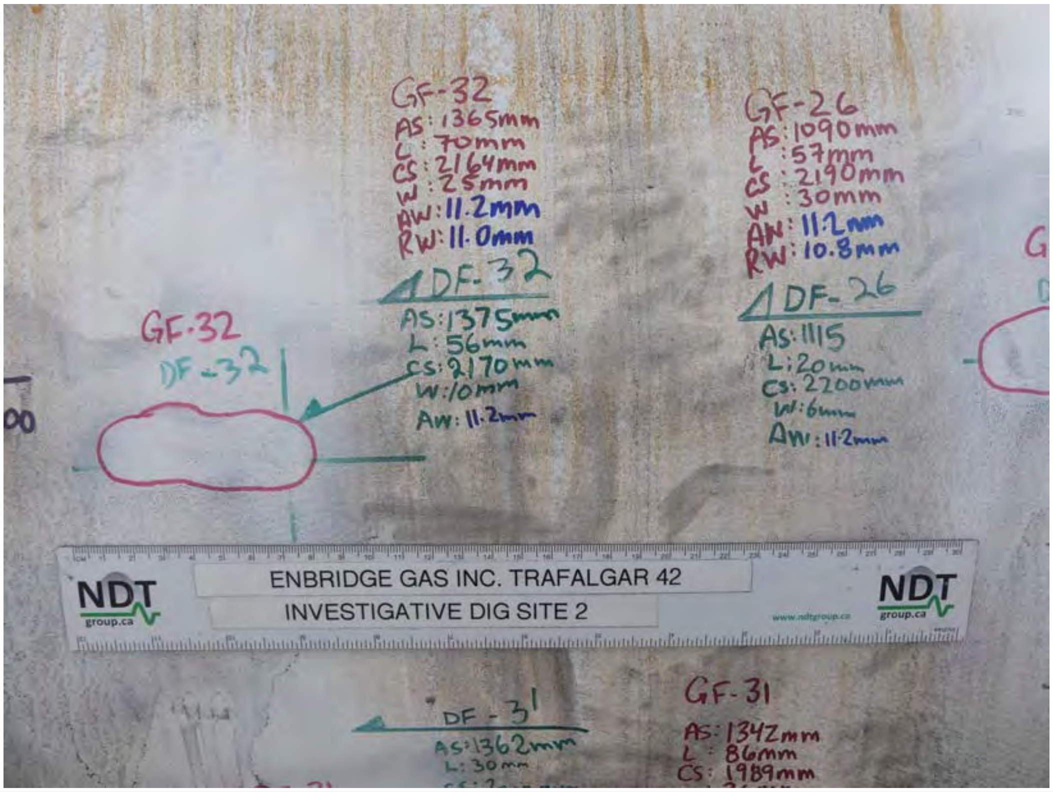


188 - GF-30

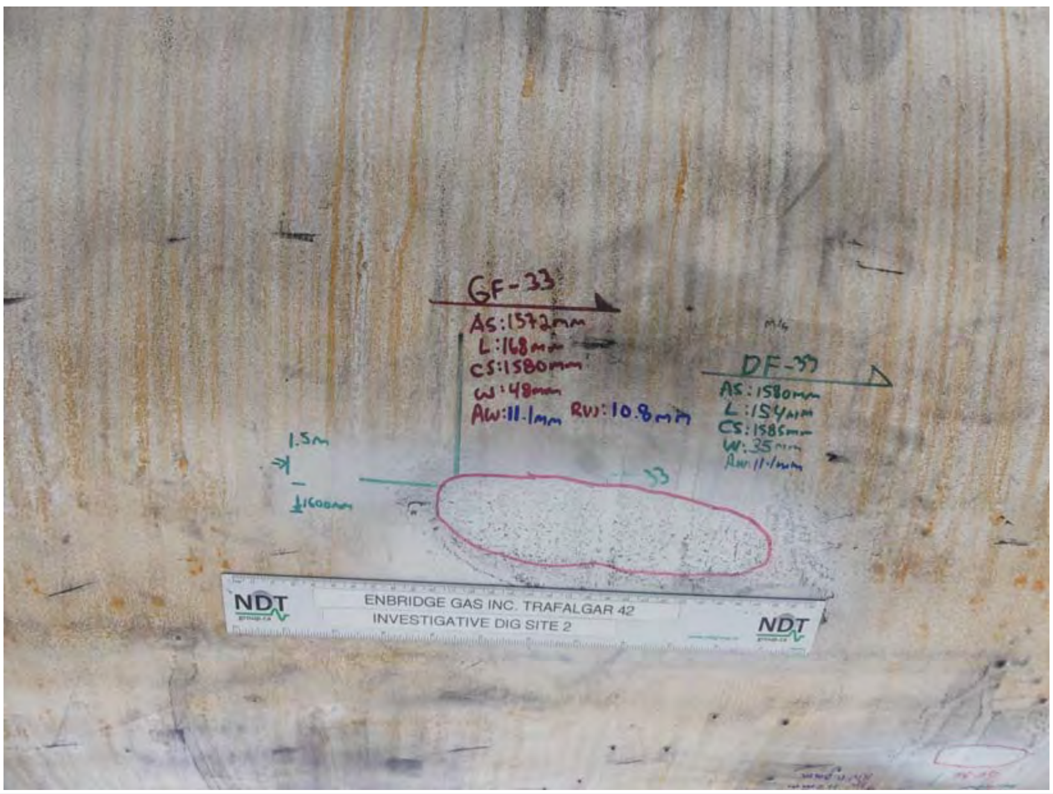


189 - GF-31

ENBRIDGE GAS INC. - TRAFALGAR NPS42

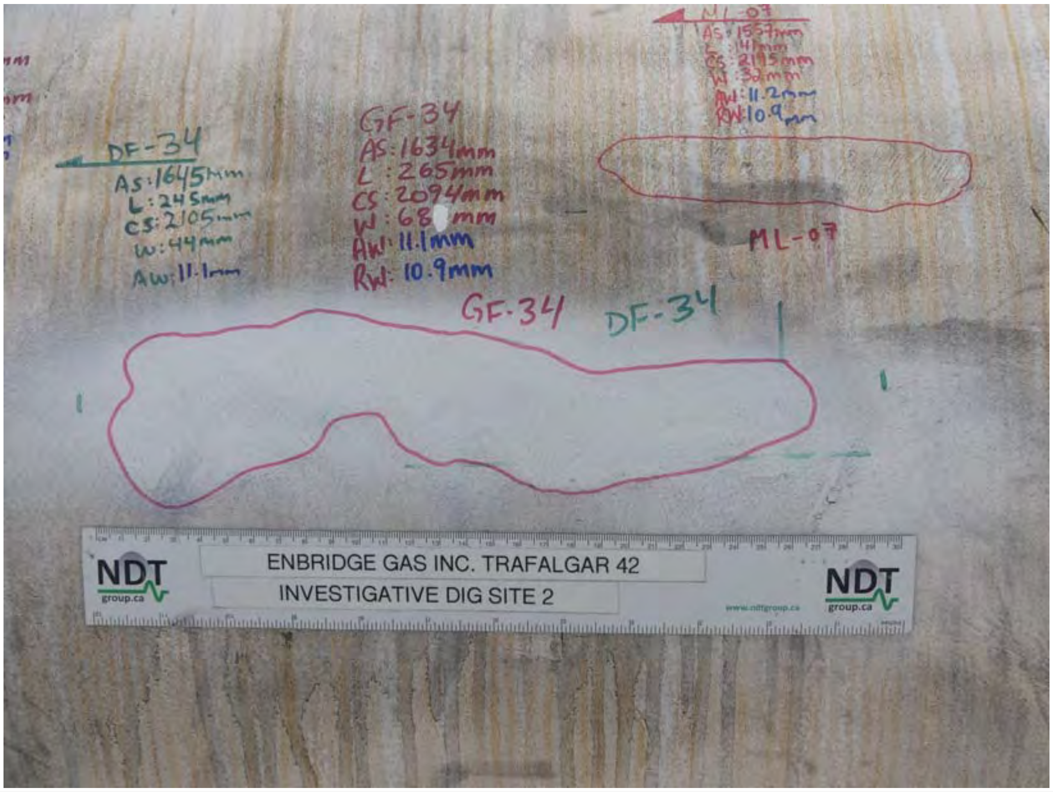


190 - GF-32

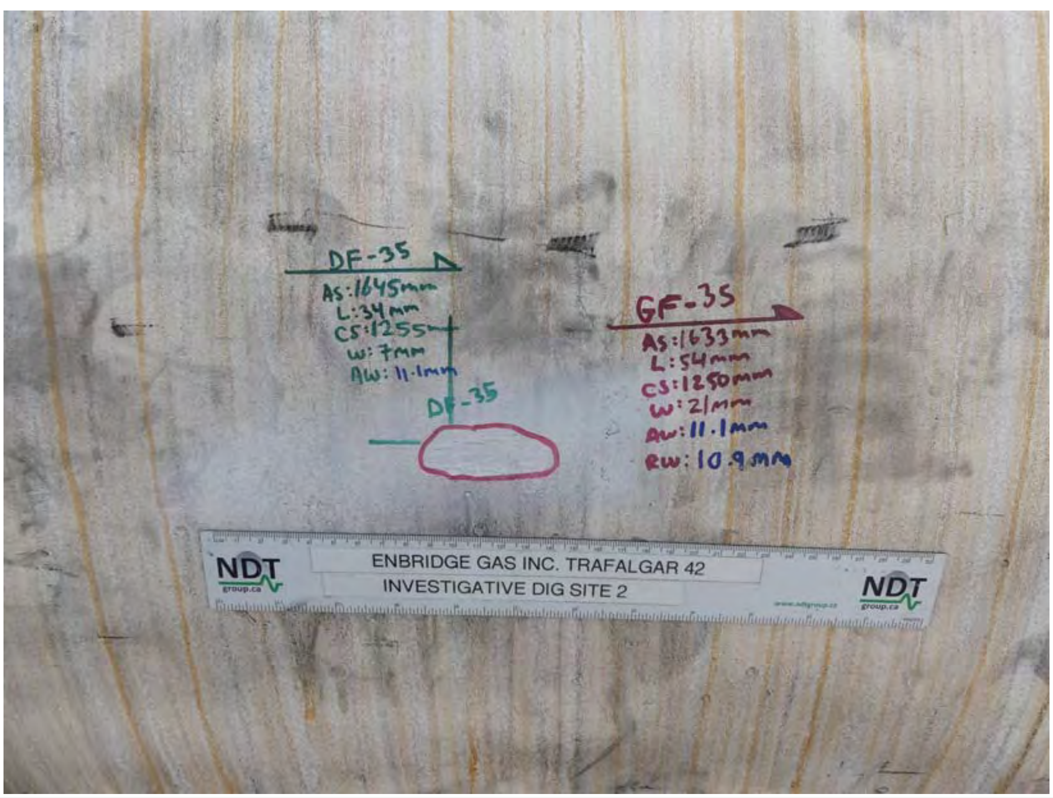


191 - GF-33

ENBRIDGE GAS INC. - TRAFALGAR NPS42

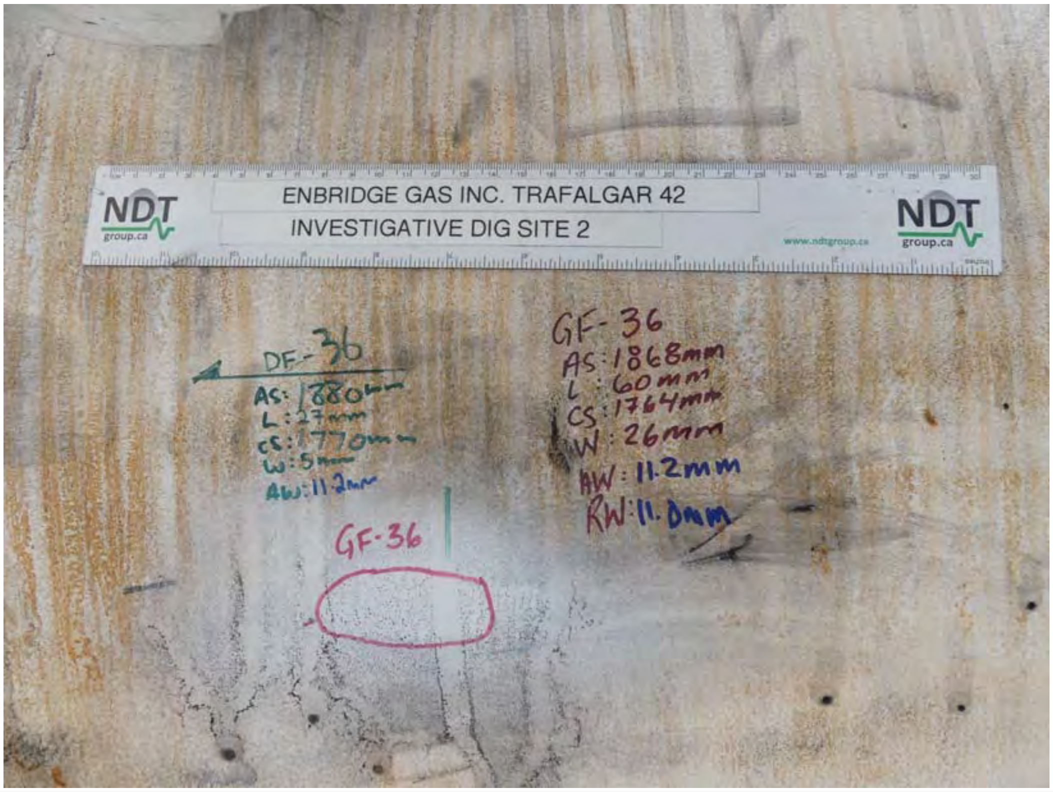


192 - GF-34

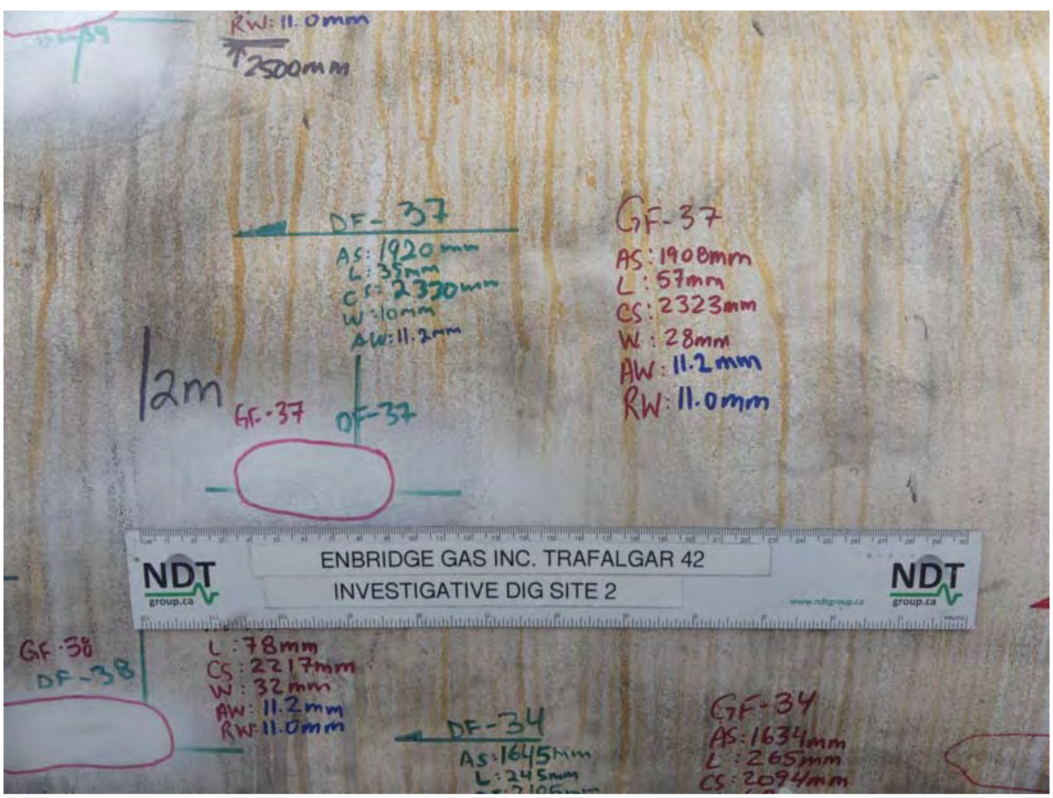


193 - GF-35

ENBRIDGE GAS INC. - TRAFALGAR NPS42

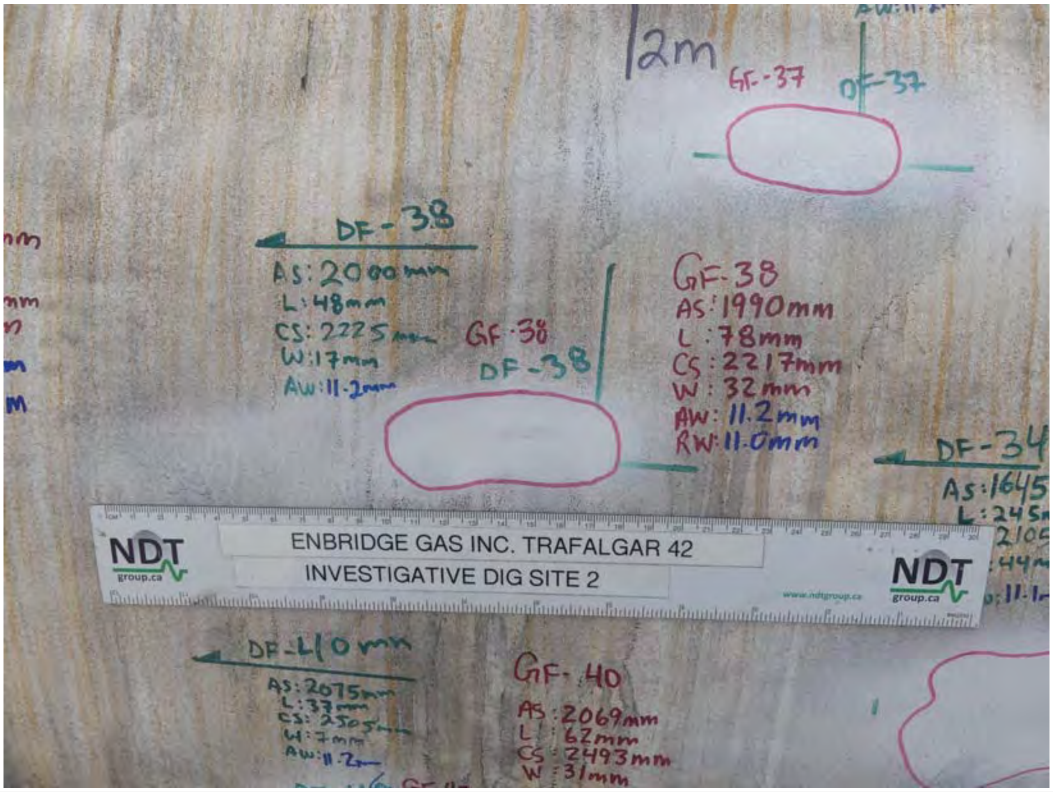


194 - GF-36

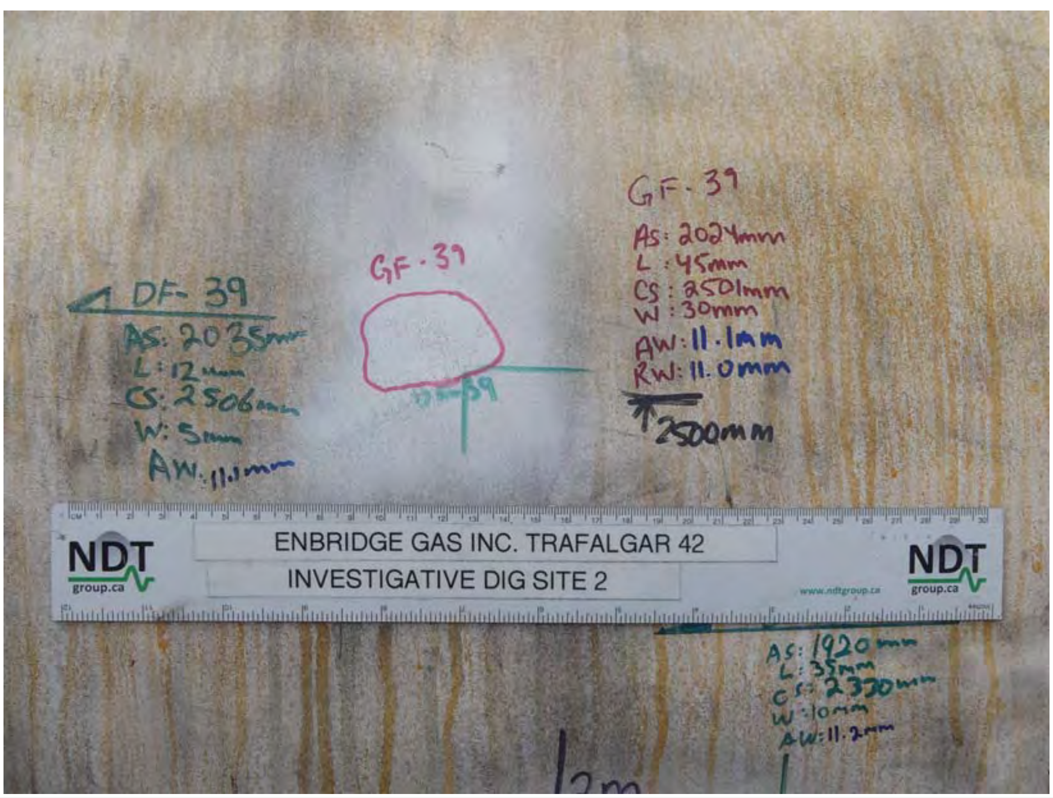


195 - GF-37

ENBRIDGE GAS INC. - TRAFALGAR NPS42

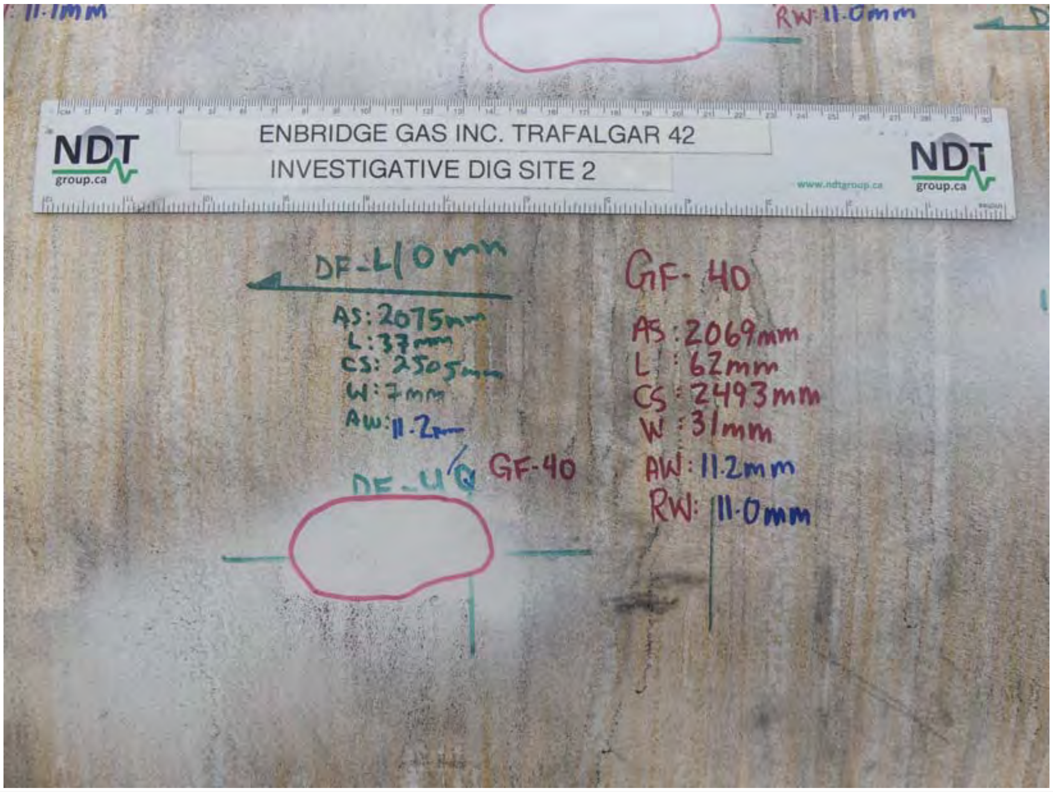


196 - GF-38



197 - GF-39

ENBRIDGE GAS INC. - TRAFALGAR NPS42



198 - GF-40

CORROSION SERVICE

2005 Integrity Assessment	FINAL REPORT

Integrity Assessment of the UNION GAS 42" TRAFALGAR LINE Dawn Plant – Cuthbert Road

DEO-05-9349-U-0

Prepared for: Union Gas Limited • Integrity Management Program
50 Keil Dr. N., Chatham, ON N7M 5M1

Copy	Department	Location
1.	Integrity Mgmt. Program	Head Office
2.	Corrosion Specialist	Chatham
3.	Corrosion Technician	Dawn

Surveyed by:
S. Mott, P. Eng., Systems Specialist
NACE Cathodic Protection Technician #9826

Prepared by:
S. Segall, P. Eng., Technical Manager
NACE Cathodic Protection Specialist #5087

Approved by:
W. Shim, P. Eng., President & CEO
NACE Corrosion Specialist 'P' #4679

Date: February 2007

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Corrosion Service Company Limited (CSCL) was retained by Union Gas Limited (UGL) to conduct an External Corrosion Direct Assessment (ECDA) process on the 42" Trafalgar Line, between Dawn Plant and Cuthbert Road, as part of UGL's 2005 Pipeline Integrity Management Plan (IMP).

The pre-assessment step of the ECDA process was finalized in May 2005. The data were reviewed and integrated in the format suggested in Table 1 of NACE Standard RP0502-2002.

The results of the pre-assessment step indicated that the ECDA process was not applicable as an acceptable integrity assessment tool on the subject line, due to the risk of electrical shielding caused by disbonded Polyken coating.

Union Gas Limited (UGL) however instructed Corrosion Service (CSCL) to conduct indirect inspections along the line and to recommend locations for bell hole examinations, in order to provide additional data to be used by UGL for their risk assessment.

The indirect inspections were conducted in July 2005 and two locations were selected for bell hole examinations.

The results of the bell hole examinations confirmed that at some areas the coating was disbonded. At Site #1, wrinkling and poor adhesion were observed at overlaps, while at Site #2 tenting[1] was apparent at the longitudinal and girth welds.

Some areas under the disbonded coating were not protected (i.e. pH of trapped water was 7), however only minor to moderate metal loss occurred after 30 years of exposure and the maximum depth of the corroded area did not exceed 16% of the nominal wall thickness of the pipe.

The corroded areas were inspected by others (i.e. Canspec) and were considered as acceptable for service at the established MAOP.

/...cont'd

[1] Tenting is defined as a tent-shaped void formed along the girth weld or longitudinal seam-weld reinforcement in a pipe, when the external coating is not in continuous intimate contact with the pipe and weld surfaces.

EXECUTIVE SUMMARY CONT'D

Pit growth calculations were performed in order to assist UGL in establishing the re-assessment interval. Assuming that the maximum reassessment interval shall not exceed the limits established for ECDA in Table 3 of ASME B318S-2004 (i.e. 10 years with a sample of indications examined), the maximum pit growth after 10 more years of exposure (i.e. in 2015) was estimated and is expected not to exceed 6 mils for a total depth of 76 mils. For future reference, the maximum depth after 20 more years of exposure (i.e. in 2025) would not be expected to exceed 80 mils. For both these pit growth values, UGL has verified the integrity of the pipe and it was considered as acceptable for service at the established MAOP (see Appendix B).

The ECDA related indirect inspection techniques can identify holidays in the coating where moisture ingress can occur and where pitting corrosion can take place. Identifying these areas for bell hole examinations can assist in assessing the severity of corrosion and in calculating future corrosion pitting rates for similar pits in unexcavated portions of the pipeline.

1.0 GENERAL

Corrosion Service Company Limited (CSCL) was retained by Union Gas Limited (UGL) to conduct an External Corrosion Direct Assessment (ECDA) process on the 42" Trafalgar Line, between Dawn Plant and Cuthbert Road, as part of UGL's 2005 Pipeline Integrity Management Plan (IMP).

The pre-assessment step of the ECDA process was performed in May 2005 and the ECDA process was not considered as an applicable risk assessment technique, due to the risk of electrical shielding caused by disbonded coating.

UGL selected the bell hole examination technique as an alternative integrity assessment methodology and CSCL was instructed to conduct indirect inspections using ECDA related techniques in order to determine the number and locations of bell hole examinations.

The indirect inspections were conducted in July 2005 and the bell hole examinations were performed from October 18 to October 20, 2005.

Technical notes were submitted to UGL at the end of each step. The ECDA pre-assessment report and the two technical notes were re-edited into one comprehensive final report for ease of reference.

2.0 TECHNICAL APPROACH

The pre-assessment work was based on the methodology detailed in NACE Standard RP0502-2002, which is intended to serve as a guideline for applying the External Corrosion Direct Assessment (ECDA) process on typical pipeline situations.

The indirect inspections were conducted using ECDA related techniques, however their scope was limited to providing additional data to be used by UGL in their risk assessment.

Pit growth calculations were performed to assist UGL in establishing the reassessment interval.

During the pre-assessment step, all of the pipeline features were referenced by the line chainage as indicated in the UGL Alignment Sheets (i.e. alignment chainages). During the following steps (i.e. indirect inspections and bell hole examinations), the features were referenced by chainages "as measured" on site (i.e. site chainages). The site chainages were typically measured using the wire dispenser counter and checked using the sub-meter GPS coordinates. The GPS coordinates were recorded every 20 meters, at indications and at reference points, such as bends, valves, centerlines of the roads, etc. In case of erroneous records from the wire dispenser counter, the site chainages are calculated using the sub-meter GPS coordinates.

When the difference between the alignment chainages and the site chainages at the reference points was less than 5%, the site chainages were adjusted to match the alignment chainages. The chainage of any location between two reference points was determined by interpolating the difference between the alignment and site chainages at the adjacent reference points. The reference points, complete with GPS coordinates are listed in Table 2-1.

Table 2-1 • 42" Trafalgar Line. GPS/Chainage Reference Points

GPS Coordinates		Chainage (m)		Description
Longitude	Latitude	Alignment	Site	
-82.2174006	42.7159680	0.00	0.00	Station 10G-374 (Dawn). Fence
-82.2161165	42.7164243	-	68.20	Bell Hole Examination #1
-82.2124511	42.7177154	-	399.00	Bell Hole Examination #2
-82.2092518	42.7188376	690.70	690.70	Station CLF-10G-303V. Fence

3.1 GENERAL

The objectives of the pre-assessment step were to confirm the feasibility of the ECDA for the line under evaluation, to select the indirect inspection tools and to define the ECDA regions, in accordance with Section 3 of the NACE Standard RP0502-2002.

The majority of the pre-assessment data were collected by Union Gas Limited (UGL) as part of their extensive risk assessment data base. The data includes strip maps, original drawings, aerial photos, alignment sheets, and maintenance data.

Additional data such as proximity of the line to other structures, influence of foreign rectifiers, soil resistivity data, etc. were obtained from available public domain information and included.

The data were reviewed and integrated in the format suggested in Table 1 of the NACE Standard RP0502-2002.

The data were then evaluated to confirm it was comprehensive enough to allow evaluating the feasibility of ECDA, selecting the indirect tools, and defining the ECDA regions.

The feasibility of the ECDA on the section Dawn Plant - Cuthbert Road of the 42" Trafalgar Line was assessed in accordance with the guidelines indicated in Section 3.3 of the NACE Standard RP0502-2002.

3.2 DATA COLLECTION

The following is a summary of the data collected under the Pre-Assessment step of the ECDA. The complete integrated data are tabulated in Table 3-1.

The 42" diameter, 691 m long section of the 42" Trafalgar Line between Dawn Plant and Cuthbert Road Valve Site 10G-303V was installed in 1975.

The 42" pipeline section under assessment starts at the fence of UGL North Dawn Plant (i.e. Station 10G-374) and runs east to end at the fence of the Valve Site 10G –303V, west of Cuthbert Road (chainage 690.70 m).

The piping and the joints are coated with Polyken tape.

The soil consists mainly of clay.

There are no major drainage or slope differences to justify separate ECDA regions.

3.2 DATA COLLECTION CONT'D

The pipeline is bonded into the Dawn Plant, sharing protection with the plant piping and the main lines converging to the plant. The following UGL rectifiers are expected to provide protection in this area:

- North Plant: #191, #224, #192, #190, and #281
- South Plant: #200, #279, #278, #272, #273 (Out of Service), #274, #277, and #282 (groundbed being replaced)
- 5985 Pool: #131

At the other end, the line is electrically isolated from the east section of the Trafalgar Line and shares protection from rectifier #271 with the piping inside the valve site.

No significant influence is expected from TCPL Great Lakes (USA) rectifiers.

Two test posts (TP1 and TP3) are installed at the two ends of the line.

Regular maintenance included bi-annual ON potential readings at the test posts. No CP downtime was reported on this line.

Close interval potential surveys (CIPS) were conducted in 1993 and 1994, interrupting the bond across the isolating flange and the rectifiers #102, #69, #119, #103, and #120. The recorded OFF potentials were more electronegative than -1100 mV_{CSE} at all locations.

No in-line inspections (ILI) were performed along the line.

There are no records of leaks, corrosion attack, or third party damage on the line.

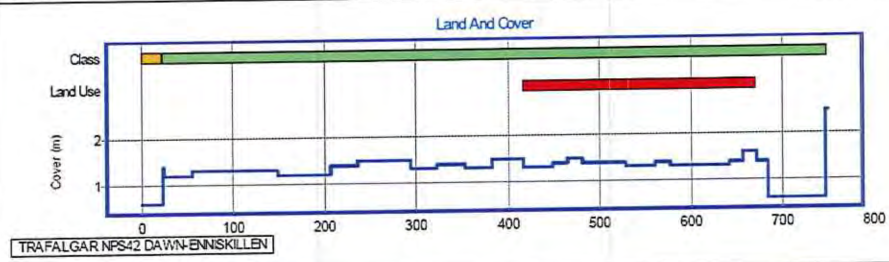
Table 3-1 • Pre-Assessment Data

PIPE-RELATED DATA	
Material:	Steel
Diameter:	42" (1067 mm)
Wall Thickness:	12.7 mm, from Ch. 0.00 m to Ch. 23.70 m
	11.2 mm, from Ch. 23.70 m to Ch. 690.80 m
Year Manufactured	Unknown
Seam Type:	DSAW[1]-Spiral
Bare Pipe:	No

[1] Double submerged arc welded

3.2 DATA COLLECTION CONT'D

Table 3-1 • Pre-Assessment Data Cont'd

CONSTRUCTION-RELATED DATA	
Year Installed:	1975
Route Changes / Modifications:	None
Route Maps / Aerial Photos:	Maps and aerial photos available
Construction Season Score:	May 02 to December 31
Location of Valves, Tie-ins, etc.:	Ch. 0.00 m Dawn Valve Site
	Ch. 23.70 m to 23.80 m, Valve Site
	Ch. 690.70 m, Valve Site
Casings:	None
Bends:	None
Depth of Cover:	
Underwater Section:	None
Location of Weights:	None
Proximity to Other Structures:	UGL main lines, TCPL and Enbridge Gas lines
SOILS/ENVIRONMENTAL	
Soil:	Clay
Land Use:	Agricultural (Typical)
Paved Roads:	None
Drainage:	No major changes to justify separate ECDA regions
Topography:	No special features
Frozen Ground:	No frozen areas expected during indirect inspections
CORROSION CONTROL	
CP System:	Impressed Current. Rectifiers #271 and Dawn Plant CP System
Stray Currents:	Possible sources: TCPL (US rectifiers), Enbridge Gas

3.2 DATA COLLECTION CONT'D

Table 3-1 • Pre-Assessment Data Cont'd

CORROSION CONTROL Cont'd	
Test Posts:	TP #1, at Dawn North Plant
	TP #3, at Cuthbert Valve Site
CP Criteria:	-1000 mV_{CSE} ON potential for bi-annual test post survey
CP Maintenance:	Bi-annual surveys at test posts
Years Without CP:	None
Coating Type - Pipe:	Polyken Tape
Coating Type - Joints:	Polyken Tape
Coating Condition:	Unknown
Current Demand:	Less than 1A, including valve site piping
CP Survey Data:	ON potentials measured bi-annually at the test stations were more electronegative than -1000 mV_{CSE}
Pipe Temperature:	No significant differences to justify separate ECDA regions
OPERATIONAL DATA	
Monitoring Programs:	Leak inspection (typically once a year)
Pipe Inspection Reports:	None
Repair History:	None
Leak / Rupture History:	None
Evidence of MIC:	None
Third Party Damage:	Unknown
Previous A/G Surveys:	See CP survey data above
Hydrotest Dates:	Unknown
ILI, CIS Runs, etc.:	CIPS in 1993, 1994

3.3 ECDA FEASIBILITY ASSESSMENT

Due to the poor record of the Polyken coating adhesion to the pipe, there is a significant risk of the ECDA process being affected by disbonded coating.

As such, we do not consider the ECDA process as an applicable integrity assessment technique on this line.

4.1 GENERAL

The results of the ECDA feasibility assessment indicated that there is a significant risk of the ECDA process being affected by electrical shielding, due to the poor record of the Polyken polyethylene tape coating in terms of coating disbonding. Therefore, the ECDA was not considered as an applicable integrity assessment technique on the subject line in accordance with Paragraph 3.3.1.1 of NACE Standard RP0502-2002.

Alternative techniques to assess the integrity of the line are in-line inspection (ILI) and bell hole examination. Both these techniques require specific considerations when applied on the 42" Dawn-Cuthbert line.

The ILI technique would be extremely expensive for such a short segment of pipeline (i.e. 691 m), since there are no pigging facilities. The bell hole examination technique requires additional information to determine the number and location of excavations.

After considering all these factors, Union Gas Limited (UGL) instructed Corrosion Service to conduct indirect inspections along the line and to recommend locations for bell hole examinations, in order to provide additional data to be used by UGL for their risk assessment.

Accordingly, Corrosion Service conducted an integrated CIPS/DCVG survey at 1 meter spacing over the pipeline route.

4.2 INDIRECT INSPECTION RESULTS

4.2.1 Protection Level

The results of the integrated CIPS/DCVG survey (shown in Figures 4-1 and 4-2[1]) indicate that possible areas of damaged coating on pipe in direct contact with the soil are fully protected. The protection level of exposed steel under disbonded coating is unknown, because of dielectric shielding of the polyethylene tape.

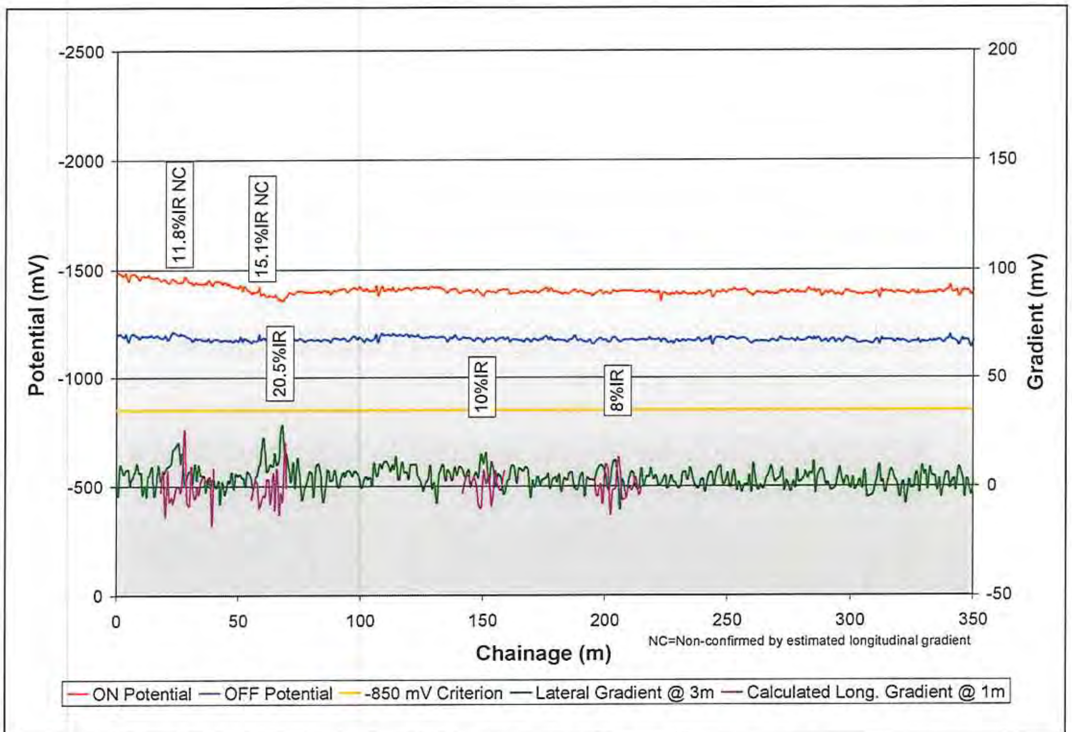


Figure 4-1 • 42" Trafalgar Line. Dawn – Cuthbert. Ch. 0 - 350m. CIPS/DCVG Integrated Survey

[1] Sections of the calculated longitudinal gradient were removed to improve chart clarity.

4.2 INDIRECT INSPECTION RESULTS CONT'D

4.2.1 Protection Level Cont'd

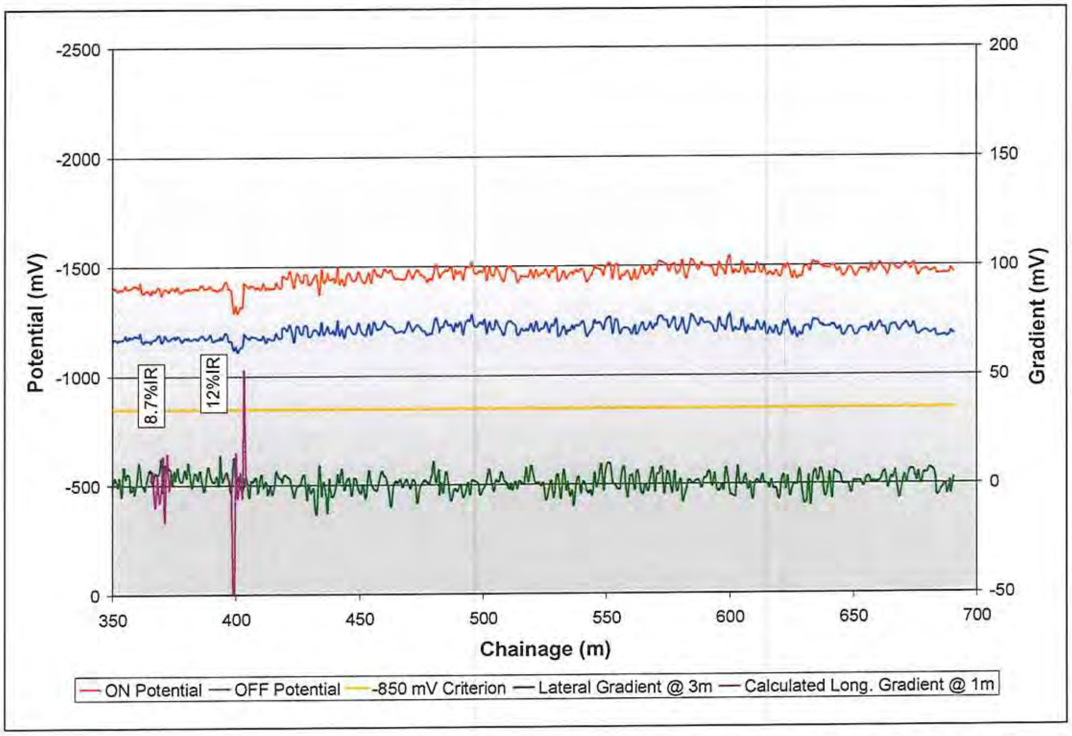


Figure 4-2 • 42" Trafalgar Line. Dawn – Cuthbert. Ch. 350 - 691m. Integrated CIPS/DCVG Survey

Additional data from two SCC digs previously performed on this section of line indicated that the pipe displayed light rust with small, very shallow pits at Dig #1 (August 1994) and light rust with shallow pits and calcareous deposits at Dig #111 (August 2001).

Based on the survey results and the data available from the two SCC examinations, it appears that the cathodic protection system has maintained the pipe for 26 years (1975 – 2001) with no significant corrosion metal loss at the exposed areas in contact with the soil and at two locations under disbonded coating.

4.2.2 Coating Condition

The results of the SCC examinations indicated very poor coating at the two dig sites (i.e. one technician commented that the exposed coating at Dig #1 was "the worst coating I've ever seen. No bond to primer. Wrinkled back exposing the pipe.").

4.2 INDIRECT INSPECTION RESULTS CONT'D

4.2.2 Coating Condition Cont'd

The integrated CIPS/DCVG survey found one 20.5%IR indication at chainage 68.20 m, a drop in pipe-to-soil potential at chainage 399.00 m, and several locations displaying lateral gradients of up to 15%IR. Note that for a disbonded polyethylene tape coating with numerous wrinkles, the typical shape of the gradient versus distance curve at a holiday may be distorted, especially for the "calculated longitudinal gradient". Therefore, it is expected that an excavation at chainage 68.20 m could provide information regarding the pipe condition at an area with possible coating defects.

An excavation at chainage 399.00 m could clarify the reasons for the potential depression at this location and the subsequent peaks displayed by the calculated longitudinal gradient.

Excavations at chainage 204.40 m and at chainage 369.70 m (8%IR and 8.7%IR) might reveal relatively small holidays. Note that coating holidays are also possible water ingress points and subsequently probable locations for disbonding coating.

4.3 CONCLUSIONS AND RECOMMENDATIONS

The susceptibility of the Polyken polyethylene tape coating to disbondment and shielding, particularly in clay soils, precludes the use of the ECDA as an applicable integrity assessment technique. The results of two SCC digs performed along the line confirmed that the coating was indeed disbonded and in poor condition.

Both the results of the CIPS and the visual examination at the previous SCC dig sites indicate that the pipe is cathodically protected when in direct contact with the soil. Furthermore, the visual examination found light corrosion under disbonded coating, with no significant corrosion metal loss after 19 years (Dig #1) and 26 years (Dig #111) of exposure.

With visual examination data limited to two dig sites and with the high cost of the in-line inspection, UGL should consider conducting additional bell hole examinations to complete the risk assessment on the subject line. The recommended sites are:

a) Chainage 68.20 m. GPS Coordinates: -82.2161165, 42.7164243. The examination may provide information regarding the pipe condition at an area with possible coating defects (i.e.20.5%IR).

b) Chainage 399.00 m. GPS Coordinates: -82.2124511, 42.7177154. The examination may clarify the reasons for the potential depression at this location and the subsequent peaks displayed by the calculated longitudinal gradient.

5.1 GENERAL

The bell hole examinations were conducted from October 18 to October 20, 2005.

The detailed excavation data, including selected photographs are shown in Appendix A. Complete sets of pipe photographs are provided on a separate disk.

For the purpose of this report the terms *Bell Hole Examination Location* and *Bell Hole Examination Site* are used interchangeably.

5.2 SELECTED BELL HOLE EXAMINATION LOCATIONS

The sites selected for bell hole examination are:

a) Chainage 68.20 m. GPS Coordinates: -82.2161165, 42.7164243. The examination could provide information regarding the pipe condition at an area with possible coating defects (i.e.20.5%IR).

b) Chainage 399.00 m. GPS Coordinates: -82.2124511, 42.7177154. The examination might clarify the reasons for the potential depression at this location and the subsequent peaks displayed by the calculated longitudinal gradient

5.3 BELL HOLE EXAMINATION DATA

5.3.1 Site #1. Chainage 68.20 m

This site displayed a minor DCVG indication (i.e. 20.5%IR) and overlapped the end of the 2001 SCC dig #111. The indication is located in a level, well drained area, as shown in Photograph 5-1.

Photograph 5-1 • Site #1. General View. Looking West

The original coating was Polyken tape and the 2002 repair was done using epoxy coating and Denso tape, as shown in Photograph 5-2. The complete coating inspection map (CIM) is attached in Appendix A.

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.1 Site #1. Chainage 68.20 m Cont'd

**Photograph 5-2 • Site #1. Open Trench.
General View. Looking East**

The soil around the pipe was wet clay with a resistivity of 980 Ω-cm.

The coating was found in poor condition, as shown in Photographs 5-3 to 5-6. The photographs are typically identified by line chainage. The distance to the west end of the excavation is indicated in brackets for ease of reference in relation to the Coating Inspection Map. A complete photo mapping scan[1] of the coated pipe from four different directions is included on a separate disk.

[1] Overlapping photographs were taken along the entire length of the excavation, from west to east.

5.3 BELL HOLE EXAMINATION DATA CONT'D

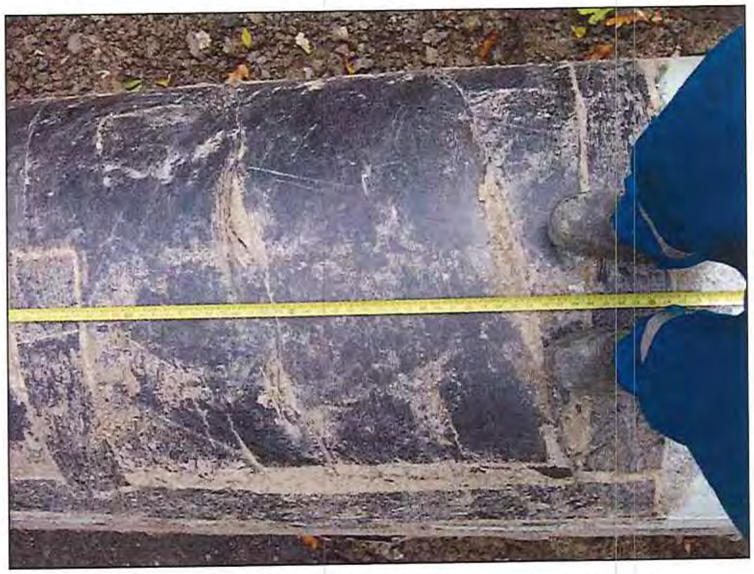
5.3.1 Site #1. Chainage 68.20 m Cont'd

Photograph 5-3 • Site #1. Sample of Coating Damage. Ch. 68.45m (540cm)

Photograph 5-4 • Site #1. Sample of Coating Damage. Ch. 69.45m (640cm)

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.1 Site #1. Chainage 68.20 m Cont'd



Photograph 5-5 • Site #1. Disbonded Coating at Overlap

Photograph 5-6 • Site #1. Wrinkled Coating. Looking South

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.1 Site #1. Chainage 68.20 m Cont'd

Typically, the Polyken tape appears disbonded at overlaps. A 5 cm wide strip of bare pipe was identified at the interface between the original Polyken tape and the epoxy coating, as shown in the Coating Inspection Map. Multiple wrinkles were visible, especially at 3 o'clock (or looking north inside the trench), almost along the entire length of the excavation.

After removing the coating, it was found that most of the corrosion was superficial, with brown staining and calcareous deposits, as shown in Photographs 5-7 to 5-9.

Photograph 5-7 • Site #1. Pipe Exposed.
General Corrosion & Calcareous Deposits

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.1 Site #1. Chainage 68.20 m Cont'd

Photograph 5-8 • Site #1. Pipe Exposed.
General Corrosion & Calcareous Deposits. Close View

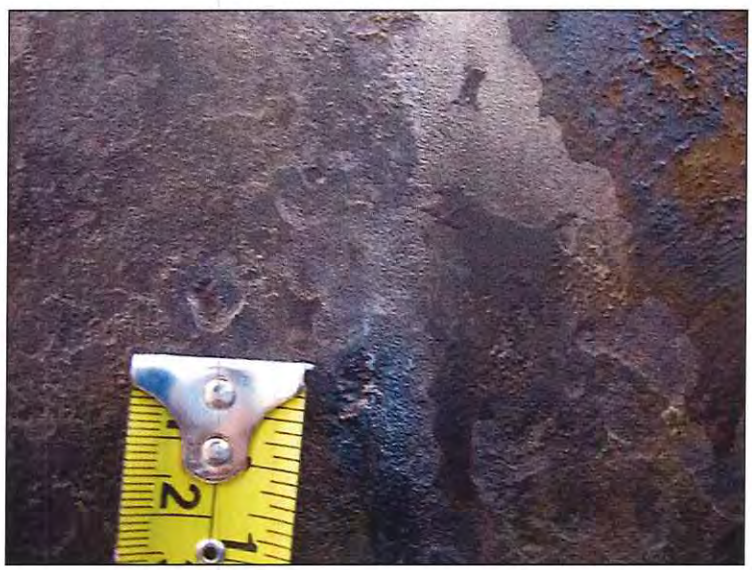
Photograph 5-9 • Site #1. Pipe Exposed. Corrosion at Overlaps

Three clusters of shallow active pits were found under disbonded coating, ranging in depth from 10 mils to 50 mils, as shown in Photographs 5-10 to 5-15. A complete photo mapping scan[1] of the pipe after removing the coating is included on a separate disk.

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.1 Site #1. Chainage 68.20 m Cont'd

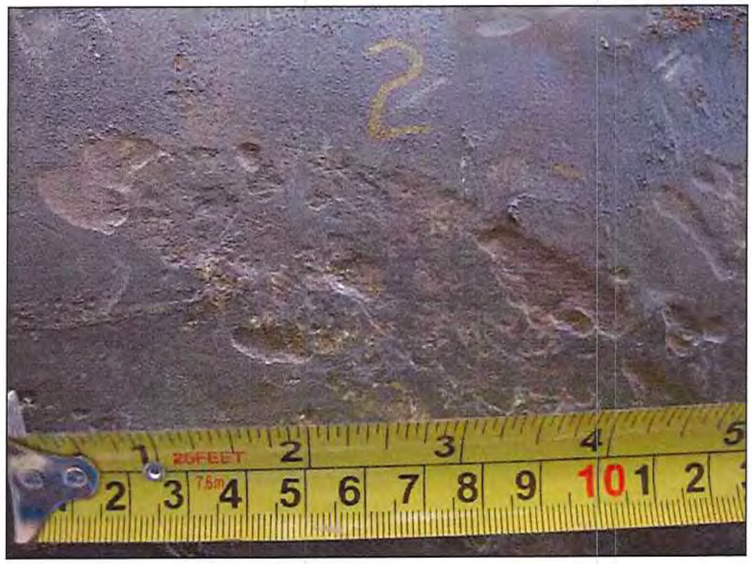
Photograph 5-10 • Site #1. Pit Cluster #1. Ch. 70.1m (7.05m)



Photograph 5-11 • Site #1. Pit Cluster #1. Ch. 70.1m (7.05m). Close View

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.1 Site #1. Chainage 68.20 m Cont'd

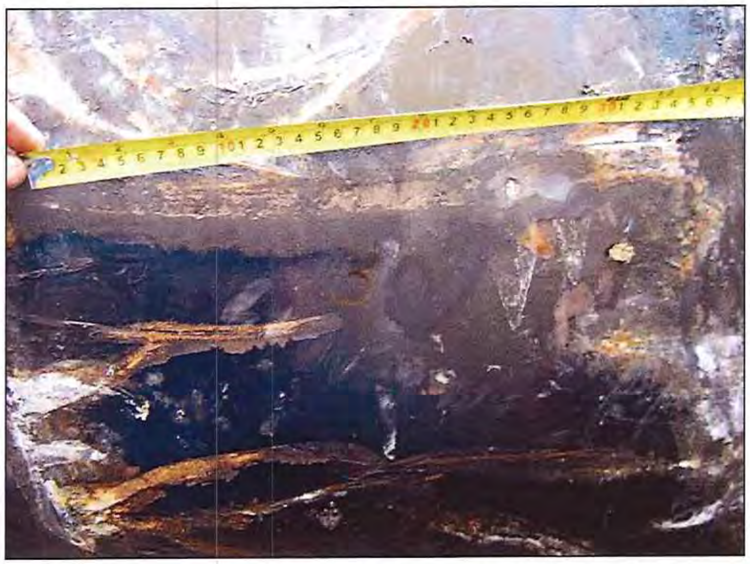


Photograph 5-12 • Site #1. Pit Cluster #2. Ch. 69.45m (6.4m)

Photograph 5-13 • Site #1. Pit Cluster #2. Ch. 69.45m (6.4m). Close View

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.1 Site #1. Chainage 68.20 m Cont'd



Photograph 5-14 • Site #1. Pit Cluster #3. Ch. 67.65m (4.6m)

Photograph 5-15 • Site #1. Pit Cluster #3. Ch. 67.65m (4.6m). Close View

The presence of the calcareous deposits indicates that some pipe areas are fully protected, while the neutral pH of the water trapped under the disbonded coating (i.e. 7) shows that other areas are shielded from the protection current. The pits were examined by others (i.e. Canspec) and the corroded area was considered as acceptable for service at the established MAOP.

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.2 Site #2. Chainage 399.00 m

This site displayed a significant drop in the pipe-to-soil potentials and significant peaks in the calculated longitudinal gradient, associated with a DCVG indication. The indication is located in a level, well drained area, as shown in Photograph 5-16.

Photograph 5-16 • Site #2. General View. Looking West

The field applied coating was Polyken tape, as shown in Photograph 5-17.

Photograph 5-17 • Site #2. Open Trench. General View. Looking West

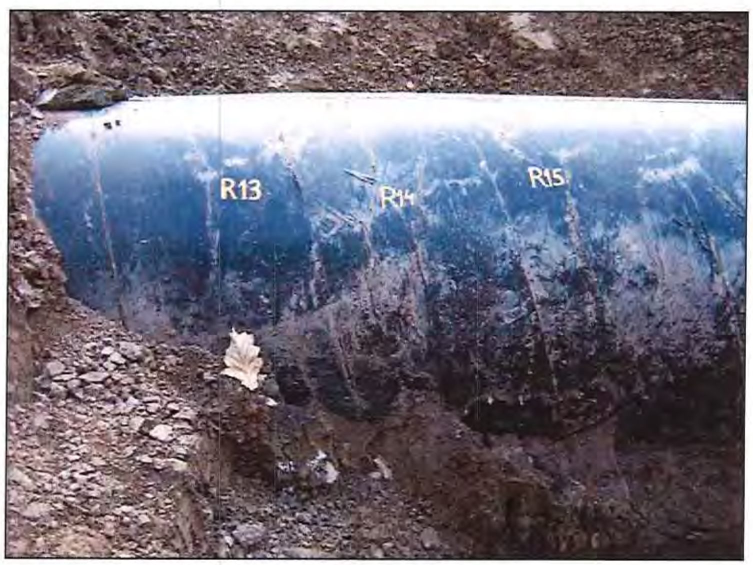
5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.2 Site #2. Chainage 399.00 m Cont'd

The soil around the pipe was wet clay with a resistivity of 3900 Ω-cm.

Disbonded coating was typically found along the longitudinal welds, as shown in Photographs 5-18 to 5-20.

Photograph 5-18 • Site #2. Sample of Disbonded Coating along Longitudinal Weld. Looking North



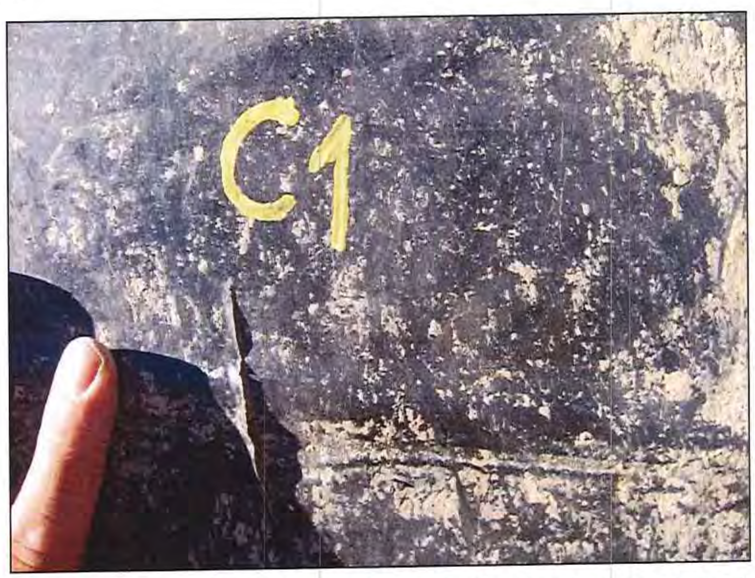
Photograph 5-19 • Site #2. Sample of Disbonded Coating along Longitudinal Weld. Looking South

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.2 Site #2. Chainage 399.00 m Cont'd

Photograph 5-20 • Site #2. Sample of Disbonded Coating along Longitudinal Weld. Close View

Additional coating damage, such as cuts or probe punctures, are shown in Photographs 5-21 and 5-22.



Photograph 5-21 • Site #2. Coating Damage. Sample of Coating Cut (C1)

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.2 Site #2. Chainage 399.00 m Cont'd

Photograph 5-22 • Site #2. Sample of Coating Damage by Locating Probe (P2)

A complete photo mapping scan[1] of the longitudinal welds, with all coating defects clearly marked in paint is shown in Appendix A. Sample photographs of the defects are also included. Close views of each defect are included on a separate disk.

The coating was removed along the entire circumference of the girth weld and along the longitudinal weld from chainage 397.00m (2.2m from the west end of the excavation) to chainage 402.60m (7.6m), as shown in Photographs 5-23 and 5-24.

Photograph 5-23 • Site #2. Pipe Exposed at Girth Weld

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.2 Site #2. Chainage 399.00 m Cont'd

Photograph 5-24 • Site #2. Pipe Exposed at Longitudinal Weld

The pipe displayed numerous shallow pits (i.e. 10 to 70 mils) along the welds, as well as general corrosion (Photographs 5-25 to 5-27).

Photograph 5-25 • Site #2. Sample of Shallow Pit (R12-Pit #1)

5.3 BELL HOLE EXAMINATION DATA CONT'D

5.3.2 Site #2. Chainage 399.00 m Cont'd

Photograph 5-26 • Site #2. Sample of Shallow Pits (R12-Pit #'s 2, 3 & 4)

Photograph 5-27 • Site #2. Exposed Pipe. Close View

A complete photo mapping scan[1] of the longitudinal welds during the coating removal, as well as close views of all the corroded areas are included on a separate disk.

The presence of the calcareous deposits indicates that some pipe areas are fully protected, while the neutral pH of the water trapped under the disbonded coating (i.e. 7) shows that other areas are shielded from the protection current. The pits were examined by others (i.e. Canspec) and the corroded area was considered as acceptable for service at the established MAOP.

5.4 DATA ANALYSIS

The bell hole examinations confirmed that the Polyken tape coating on the line exhibited various degrees of disbondment. The affected areas were typically at overlaps (Site #1) and at welds (Site #2).

Some areas under the disbonded coating were not cathodically protected (i.e. pH of trapped water was 7).

Superficial corrosion and minor to moderate pitting were observed under the disbonded coating, although the maximum pit depth did not exceed 50 mils for Site #1 and 70 mils for Site #2, after 30 years of exposure.

The shallow depth of the pits at the unprotected areas is attributed to oxygen depletion in clay soil, as the replenishment rate of the trapped water under the disbonded coating is very low. It is reasoned that the oxygen contained in the trapped water was consumed during the initial formation of the pit. The oxygen diffusion rate was further reduced by the polarization of the cathodic areas at the base of the pit, under cathodic protection.

The maximum pit depth (i.e. 70 mils) was matched with the literature data for the same type of soil,[2] in order to predict the pit growth[3].

The maximum pit depth is given by the equation:

$$P = k_{5.3} \times \left(\frac{T}{5.3} \right)^n$$

where:

P = depth of the deepest pit at time T (mils)
$k_{5.3}$ = depth of the deepest pit after 5.3 years; for the selected Soil #2 (Bell clay) = 45.4 mils
T = Time of exposure (years)
n = constant; for selected Soil #2 (Bell clay) = 0.34

Assuming that the oxygen depletion occurred after the first 5 years, $k_{5.3}$ remains unchanged (i.e. 45.4 mils), and the constant n for the exposure of the 42" Trafalgar line would be obtained solving the equation:

$$70 = 45.4 \times \left(\frac{30}{5.3} \right)^n, \text{ or } n = 0.25$$

[2] M. Romanoff – Underground Corrosion, National Bureau of Standards, Circular 579, 1957, Soil #2 (Bell Clay).
[3] Pit growth calculations were performed in order to assist UGL in establishing the re-assessment interval for pipeline integrity.

5.4 DATA ANALYSIS CONT'D

The two curves are shown in Figure 5-1, with the original Romanoff data (Bell Clay Data) representing the worst case of unprotected pipe sample exposed in clay soil.

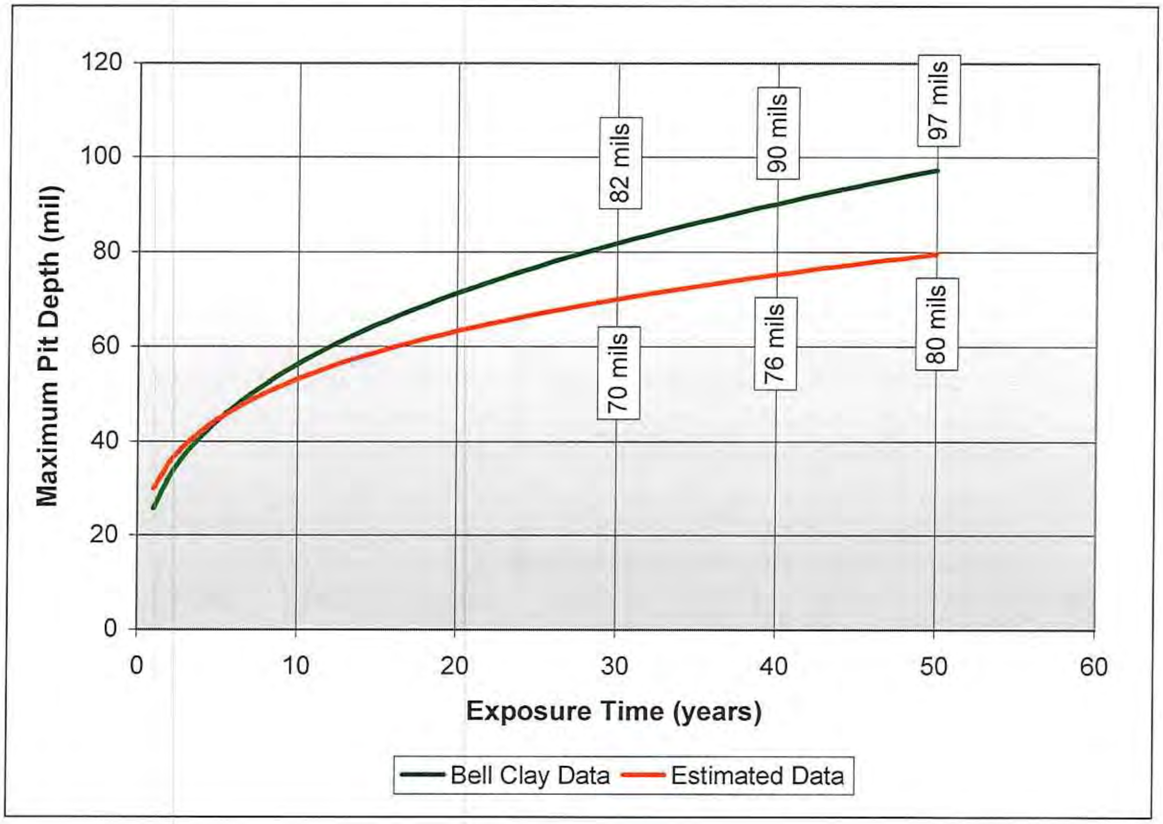


Figure 5-1 • Estimated Maximum Pit Depth

The maximum depth of unexcavated pits after 10 more years of exposure[4] (i.e. 40 years of exposure) would not be expected to exceed 76 mils, or an additional increase of 6 mils. The maximum depth after 20 more years of exposure (i.e. 50 years of exposure) would not be expected to exceed 80 mils.

[4] Maximum reassessment interval for ECDA with a sample of indications examined, according to Table 3 of ASME B31.8S-2004.

5.5 CONCLUSIONS

The results of the bell hole examinations confirmed that at some areas the coating was disbonded. At Site #1, wrinkling and poor adhesion were observed at overlaps, while at Site #2 tenting[5] was apparent at the longitudinal and girth welds.

Some areas under the disbonded coating were not protected (i.e. pH of trapped water was 7), however no significant metal loss occurred after 30 years of exposure and the maximum depth of the corroded area did not exceed 16% of the nominal wall thickness of the pipe.

The corroded areas were inspected by others (i.e. Canspec) and were considered as acceptable for service at the established MAOP.

[5] Tenting is defined as a tent-shaped void formed along the girth weld or longitudinal seam-weld reinforcement in a pipe, when the external coating is not in continuous intimate contact with the pipe and weld surfaces.

6.0 CONCLUSIONS

The maximum pit growth after 10 more years of exposure[1] (i.e. in 2015) would not be expected to exceed 6 mils for a total depth of 76 mils. The maximum depth after 20 more years of exposure (i.e. in 2025) would not be expected to exceed 80 mils. For these pit growth values, UGL has verified the integrity of the pipe and it was considered as acceptable for service at the established MAOP (see Appendix B).

The ECDA related indirect inspection techniques can identify holidays in the coating where moisture ingress can occur and where pitting corrosion can take place. Identifying these areas for bell hole examinations can assist in assessing the severity of corrosion and in calculating future corrosion pitting rates for similar pits in unexcavated portions of the pipeline.

[1] Maximum reassessment interval for ECDA with a sample of indications examined, according to Table 3 of ASME B31.8S-2004

CORROSION SERVICE

APPENDIX A

Excavation Data

CORROSION SERVICE

Appendix A-1

Site 1 Excavation

- Field Observations Form
  – Site Characteristics
  – Site Sketch
  – Coating Inspection Map
  – Corrosion Grid Map
- Photographs

CORROSION SERVICE

Bell Hole Examination

Client: Union Gas Ltd.

Surveyor: S. Mott / A. Marcu

Date: October 19-20, 2005 **Time:** 10:00 (•) AM ( ) PM

Conditions: **Temp.** 4 (•) °C ( ) °F **Weather** Overcast

1) General

Pipeline: Trafalgar - Dawn to Cuthbert **Pipe Size:** 42"

Location: Site # 1 **Chainage:** 68.2m

Nearest Intersection: Bentpath Line & Cuthbert Road

Notes:

Possible coating defects (20.5%IR).

2) Site Characteristics

Landform Pattern: Level

Drainage: Well Drained

Terrain: Cleared Bush

R.O.W. Characteristics: Multiple Pipelines (3 Union Gas Lines)

Notes:

CORROSION SERVICE

Bell Hole Examination

3) Soil Data

General Description: Topsoil over clay

Colour: Brown

SPECIFIC DATA	Soil Type	Resistivity (Ω-cm)	pH	Temp. (●) °C ( ) °F	Moisture
At Surface	Topsoil (30cm)	3600	7.75	14.1	Medium
Midway	Clay	1500	7.82	14.3	Wet
At Pipe Depth	Clay	980	7.38	16.2	Wet

Notes:

4) Coating Information (As Found)

Coating Type: Polyken Tape / Epoxy / Denso Tape

Age: ~1975 / ~2002 / ~2002

Factory/Field Applied: Field

Overall Condition: Generally fair but poor at overlaps and some repair areas.

Overall Adhesion: Generally good but poor at overlaps.

Disbondment/Damage: 0.05m strip of bare pipe below the longitudinal seam @ interface of Polyken Tape to epoxy. Disbonded at overlaps.

Water Under Coating? Yes **Water pH:** 7

Notes:

Appears to be the end of the 2001 SCC dig #111 (49.1m dig starting at Ch. 0.018).

CORROSION SERVICE

Bell Hole Examination

5) Pipe Surface Condition

Cleaning Method : Hand Tools

Amount Cleaned : 7 meters

Corrosion Detected : Yes

Type of Corrosion : Surface Stains & Pitting

Corrosion Deposits : Yes **Colour :** Brown

Pitting:

No. of Pits Found : 3 Clusters of Shallow Pits

Depth of Pits : Min: 0.01 ( ) cm (•) inches
Max: 0.05 ( ) cm (•) inches

Location of Pitting : Typically at tape overlap.

Notes:

	Length	Width	Location	Max.	# Pits
Pit Cluster #1 @ 7.05m from west edge of excavation	0.5m	0.4m	7:30	0.04	14
Pit Cluster #2 @ 6.40m from west edge of excavation	0.3m	0.4m	7:30	0.05	17
Pit Cluster #3 @ 4.60m from west edge of excavation	0.45m	0.03m	9:00	0.04	3

6) Ultrasonic Measurements

TEST LOCATION	Description	Unit of Measure: ( ) cm (•) inches							
		Position on Pipe							
		12:00	1:30	3:00	4:30	6:00	7:30	9:00	10:30
No. 1	4.0m from west edge of excavation	0.433	0.441	0.438	0.442	0.441	0.437	0.432	0.436
No. 2	6.5m from west edge of excavation	0.439	0.443	0.439	0.441	0.443	0.441	0.439	0.440
No. 3	-	-	-	-	-	-	-	-	-

Notes:

Set @ 0.2300 in/µs.

CORROSION SERVICE

Bell Hole Examination

7) Cathodic Protection of Pipe

Is there a CP system? (•) Yes ( ) No   Is it functioning? (•) Yes ( ) No   Type of System: Impressed Current

System Output:

Rectifier / Test Post No.	Protected Pipeline	Voltage (V)	Current (A)	Taps
R 271	Trafalgar Line	2.54	0.25	16%
R 191	Dawn Station Piping	11.4	14.2	C-2, F-3
R 190	Dawn Station Piping	9.5	6.7	C-2, F-5
R 272	Dawn Station Piping	47.2	3.3	26%
R 40	8" London Lines	23.7	24.1	C-3, F-1
R 30	Dawn West Lines	18.6	26.4	-
R 131	5985 Pool Line	22	25.2	C-B, F-4
R 192	Dawn Station Piping	7.5	9.9	C-2, F-4
R 224	Dawn Station Piping	10.1	19.3	C-B, C-3
R 135	156 Pool Lines	14	26	C-B, F-1
R 102	Trafalgar Lines	7.5	3.4	C-B, F-3
R 17	Booth Creek Pool	9	3	45%
R 18	Booth Creek Pool	13	10	C-3, F-2
R 200	Dawn Station Piping	10	13	C-B, F-3
R 274	Dawn Station Piping	26	6.9	C-4, F-1
R 278	Dawn Station Piping	27	9	C-D, F-4

Output of Anodes in TS :   U/S of Excavation: N/A   D/S of Excavation: N/A

DC Potentials at Excavation Site

POTENTIAL in mV (•) CSE ( ) SRE ( ) ZRE	At Grade	1/2 Way	At Pipe Depth (Low IR Drop)
Upstream[1] Side of Excavation	-1527	-1531	-1458
Downstream Side of Excavation	-1536	-1521	-1540

[1]Upstream is according to chainage.

AC Potentials at Excavation Site

U/S side of Excavation: 0.14 Volts AC   D/S side of Excavation: 0.14 Volts AC

Is there a DC transit system nearby? No   Distance: -

Are there High Voltage AC lines nearby? No   Distance: -

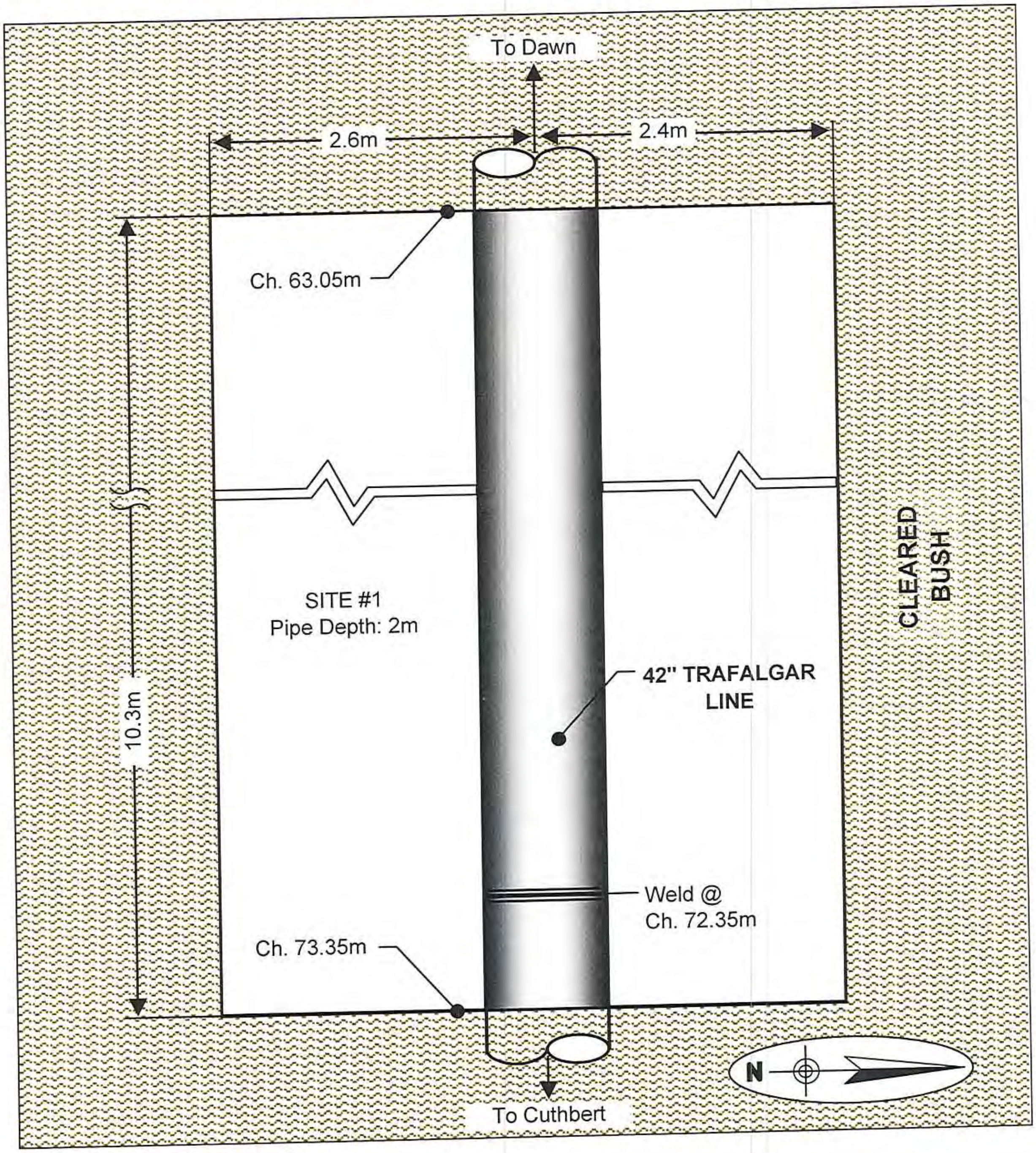
Notes:

CORROSION SERVICE

Bell Hole Examination

8) Sketch of Excavation Site and Measurement Locations

NOTE:
Include dimensions of excavation, distance to nearest aboveground structure, bends, crossing structures, and north arrow. Measure and record chainages of excavation limits and any anomalies found at site.



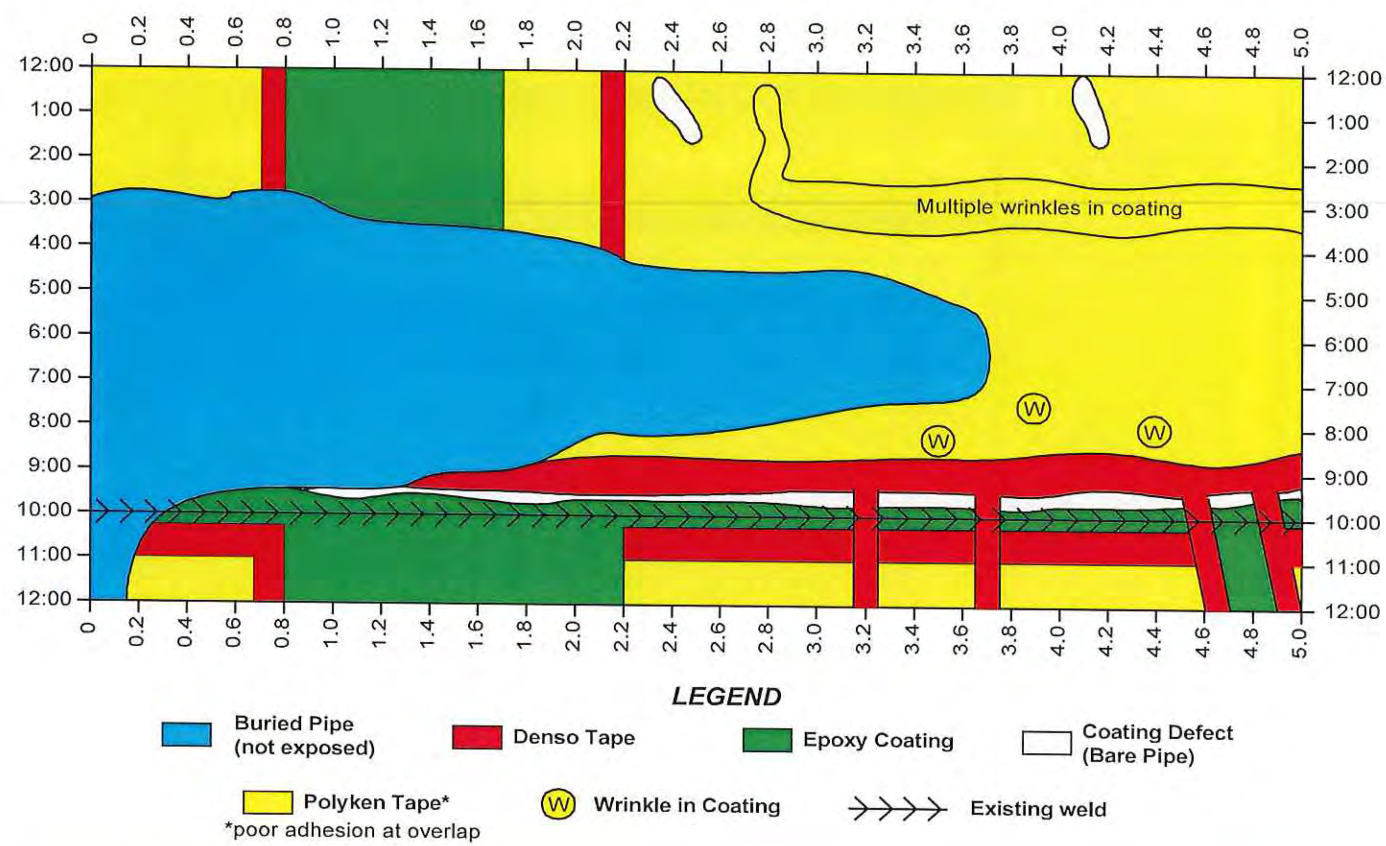
CORROSION SERVICE

Bell Hole Examination

9) Coating Inspection Map

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

Chainage: 68.2m
Site: 1



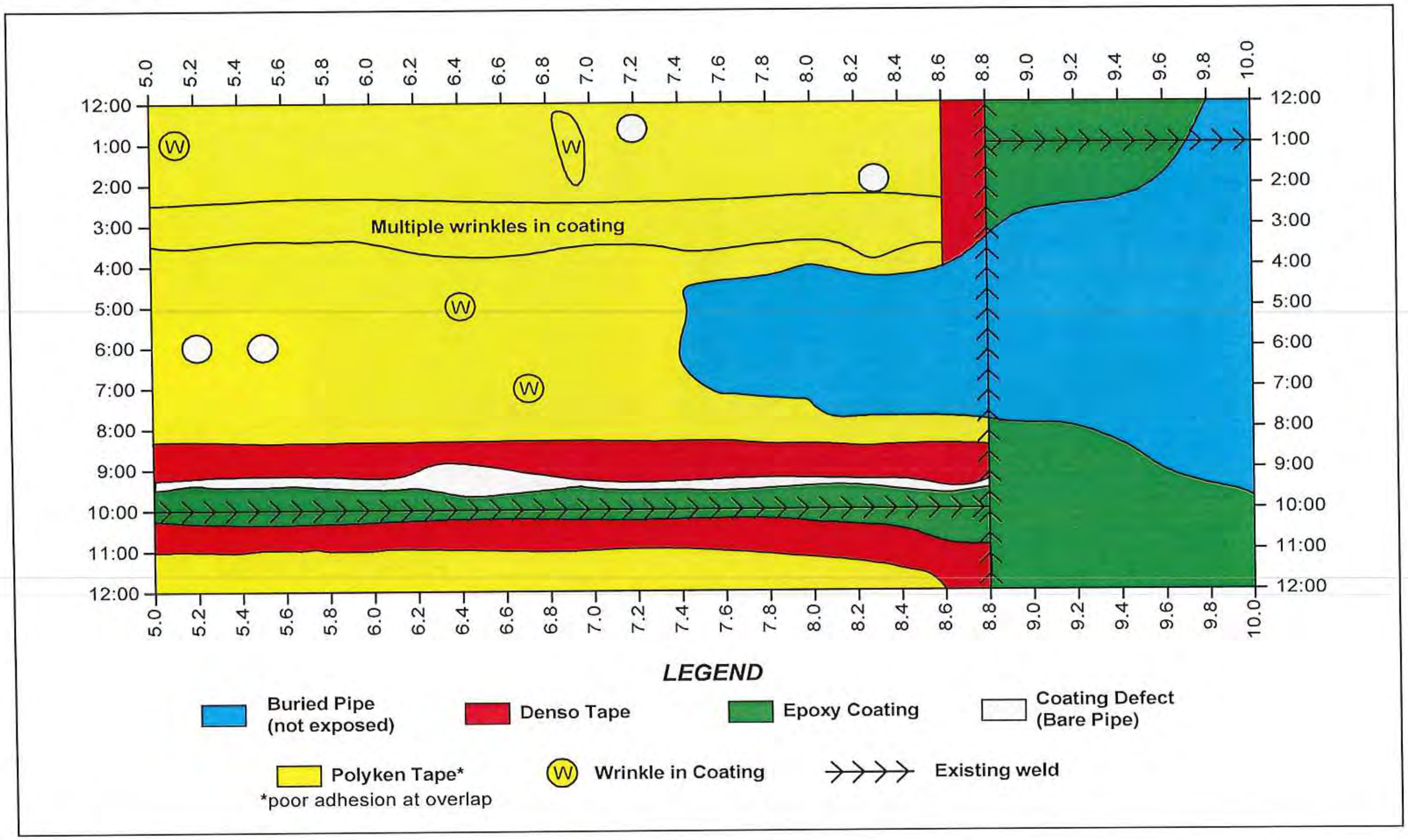
CORROSION SERVICE

Bell Hole Examination

9) Coating Inspection Map Cont'd

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

Chainage: 68.2m
Site: 1



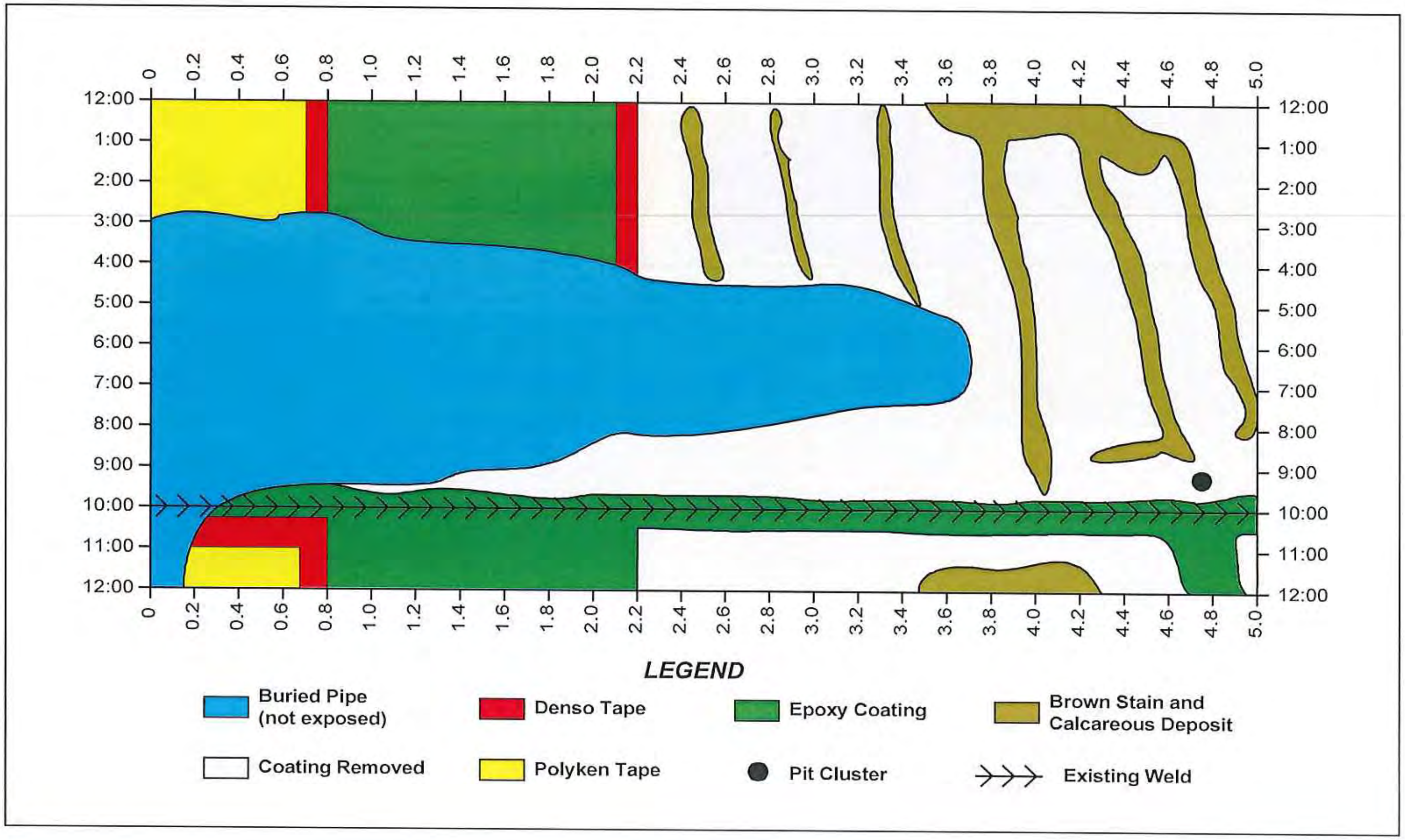
CORROSION SERVICE

Bell Hole Examination

10) Corrosion Grid Map

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

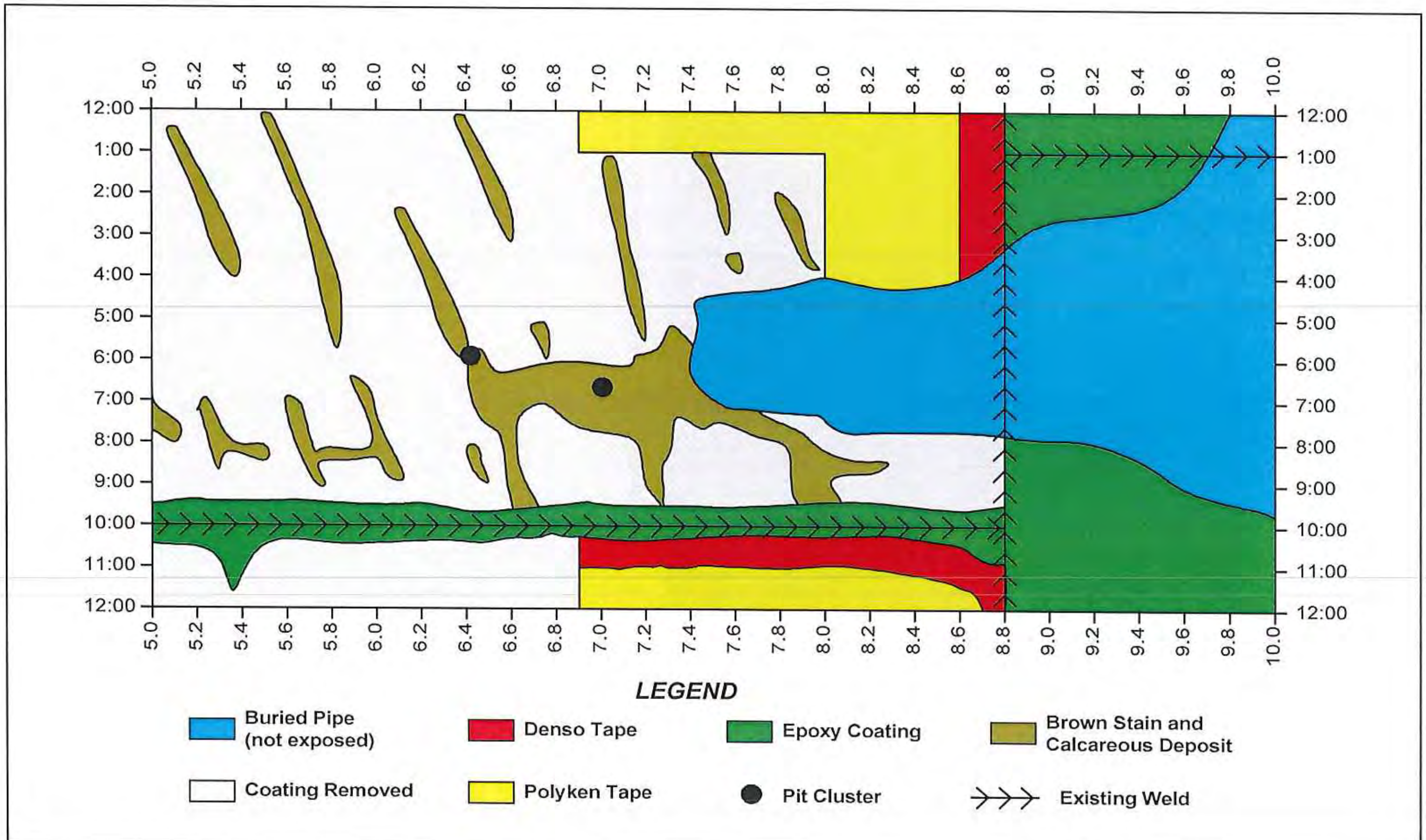
Chainage: 68.2m
Site: 1



10) Corrosion Grid Map Cont'd

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

Chainage: 68.2m
Site: 1



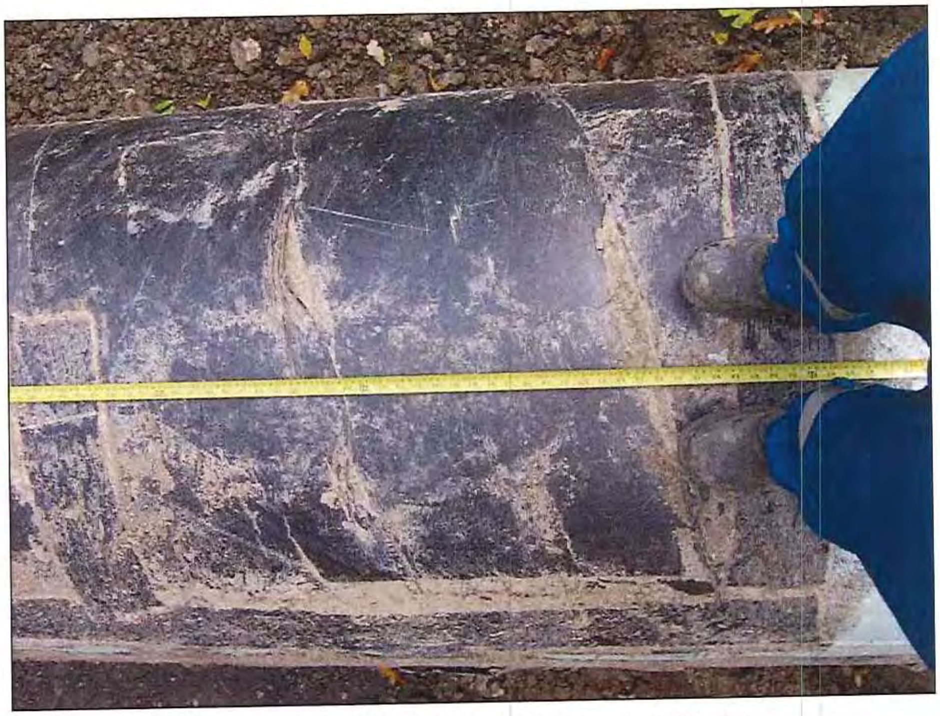
SITE 1 - PHOTOGRAPHS

Photograph 1 • Site 1. General View. Looking West.

Photograph 2 • Site 1. Open Trench. General View. Looking West.

Photograph 3 • Site 1. Sample of Coating Damage. Ch. 68.45m (5.40m).

Photograph 4 • Site 1. Sample of Coating Damage. Ch. 69.45 (6.40m).



Photograph 5 • Site 1. Disbonded Coating at Overlap.

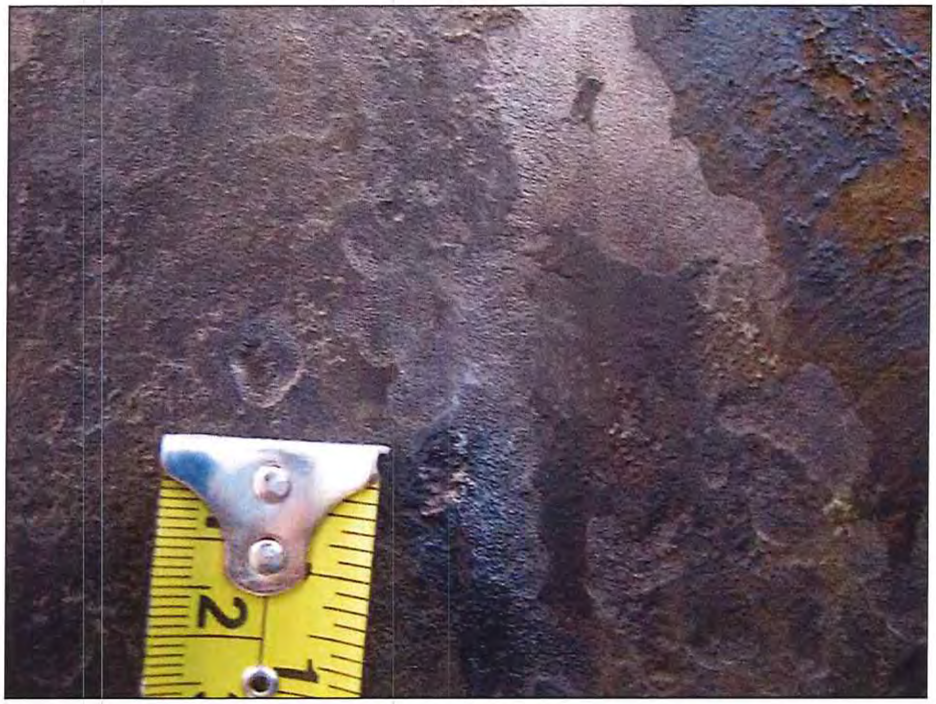
Photograph 6 • Site 1. Wrinkled Coating. Looking South.

Photograph 7 • Site 1. General Corrosion and Calcareous Deposits.

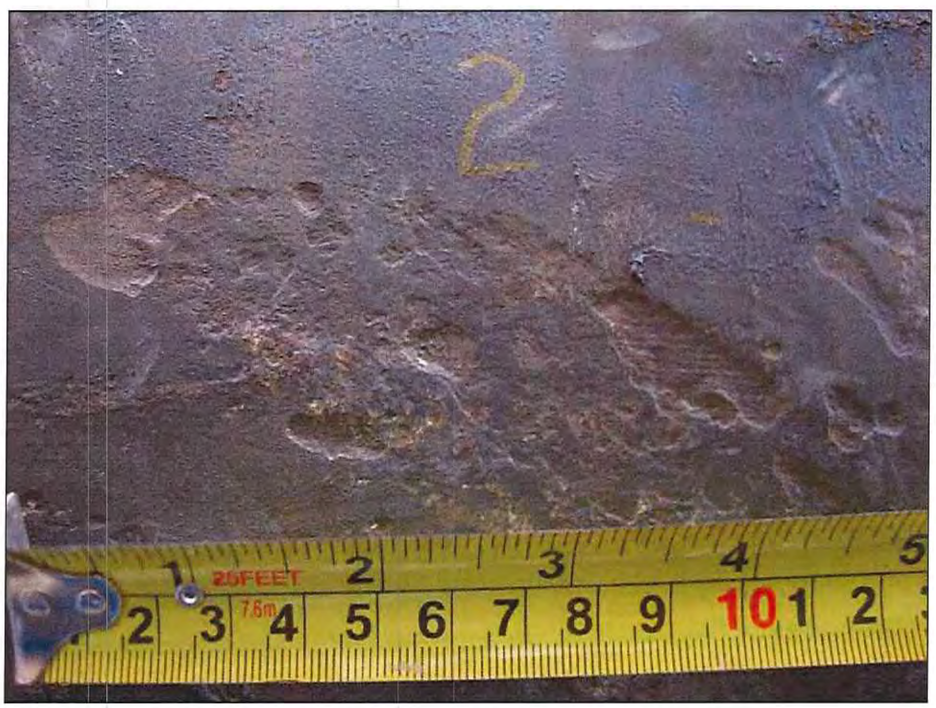
Photograph 8 • Site 1. General Corrosion and Calcareous Deposits. Close View.

Photograph 9 • Site 1. Pipe Exposed. Corrosion at Overlaps.

Photograph 10 • Site 1. Pit Cluster #1. Ch. 70.10m (7.05m). General View.

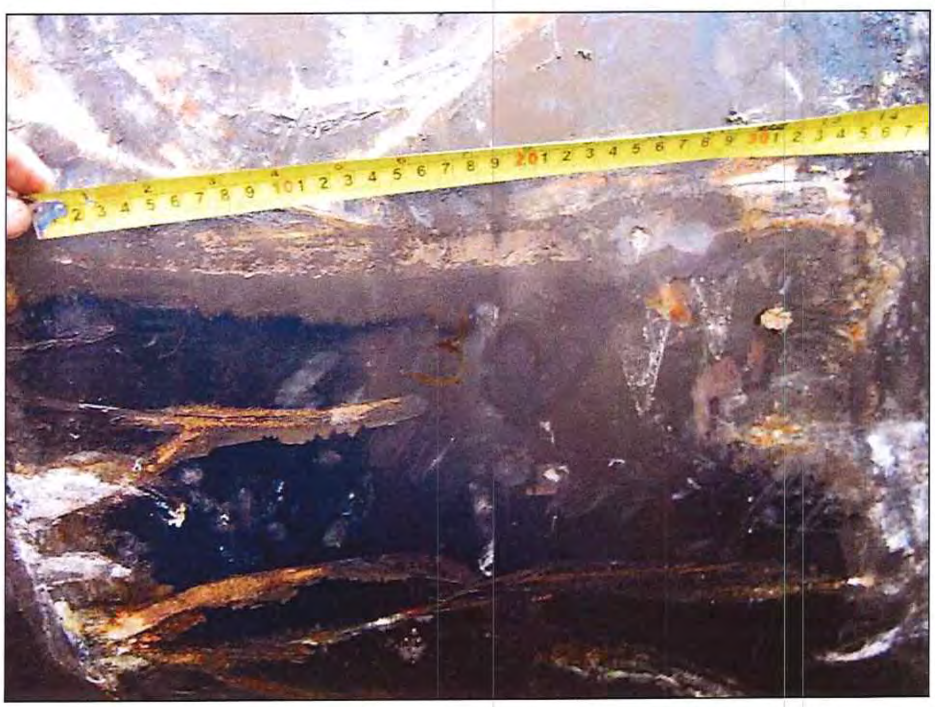


Photograph 11 • Site 1. Pit Cluster #1. Ch. 70.10m (7.05m). Close View.



Photograph 12 • Site 1. Pit Cluster #2. Ch. 69.45m (6.40m). General View.

Photograph 13 • Site 1. Pit Cluster #2. Ch. 69.45m (6.40m). Close View.



Photograph 14 • Site 1. Pit Cluster #3. Ch. 67.65m (4.60m). General View.

Photograph 15 • Site 1. Pit Cluster #3. Ch. 67.65m (4.60m). Close View.

CORROSION SERVICE

Appendix A-2

Site 2 Excavation

- Field Observations Form
  – Site Characteristics
  – Site Sketch
  – Coating Inspection Map
  – Corrosion Grid Map
- Photographs

CORROSION SERVICE

Bell Hole Examination

Client: Union Gas Ltd.

Surveyor: S. Mott / A. Marcu

Date: October 18-19, 2005 **Time:** 12:00 ◯ AM ◉ PM

Conditions: **Temp.** 15 ◉ °C ◯ °F **Weather** A Mix of Sun and Cloud

1) General

Pipeline: Trafalgar - Dawn to Cuthbert **Pipe Size:** 42"

Location: Site # 2 **Chainage:** 399m

Nearest Intersection: Bentpath Line & Cuthbert Road

Notes:

The line displays a significant drop in potential.

2) Site Characteristics

Landform Pattern: Level

Drainage: Well Drained

Terrain: Cleared Bush

R.O.W. Characteristics: Multiple Pipelines (3 Total)

Notes:

CORROSION SERVICE

Bell Hole Examination

3) Soil Data

General Description: Topsoil over clay

Colour: Brown

SPECIFIC DATA	Soil Type	Resistivity (Ω-cm)	pH	Temp. (●) °C ( ) °F	Moisture
At Surface	Topsoil (0.3m)	6800	7.55	21.4	Wet
Midway	Clay	2500	7.18	21.8	Wet
At Pipe Depth	Clay	3900	7.16	22.6	Wet

Notes:

4) Coating Information (As Found)

Coating Type: Polyken Polyethylene Tape

Age: 1975

Factory/Field Applied: Field

Overall Condition: Generally fair but poor at welds.

Overall Adhesion: Good except or tenting at welds.

Disbondment/Damage: Multiple wrinkles, disbonded all along the longitudinal and girth welds.

Water Under Coating? Yes **Water pH:** 7

Notes:

CORROSION SERVICE

Bell Hole Examination

5) Pipe Surface Condition

Cleaning Method : Hand Tools

Amount Cleaned : 8 meters

Corrosion Detected : Yes

Type of Corrosion : Pitting and Staining

Corrosion Deposits : Yes **Colour :** Brown

Pitting: **No. of Pits Found :** Many Shallow Pits

Depth of Pits : Min: 0.01 ◯ cm ◉ inches

Max: 0.07 ◯ cm ◉ inches

Location of Pitting : Along Longitudinal & Girth Welds

Notes:

6) Ultrasonic Measurements

TEST LOCATION	Description	Unit of Measure: ◯ cm ◉ inches							
		Position on Pipe							
		12:00	1:30	3:00	4:30	6:00	7:30	9:00	10:30
No. 1	2.19m from west edge of excavation	0.436	0.440	0.436	0.437	0.436	0.437	0.438	0.439
No. 2	2.21m from west edge of excavation	0.433	0.432	0.431	0.434	0.435	0.436	0.437	0.436
No. 3	4.4m from west edge of excavation	0.435	0.432	0.435	0.435	0.436	0.436	0.437	0.437

Notes:

Set @ 0.2300 in/µs.

CORROSION SERVICE

Bell Hole Examination

7) Cathodic Protection of Pipe

Is there a CP system? (•) Yes ( ) No   Is it functioning? (•) Yes ( ) No   Type of System: Impressed Current

System Output:

Rectifier / Test Post No.	Protected Pipeline	Voltage (V)	Current (A)	Taps
R 271	Trafalgar Line	2.54	0.25	16%
R 191	Dawn Station Piping	11.4	14.2	C-2, F-3
R 190	Dawn Station Piping	9.5	6.7	C-2, F-5
R 272	Dawn Station Piping	47.2	3.3	26%
R 40	8" London Lines	23.7	24.1	C-3, F-1
R 30	Dawn West Lines	18.6	26.4	-
R 131	5985 Pool Line	22	25.2	C-B, F-4
R 192	Dawn Station Piping	7.5	9.9	C-2, F-4
R 224	Dawn Station Piping	10.1	19.3	C-B, C-3
R 135	156 Pool Lines	14	26	C-B, F-1
R 102	Trafalgar Lines	7.5	3.4	C-B, F-3
R 17	Booth Creek Pool	9	3	45%
R 18	Booth Creek Pool	13	10	C-3, F-2
R 200	Dawn Station Piping	10	13	C-B, F-3
R 274	Dawn Station Piping	26	6.9	C-4, F-1
R 278	Dawn Station Piping	27	9	C-D, F-4

Output of Anodes in TS :   U/S of Excavation: N/A   D/S of Excavation: N/A

DC Potentials at Excavation Site

POTENTIAL in mV (•) CSE ( ) SRE ( ) ZRE	At Grade	1/2 Way	At Pipe Depth (Low IR Drop)
Upstream[1] Side of Excavation	-1479	-1482	-1466
Downstream Side of Excavation	-1490	-1498	-1493

[1]Upstream is according to chainage.

AC Potentials at Excavation Site

U/S side of Excavation: 0.15 Volts AC   D/S side of Excavation: 0.14 Volts AC

Is there a DC transit system nearby? No   Distance: -

Are there High Voltage AC lines nearby? No   Distance: -

Notes:

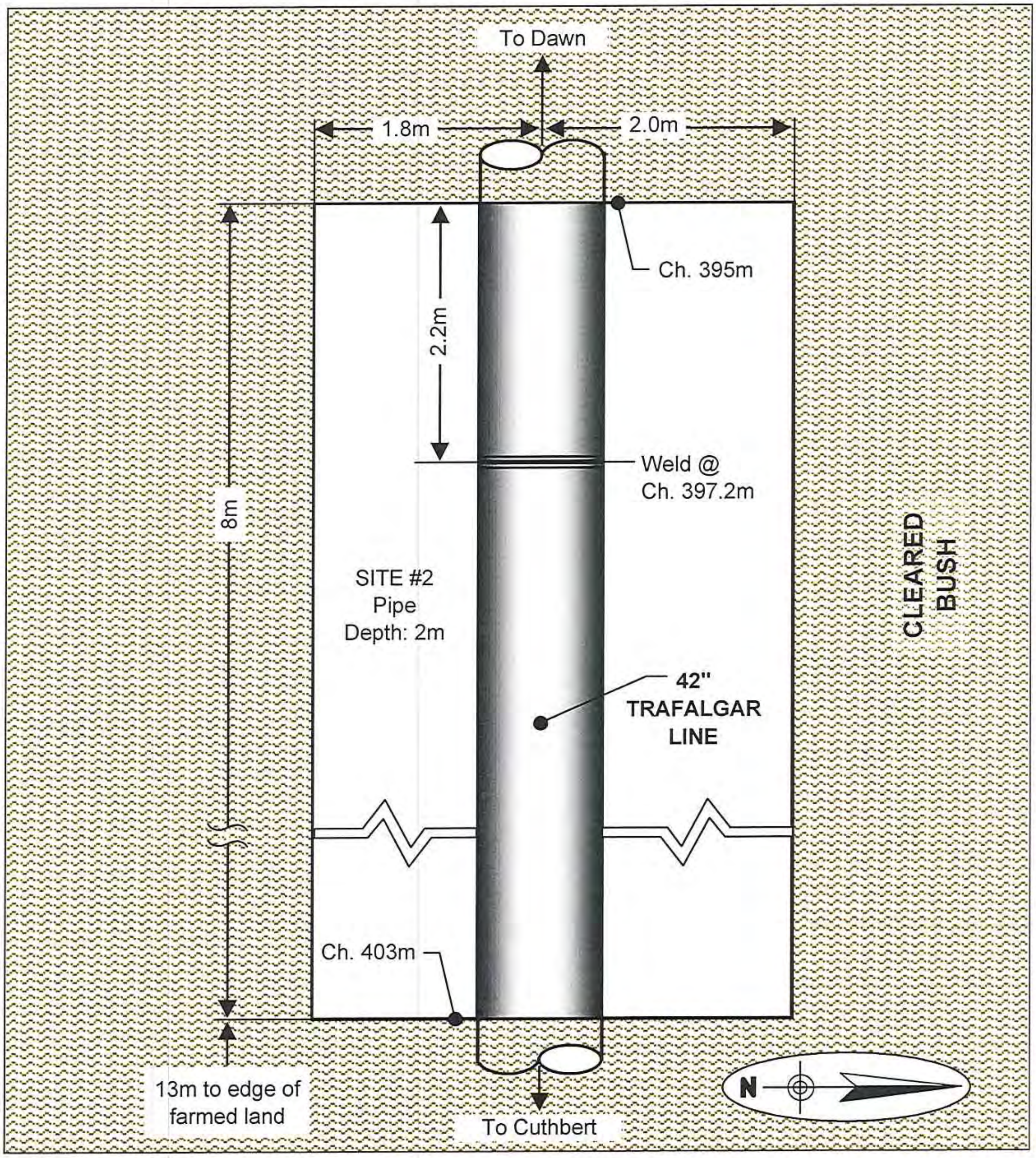
CORROSION SERVICE

Bell Hole Examination

8) Sketch of Excavation Site and Measurement Locations

NOTE:

Include dimensions of excavation, distance to nearest aboveground structure, bends, crossing structures, and north arrow. Measure and record chainages of excavation limits and any anomalies found at site.



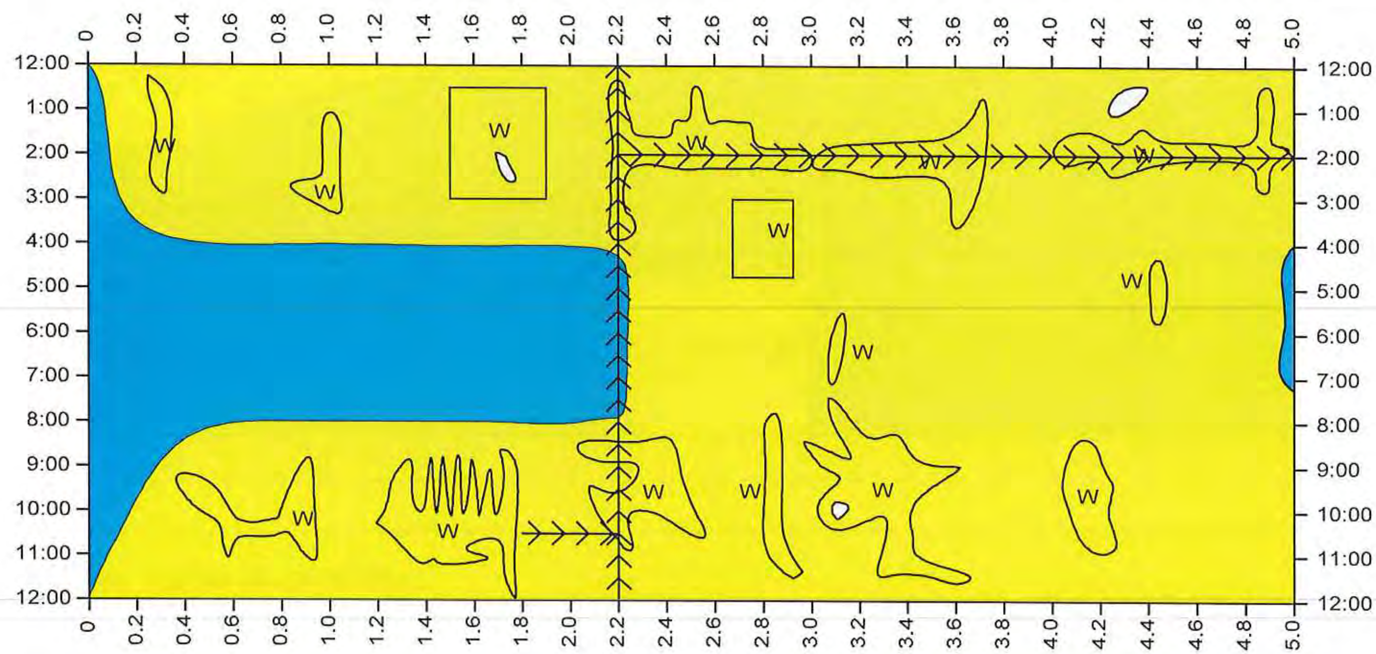
CORROSION SERVICE

Bell Hole Examination

9) Coating Inspection Map

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

Chainage: 399m
Site: 2



LEGEND

Buried Pipe (not exposed)
Denso Tape
Epoxy Coating
Coating Defect (Bare Pipe)
Polyken Tape*
*poor adhesion at overlap
W Wrinkle in Coating
Existing weld

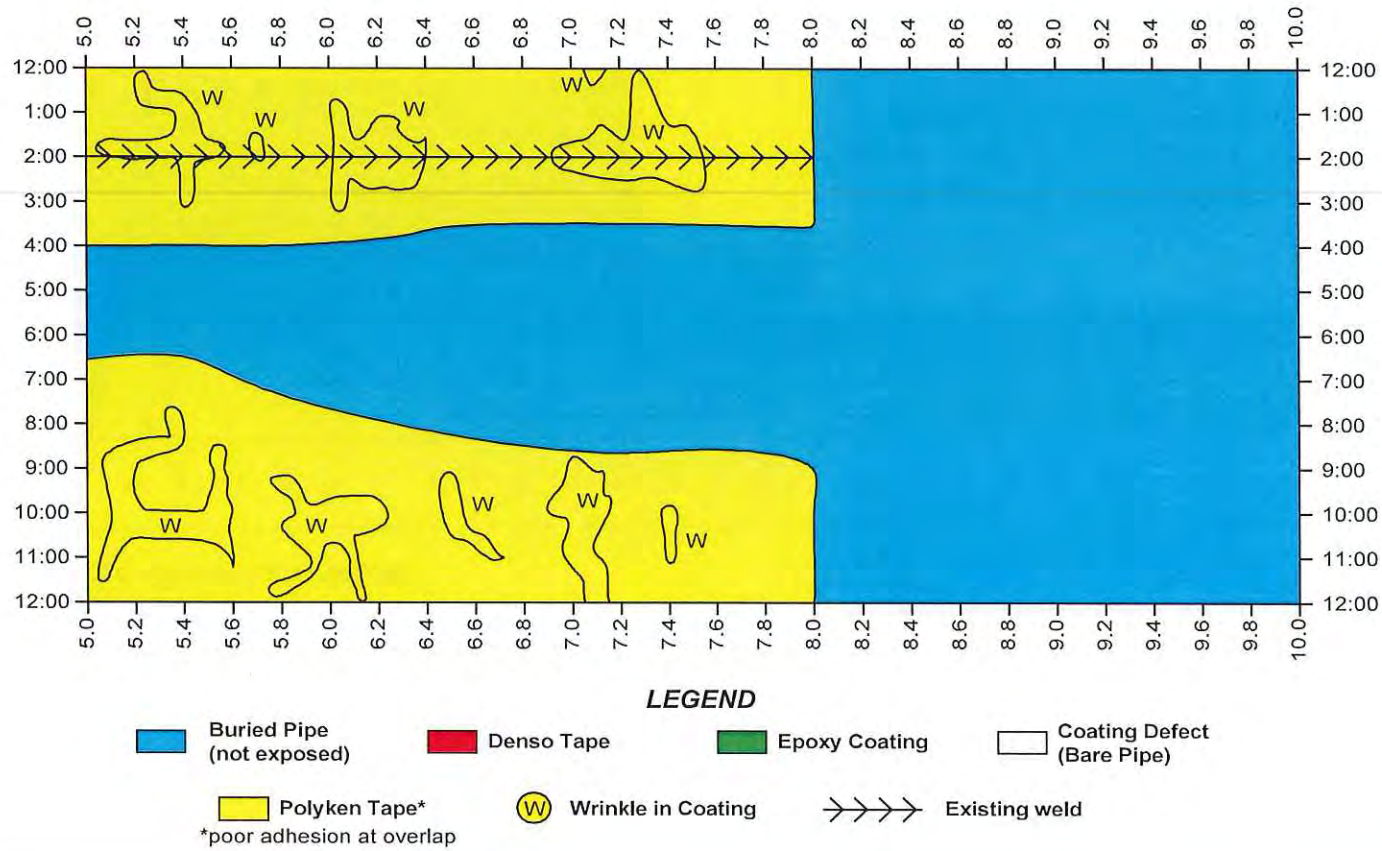
CORROSION SERVICE

Bell Hole Examination

9) Coating Inspection Map Cont'd

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

Chainage: 399m
Site: 2



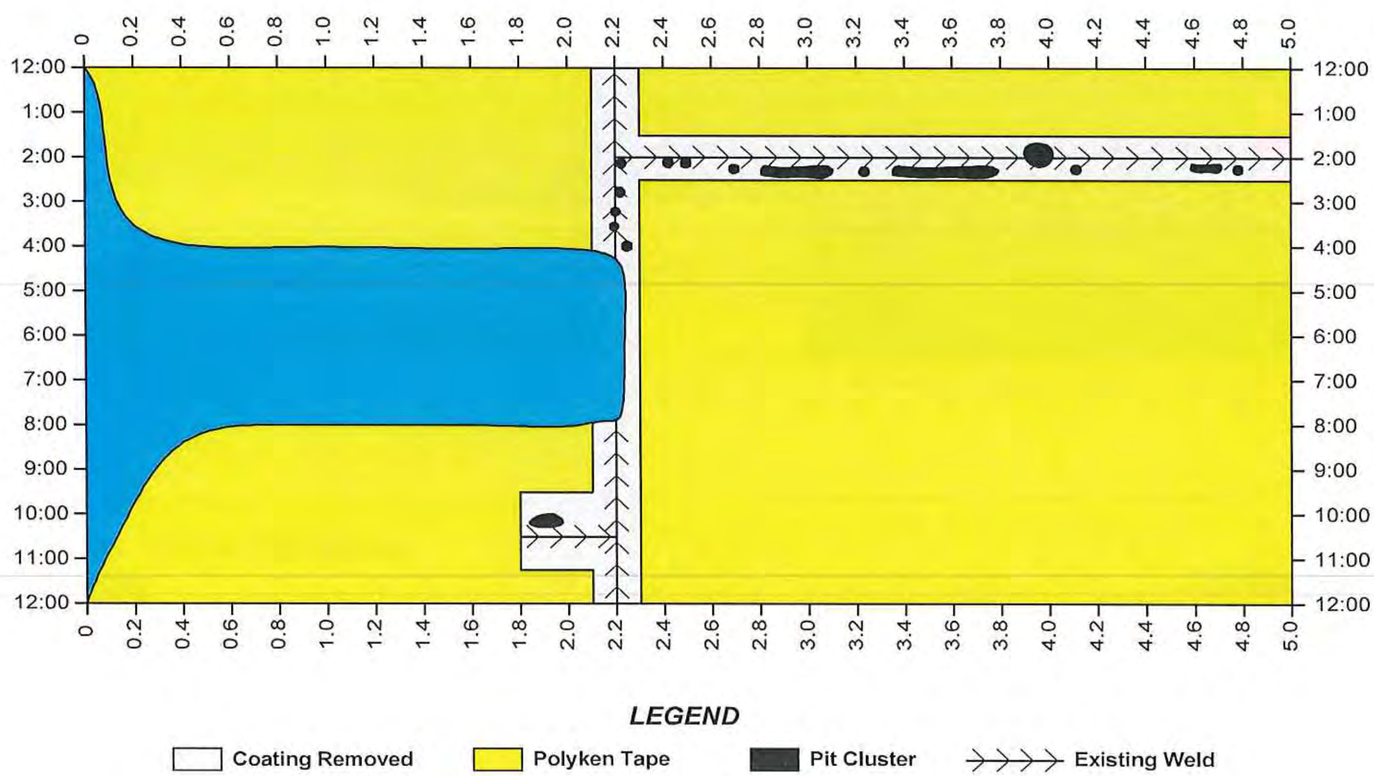
CORROSION SERVICE

Bell Hole Examination

10) Corrosion Grid Map

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

Chainage: 399m
Site: 2



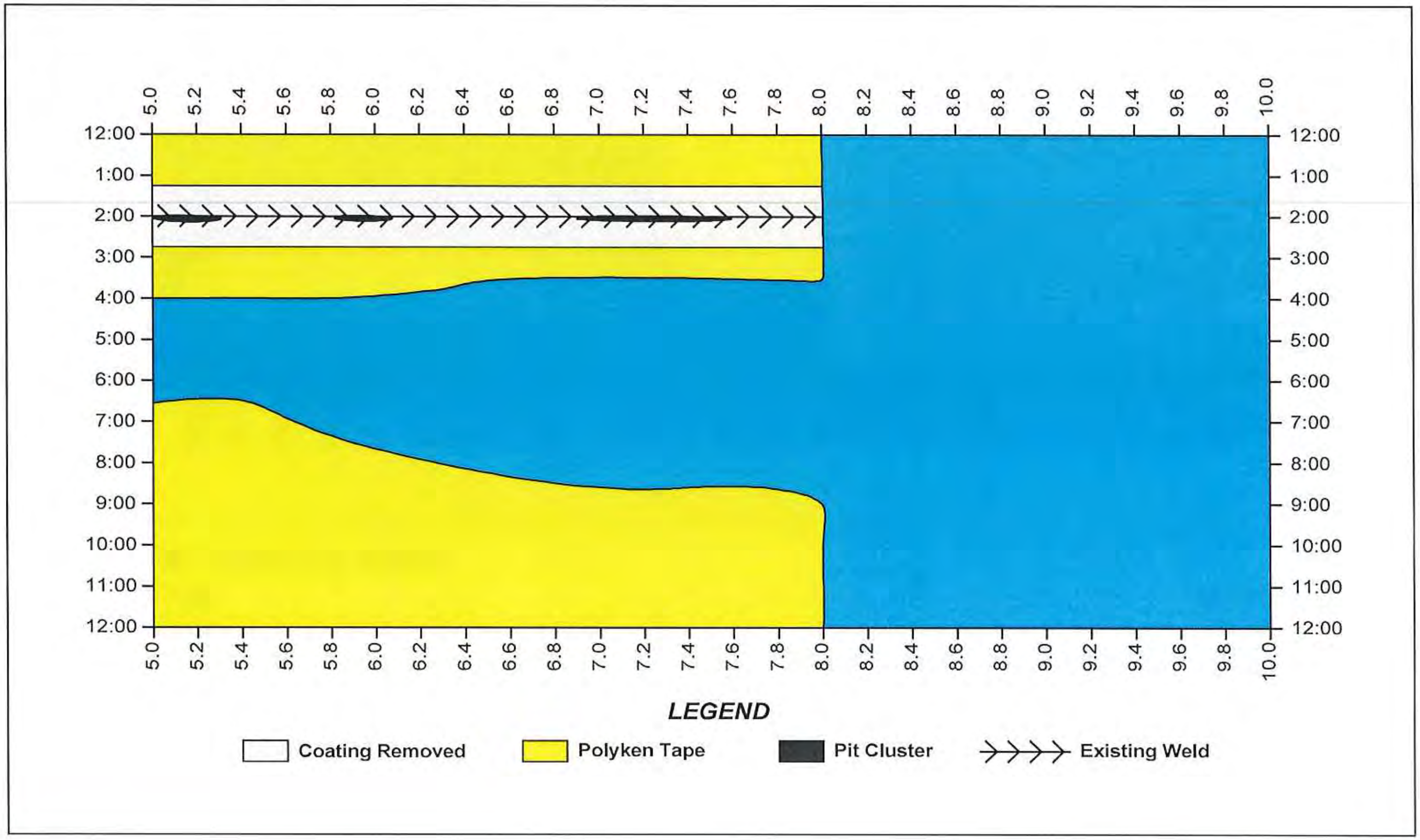
CORROSION SERVICE

Bell Hole Examination

10) Corrosion Grid Map Cont'd

Union Gas Ltd.
42" Trafalgar - Dawn to Cuthbert

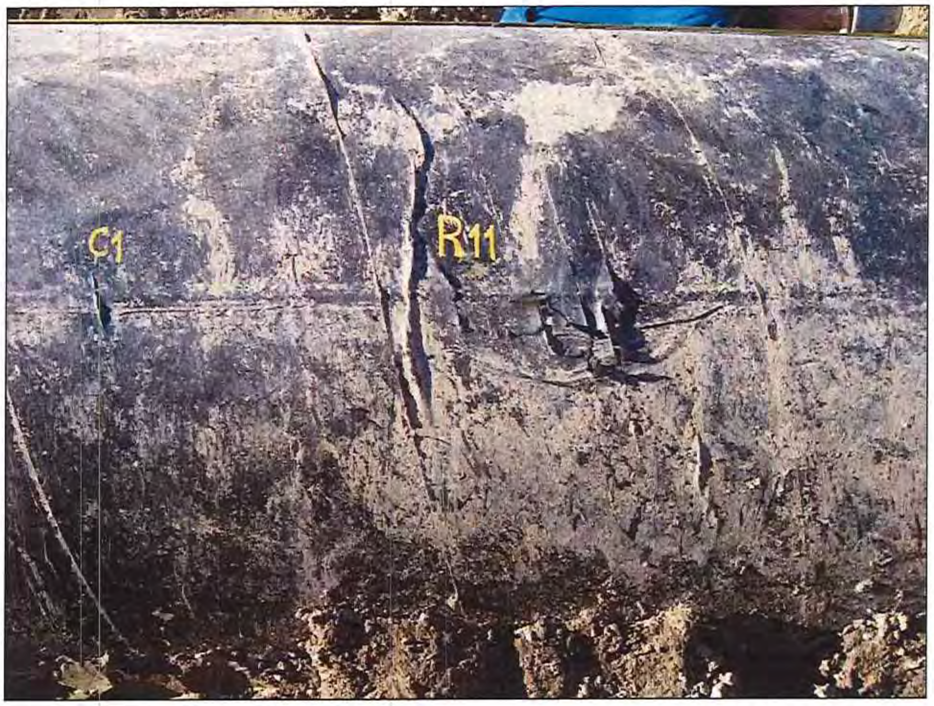
Chainage: 399m
Site: 2



SITE 2 - PHOTOGRAPHS

Photograph 1 • Site 2. General View. Looking West.

Photograph 2 • Site 2. Open Trench. General View. Looking West.



Photograph 3 • Site 2. Disbonded Coating at Longitudinal Weld. Looking North – 01 (East).

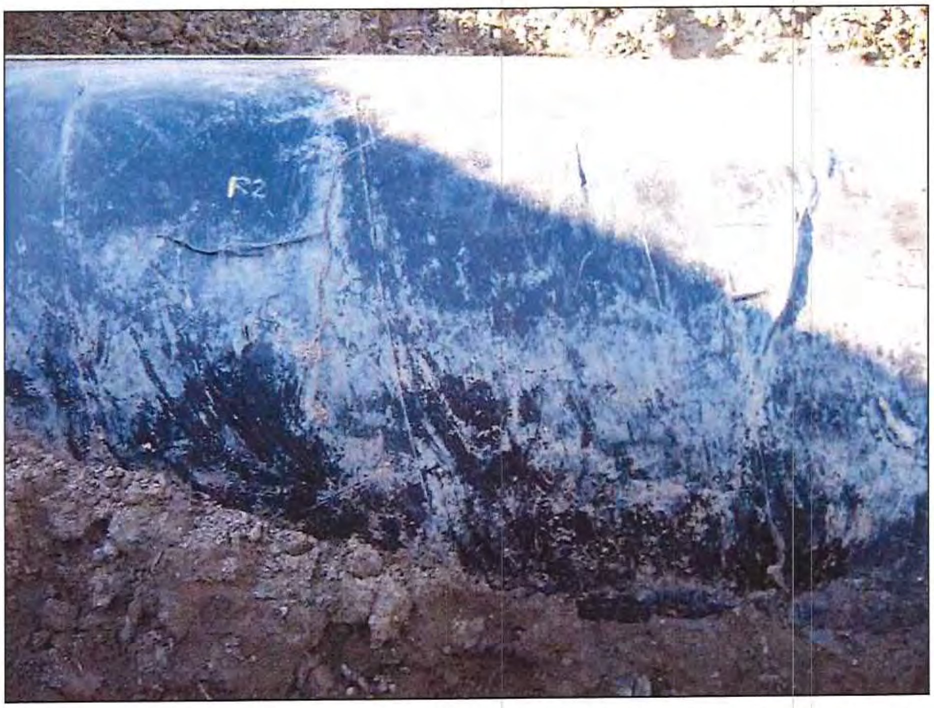
Photograph 4 • Site 2. Disbonded Coating at Longitudinal Weld. Looking North – 02.

Photograph 5 • Site 2. Disbonded Coating at Longitudinal Weld. Looking North – 03.

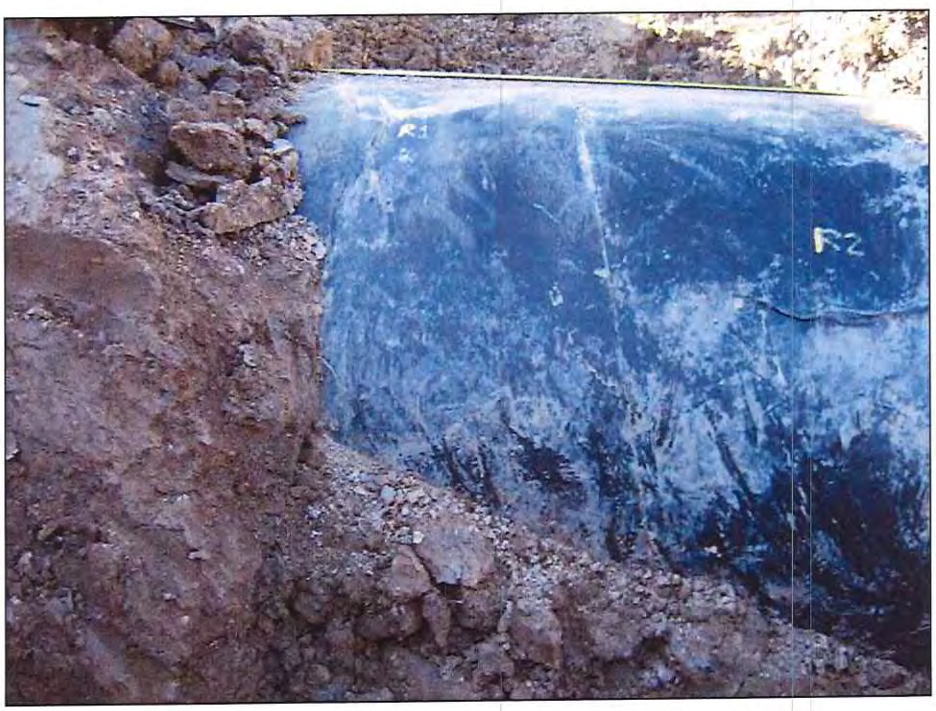
Photograph 6 • Site 2. Disbonded Coating at Longitudinal Weld. Looking North – 04.

Photograph 7 • Site 2. Disbonded Coating at Longitudinal Weld. Looking North – 05.

Photograph 8 • Site 2. Disbonded Coating at Longitudinal Weld. Looking North – 06.

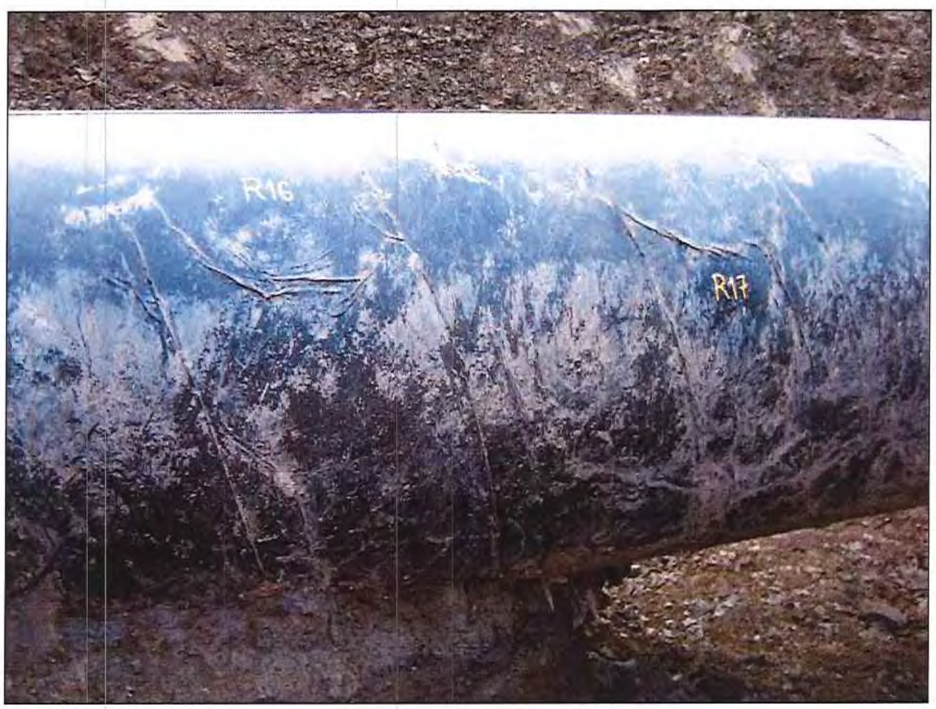


Photograph 9 • Site 2. Disbonded Coating at Longitudinal Weld. Looking North – 07.

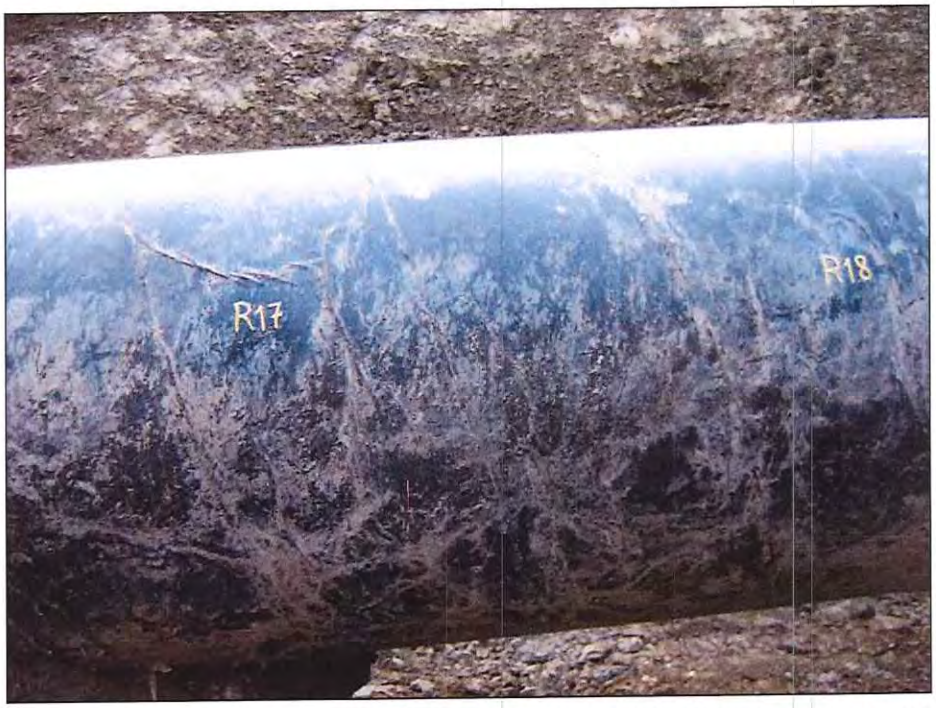


Photograph 10 • Site 2. Disbonded Coating at Longitudinal Weld.
Looking North – 08 (West).

Photograph 11 • Site 2. Disbonded Coating at Longitudinal Weld. Looking South – 01 (East).

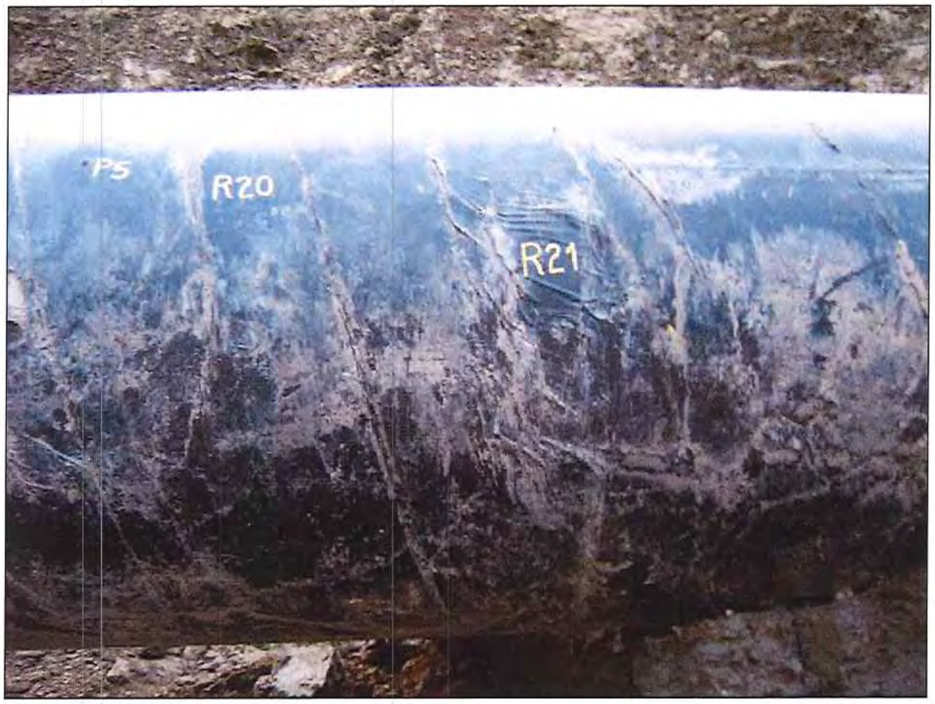


Photograph 12 • Site 2. Disbonded Coating at Longitudinal Weld. Looking South – 02.



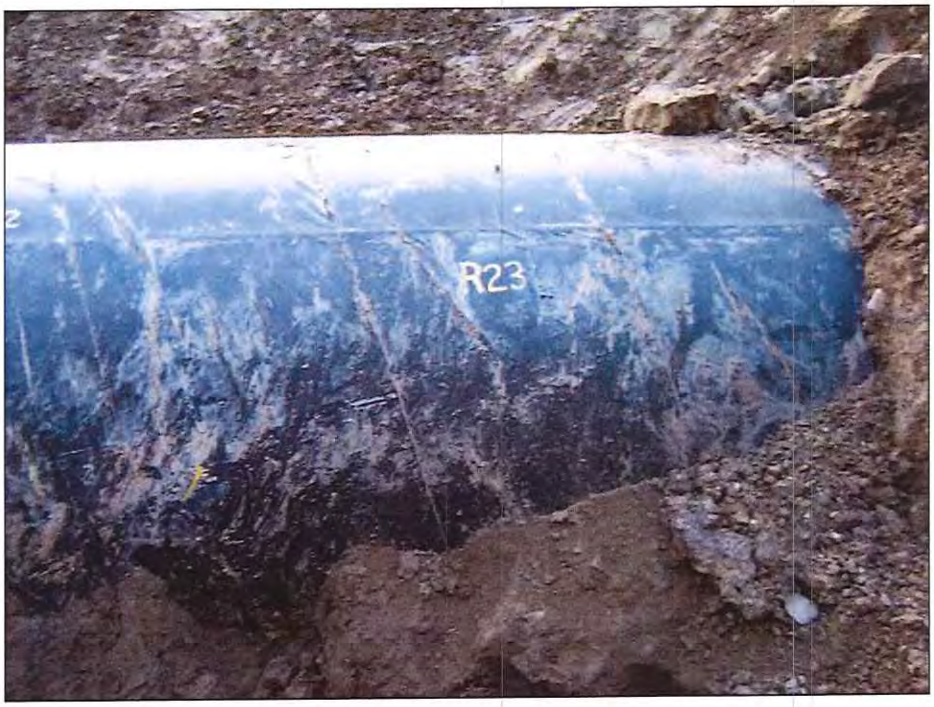
Photograph 13 • Site 2. Disbonded Coating at Longitudinal Weld. Looking South – 03.

Photograph 14 • Site 2. Disbonded Coating at Longitudinal Weld. Looking South – 04.

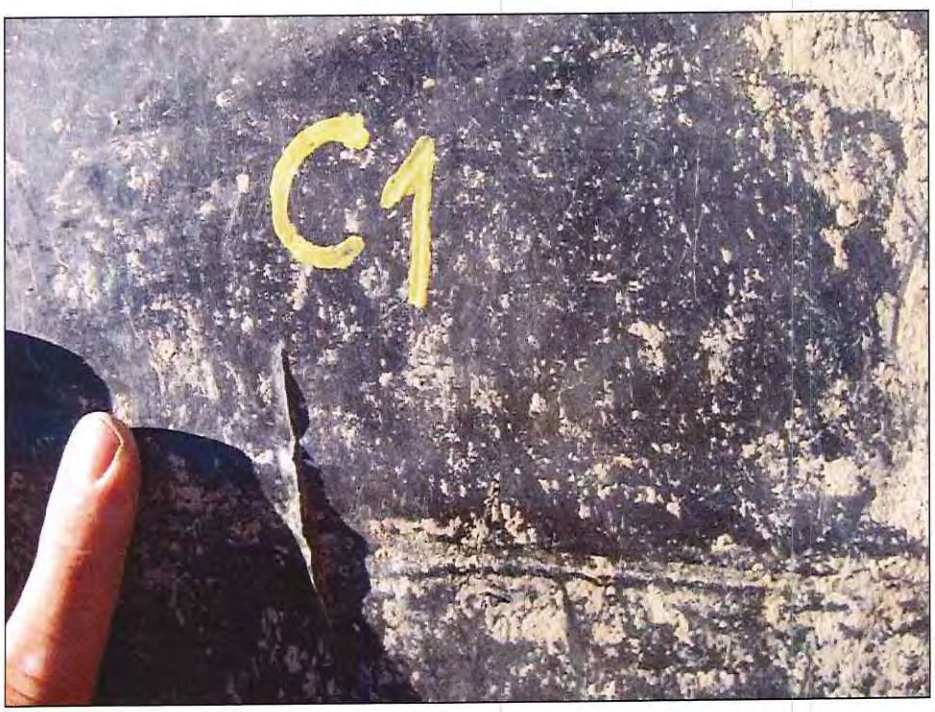


Photograph 15 • Site 2. Disbonded Coating at Longitudinal Weld. Looking South – 05.

Photograph 16 • Site 2. Disbonded Coating at Longitudinal Weld. Looking South – 06.



Photograph 17 • Site 2. Disbonded Coating at Longitudinal Weld. Looking South – 07 (West).



Photograph 18 • Site 2. Coating Damage. Sample of Coating Cut (C1).

Photograph 19 • Site 2. Sample of Coating Damage by Locating Probe (P2).

Photograph 20 • Site 2. Coating Damage. Sample of Disbonded Coating (R5).

Photograph 21 • Site 2. Pipe Exposed at Longitudinal Weld.

Photograph 22 • Site 2. Pipe Exposed at Girth Weld.

Photograph 23 • Site 2. Pipe Exposed. Close View.

Photograph 24 • Site 2. Sample of Shallow Pit (R12 – Pit #1).

Photograph 25 • Site 2. Sample of Shallow Pits (R12 – Pit #'s 2, 3 & 4).

CORROSION SERVICE

APPENDIX B

UGL Integrity Calculations

From: Ron Grozelle [mailto:rgrozelle@spectraenergy.com]
Sent: Tuesday, February 20, 2007 8:38 AM
To: ssegall@corrosionservice.com
Cc: Rod Reid
Subject: NPS-42 - Dawn to Cuthbert Rd

Hi Sorin,

Rod had asked me to take a look at the corrosion items indicated in your report - "Integrity Assessment of the UNION GAS 42" TRAFALGAR LINE Dawn Plant-Cuthbert Road" report, Results of Bell Hole Examination Technical Note #2.

On page 18 of this report - 5.0 Conclusion there is reference that - *"The maximum pit growth after 10 more years of exposure (i.e. in 20015) would not be expected to exceed 6 mils for a total depth of 76 mils".*

The original assessment based on field measurements by Acuren indicated that the maximum length of corrosion cluster was measured to be 395 mm, and depth of 1.50 mm (59 mils) or 13% of wall thickness. This was deemed to be acceptable for continued service at the current MOP of the system.

Based on your prediction that the projected growth of 6.0 mils from approximately 70 mils to 76 mils to year 2015, an analysis was completed to assess the suitability of service for the next 10 years.

The analysis was completed using the following parameters:

Depth		Length	Calculated Design Pres.		MOP
(mm)	(mils)	(mm)	(Kpa)	(psi)	
1.78	70	500	6554	950	6160
2.08	82	500	6511	944	6160
1.78	70	1000	6450	935	6160
2.08	82	1000	6402	928	6160

This would indicate that the system would be acceptable for continued service given the above parameters. I have attached a chart which provides additional calculations showing the maximum depths for both the 1000mm and 500 mm length corrosion lengths.

Summary of Burst Pressure.xls (This file has been reproduced on Page 4B-2)

Note: this date only applies for the parameters used, if corrosion rates vary then a reassessment will be required.

If you have any questions please contact me.

Ron Grozelle, P.Eng.,
Senior Pipeline Engineer
Operations Technical Support
Pipeline Engineering
Ph: 1-519-436-5247
Cell: 1-519-365-0713
Fax: 1-519-436-5292
e-mail: rgrozelle@uniongas.com

CORROSION SERVICE

Integrity Assessment of 42" Trafalgar Line
App. B • UGL Integrity Calculations

FROM: "SUMMARY OF BURST PRESSURE.XLS"

NPS-42 - Dawn to Cuthbert

NPS-42	1067	mm
MOP	6160	Kpa

Grade	414	Mpa
Wall thickness	11.2	mm

DEPTH (MILS)	DEPTH (MM)	% DEPTH	LENGTH 1000 MM				LENGTH 500 MM			
			Max Length (mm)	Burst Pres B31Gmod	Safety Factor	Design Pres	Max Length (mm)	Burst Pres B31Gmod	Safety Factor	Design Pres
70	1.78	16%	1000	8958	1.45	6450	500	9103	1.48	6554
76	1.93	17%	1000	8891	1.44	6402	500	9043	1.47	6511
82	2.08	19%	1000	8756	1.42	6304	500	8983	1.46	6468
118	3.00	27%	1000	8140	1.32	5861	500	8366	1.36	6024
158	4.01	36%	1000	7438	1.21	5355	500	7719	1.25	5558
197	5.00	45%	1000	6717	1.09	4836	500	7043	1.14	5071
237	6.02	54%	1000	5977	0.97	4303	500	6332	1.03	4559
270	6.86	61%	1000	5370	0.87	3866	500	5739	0.93	4132

Safety Factor = Pbust/MOP
Resulting Design Pressure = Pburst X (0.8 X 0.9)

Date: February 19, 2007

CORROSION SERVICE

Integrity Assessment of 42" Trafalgar Line
App. B • UGL Integrity Calculations

NPS-42 - Dawn to Cuthbert

NPS-42	1067	mm
MOP	6160	Kpa
Grade	414	Mpa
Wall thickness	11.2	mm

			Length 1000 mm				Length 500 mm			
Depth (mils)	Depth (mm)	% depth	Max Length (mm)	Burst Pres B31Gmod	Safety Factor	Design Pres	Max Length (mm)	Burst Pres B31Gmod	Safety Factor	Design Pres
70	1.78	16%	1000	8958	1.45	6450	500	9103	1.48	6554
76	1.93	17%	1000	8891	1.44	6402	500	9043	1.47	6511
82	2.08	19%	1000	8756	1.42	6304	500	8983	1.46	6468
118	3.00	27%	1000	8140	1.32	5861	500	8366	1.36	6024
158	4.01	36%	1000	7438	1.21	5355	500	7719	1.25	5558
197	5.00	45%	1000	6717	1.09	4836	500	7043	1.14	5071
237	6.02	54%	1000	5977	0.97	4303	500	6332	1.03	4559
270	6.86	61%	1000	5370	0.87	3866	500	5739	0.93	4132
		0%	1000		0.00	0	500		0.00	0
		0%	1000		0.00	0	500		0.00	0

Safety Factor = Pbust/MOP

Resulting Design Pressure = Pburst X (0.8 X 0.9)

Date: February 19, 2007

EXTERNAL CORROSION DIRECT ASSESSMENT REPORT
STEP 2: INDIRECT INSPECTION REPORT

FOR
ENBRIDGE GAS INC.

26”, 34” & 42” TRAFALGAR LINES
DAWN PLANT TO CUTHBERT RD.

Prepared for:
Brad Jefferies, CET
Integrity Management Dept.

Prepared By:
Corrpro Canada, Inc.
Mississauga, ON

Certificate of Authorization No.:
100174695

CORRPRO DOCUMENT No.: 1521-0279-ENB-STEP2-012-1

1	14-Mar-21	-	Mahmoud Kenawi, Engineer I	Anthony Khoury, P.Eng. NACE CP1, CIP2 Engineer II	Stephen Dueck, NACE CP2 Engineer II
REV	**DATE (DD-MMM-YY)**	**COMMENTS**	**ORIGINATOR**	**REVIEWER**	**APPROVER**

Originated by:

Mahmoud Kenawi, EIT
Email: mkenawi@aegion.com

Reviewed by:

Anthony Khoury, P.Eng.,
NACE CP1, CIP2
Email: akhoury@aegion.com

Approved by:

Stephen Dueck, NACE CP2
Engineer II
Email: sdueck@aegion.com

REVISION LOG

REV	REVISION / CHANGE DESCRIPTION
0	Issued for Review

Table of Contents

Appendices

1.0 EXECUTIVE SUMMARY

The primary objectives of ECDA surveys are to detect areas of possible coating defects, assess their severity and identify areas on the pipeline where the probability of corrosion activity is elevated. These objectives were achieved through the collection, processing and analysis of field data. Indirect inspection surveys were completed in the fall of 2020 by Corrpro Canada, Inc. (Corrpro) on the three (3) Trafalgar Lines (26", 34", and 42") which run in parallel over approximately 670m from the Dawn Plant to the Cuthbert Station. The data processing and indication prioritization methods applied in this report are based on methodology recommended in NACE SP0502-2010 - Pipeline External Corrosion Direct Assessment (ECDA) Methodology, in conjunction with Enbridge's ECDA guidelines.

Note that the previous ECDA surveys completed in 2005 showed that while the coating on the 26" and 34" lines appeared to be in fair to poor condition with little to no corrosion on the surface of the pipe, the 42" pipe showed areas of Polyken disbondment with minor to moderate pitting corrosion with up to 16% wall loss (Trapped water under coating had a pH of 7). It was also predicted that further pitting would not exceed another 10 mils (for a total of 80mils). until year 2025

As planned in the pre-assessment step of the ECDA process, the surveys consisted of a Close Interval Potential Survey (CIPS) and a DC Voltage Gradient (DCVG) survey. Note that independent DCVG surveys were conducted for all three (3) lines. Depth of Cover (DOC) readings were collected periodically, and soil resistivity measurements were taken at multiple locations along the subject pipeline to allow for accurate analysis and prioritization of the anomalies detected.

The following conclusions were established in Step 2 of the ECDA process for the Trafalgar Lines:

- The CIPS data indicate that the entirety of the surveyed lines is adequately protected. All pipe to soil potential readings collected satisfy the minimum protection criterion established by NACE.

- The DCVG surveys data revealed eight (8) “Minor” indications in total across all three (3) pipelines; all prioritized as “Suitable for Monitoring”.

- Due to the low number of indications detected and based on previous studies conducted on the lines in 2005, the ECDA regions were redefined to treat all three lines as one single region.

It should be noted that the results of this survey present the CP levels and voltage gradients at the time of the survey and could change over time.

2.0 RECOMMENDATIONS

As per Section 5.3.4.2, “If an ECDA region contains monitored indications and the ECDA region did not contain any immediate or scheduled indications, one direct examination (DE) is required in the ECDA region at the most severe indication.” Furthermore, in accordance with Section 6.7.2 of the same standard, “At least one additional direct examination at a randomly selected location shall be performed to provide additional confirmation that the ECDA process has been successful.”. It is important to note that the previous ECDA conducted in 2005 recorded 16% wall loss under disbonded Polyken (trapped water pH of 7) for the 42” Line. Therefore, the prior history of corrosion for the 42” Line is set to Moderate.

➔ **Direct Examination #1**: Anomaly #5, “Minor DCVG”, indication detected on the 42” Trafalgar line, prioritized as “Suitable for Monitoring”. Approx. chainage 53.3 (42.716211, -82.216716) with an estimated pipe depth of 2.2m. DCVG %IR = 25.4%, CIPS_OFF = -1127.2mV$_{CSE}$. Minor coating damage with minor or no corrosion is expected at this location.

➔ **Direct Examinations #2 and #3 (In lieu of indirect inspection surveys/Validation):** Additional direct examinations are needed to assess the risk of shielded corrosion activity on the 42” pipeline, which has Polyken coating applied on its entirety. Because of the known poor adhesion performance of this type of coating, and since indirect inspection tools are not capable of assessing shielded corrosion activity, additional direct examinations are recommended at a minimum of two (2) random locations to inspect for possible Polyken coating disbondment. Note, such additional Direct Examination digs may also serve as Validation digs.

Finally, it is recommended to set the reassessment interval to ten (10) years. Note, this interval may be modified with respect to results obtained in Steps 3 and 4 of the ECDA process.

3.0 SUMMARY OF DEFICIENCIES

Deficiencies are data anomalies or "indications" in the processed survey data; the anomaly prioritization process is based on NACE SP0502-2010 in conjunction with Enbridge's ECDA guidelines.

Table 3-1 lists all the anomalies detected by the indirect inspection tools along with their assigned prioritization.

Table 3-1: LIST OF INDICATIONS DETECTED

Trafalgar Pipeline Diameter (in)	Anomaly Label	Approx. Chainage (m)	DOC (m)	Potentials		Coating	Prioritization
				CIPS_ON (mV)	CIPS_OFF (mV)	DCVG %IR	
26"	**1: Minor DCVG**	353.2	1.6	-1223	-1175	6.7%	**Suitable for Monitoring**
34"	**2: Minor DCVG**	631.2	1.3	-1262	-1221	21.7%	**Suitable for Monitoring**
34"	**3: Minor DCVG**	665.6	1.1	-1245	-1208	8.6%	**Suitable for Monitoring**
42"	**4: Minor DCVG/Fence**	42.0	2.2	-1195	-1121	24.5%	**Suitable for Monitoring**
42"	**5: Minor DCVG**	53.3	2.2	-1200	-1127	25.4%	**Suitable for Monitoring**
42"	**6: Minor DCVG**	58.1	1.7	-1203	-1129	18.5%	**Suitable for Monitoring**
42"	**7: Minor DCVG**	89.4	1.7	-1210	-1141	7.1%	**Suitable for Monitoring**
42"	**8: Minor DCVG**	124.0	1.7	-1422	-1128	7.2%	**Suitable for Monitoring**

4.0 INDIRECT INSPECTION DATA ANALYSIS

As stated in the pre-assessment report for the Trafalgar Lines, the indirect inspection tools selected were a close interval potential survey (CIPS) in conjunction with a direct current voltage gradient (DCVG) survey. Due to the small potential shift, independent DCVG surveys were necessary for all three (3) lines. Other integrity data collected for this ECDA include rectifier outputs, waveform frequency analysis, pipe-to-soil potential readings at points of interest, AC voltages and DOC readings. It should be noted that details on the technology and calibration certificates of the different equipment and tools used can be found in Appendix 3.

4.1 RECTIFIERS

Table 4-1 lists all rectifiers which were synchronized to interrupt during the survey, along with their measured voltage and current outputs.

Table 4-1: INTERRUPTED RECTIFIERS

Rectifier	Voltage (V)	Current (A)
#131	21.6	25.8
#271	6.1	2.8
#190	7.0	6.3
#192	7.2	6.7
#200	6.5	9.5
#224	10.1	13.0
#277	4.3	4.3
#369	9.4	17.1

In order to verify that the lines were free of external residual rectifier DC influence, a digital oscilloscope was utilized to collect pipeline data and post processed using a Fast Fourier analysis. Upon completion of this pipeline frequency test, no 120Hz ripple was found on the line during the "OFF" cycle, indicating that there was no residual DC influence, and all influencing rectifiers are interrupting adequately. A visual representation of this test is depicted in Appendix 2.

4.2 CATHODIC PROTECTION (CIPS)

Cathodic protection (CP) is used to control the external corrosion of buried pipelines by making the surface of a buried pipeline the cathode of an electrochemical cell. NACE provides a defined relationship between 'True OFF' pipe to soil potentials and the propensity for corrosion. Table 4-2 below shows the CP thresholds considered for determining indication severity. The criterion implemented for assessing the effectiveness of a pipelines cathodic protection (CP) system is derived from the NACE Standard Practice SP0169-2013 and based on the Enbridge ECDA standard.

Table 4-2: CATHODIC PROTECTION INDICATION THRESHOLDS			
Indirect Inspection Technique	Indication Severity		
	Severe	Moderate	Minor
CP, CIPS	'True OFF' potentials more electro-positive than -799mV	'True OFF' potentials more electro-negative than -800mV but not more than -899mV	'True OFF' potentials more electro-negative than -900mV but not more than -1000mV

As can be observed on the CIPS data charts shown in Appendix 2, all three (3) Trafalgar Lines showed adequate levels of cathodic protection; with all readings satisfying the protection criterion without any CP deficiencies detected.

4.3 COATING ANOMALIES (DCVG)

A pipeline anomaly is any deviation from nominal conditionals in the external coating and wall of a pipe. A coating anomaly is a classification given to any tested segments of pipeline indicating imperfection or defect in the coating. Coating anomalies cannot be referred to as holidays or faults until the pipe is exposed and the holiday or fault is confirmed. This is because phenomena such as interference, shielding, non-homogenous soils or sacrificial anodes directly welded to the pipeline can also cause test responses. Correlating results between the different indirect inspection tools highlights the difference between what appears to be an anode or what is likely a coating holiday. Table 4-3 below shows the coating integrity thresholds considered when processing the data collected in the DCVG survey.

Table 4-3: COATING INDICATION THRESHOLDS			
Indirect Inspection Technique	Indication Severity		
	Severe	Moderate	Minor
Coating, DCVG	> 60%IR; anodic both 'ON' & 'OFF'	60% IR – 35%IR; cathodic 'ON', anodic or neutral 'OFF'	< 35% IR cathodic both 'ON' & 'OFF'

Table 4-4 lists the DCVG indications detected. All eight (8) indications were prioritized as "Suitable for Monitoring".

Table 4-4: COATING DATA ANOMALIES					
Trafalgar Pipeline Diameter (in)	Anomaly Label	Approx. Chainage (m)	DCVG (%IR)	Latitude	Longitude
26"	**1: Minor DCVG**	353.2	6.7%	42.717486	-82.213460
34"	**2: Minor DCVG**	631.2	21.7%	42.718565	-82.210410
34"	**3: Minor DCVG**	665.6	8.6%	42.718629	-82.210098
42"	**4: Minor DCVG/Fence**	42.0	24.5%	42.716163	-82.216840
42"	**5: Minor DCVG**	53.3	25.4%	42.716211	-82.216716
42"	**6: Minor DCVG**	58.1	18.5%	42.716225	-82.216668
42"	**7: Minor DCVG**	89.4	7.1%	42.716346	-82.216326
42"	**8: Minor DCVG**	124.0	7.2%	42.716480	-82.215939

It should be noted that all possible anomalies are tested and filtered as per NACE TM109-2009 and SP0207-2007, to only present anomalies that cannot be ruled out. This process involves removing scatter, adjusting for interference, removing magnetic field distortion, spanning gradients and using measurements from nearby features to rule out measurement errors.

Note that the previous ECDA surveys completed in 2005 showed that while the coating on the 26" and 34" lines appeared to be in fair to poor condition with little to no corrosion on the surface of the pipe, the 42" pipe showed areas of Polyken disbondment with minor to moderate pitting corrosion with up to 16% wall loss. It was also predicted that further pitting would not exceed another 10 mils until year 2025. This prediction was based on the few direct examinations completed on the 42” line in 2005. As Polyken coating has a known poor adhesion performance record, its presence can affect ECDA feasibility because indirect inspection tools are not capable of assessing shielded corrosion activity. Additional direct examinations must be recommended at several locations to address the concern for possible corrosion activity under Polyken disbondment.

4.4 GEOTECHNICAL ANOMALIES

CSA Standard Z662-15 can be consulted regarding Depth of Cover (DOC) requirements for pipelines. This is the primary code governing the operation of oil and gas pipelines in Canada. In most cases, the minimum DOC requirement is 0.60m (24in), or 1.2m (48in) under roads. During the field survey, DOC data was collected at a minimum of every 40m and no areas of low cover were detected.

4.5 TEST POST READINGS AND SOIL RESISTIVITY

Table 4-5 lists pipe-to-soil DC and AC potential readings measured by the Corrpro field technicians at test stations and risers. This data provides insight into the local cathodic protection levels, as well as information on safety risks and the risks of AC corrosion.

Table 4-5: TEST POINT READINGS

TP#	Lat	Long	ON (mV)	OFF (mV)	AC (V)	Comments
TP # 1	42.716064	-82.217315	-1209	-1116	0.32	Dawn North Plant (10G-374)
TP # 2	42.716200	-82.216900	-1220	-1160	0.04	Coupon Test station
TP # 3	42.719103	-82.208616	-1220	-1115	0.20	Cuthbert valve site (10G-303V)

The risks associated with HVAC interference at any point on the structure can be assessed using AC structure-to-soil potentials. Firstly, to secure personnel from shock, measured AC voltages to ground have been set by regulatory bodies to a maximum of 15VAC. Second, the propensity of AC corrosion can be assessed by using worst-case assumptions, such as the presence of a small coating holiday with the highest AC measured in combination with lowest soil resistivity noted. This is discussed further in Section 4.7.

A 4-pin Wenner test was conducted at several locations. Determining soil resistivity is critical in prioritizing each anomaly indication. Generally, lower soil resistivities (less than 2000 Ω-cm) are increasingly corrosive; this can be accounted for in anomaly prioritization by increasing the severity of CIPS and DCVG indications accordingly. Table 4-6 lists the soil resistivities measured.

Table 4-6: SOIL RESISTIVITY

Location	Latitude	Longitude	Soil Resistivity (Ω-cm)			Corrosivity/ Comments
			Depth 1m	Depth 3m	Depth 5m	
Dawn Plant	47.508178	-79.757079	2820	1800	2060	Moderate
Near Chainage 200m	42.716793	-82.215187	1480	1660	1900	Moderate
Near Chainage 500m	42.717874	-82.212071	1200	1660	2100	Moderate
Cuthbert Road	42.719103	-82.208616	1650	1560	1740	Moderate

4.6 INTERFERENCE (DATA LOGGERS)

In order to measure if any time dependant interference (temporal, tidal or DC traction) existed on this pipeline, a stationary data logger (SDL) was set up at the North Riser (Tee with Haileybury Lateral) and CP data was measured continuously at this location as the pipeline survey progressed. No time dependant interference was observed on the pipelines surveyed based on SDL data.

4.7 AC INDUCED CORROSION RISK ASSESSMENT

AC voltage data is used in conjunction with the soil resistivities measured to estimate the risk of AC induced corrosion. Higher induced AC voltages with lower resistivity soils present higher risk for AC induced corrosion. As stated in the Enbridge ECDA standard, current densities below 50 A/m^2 are to be considered as minor indications, current densities between 50 and 100 A/m^2 are moderate indications, and all current densities above 100 A/m^2 present severe indications. It is important to note that wherever severe AC current densities are estimated, all DCVG indication prioritizations are to be upgraded to "Immediate action required". Furthermore, when current densities exceed 100 A/m^2, excavating short sections should be considered, even without DCVG indications. Note, AC current density was calculated based on a 1cm^2 holiday surface area.

Table 4-7: AC CURRENT DENSITY				
Location	**Soil Resistivity (Ω-cm)**	**Max AC Voltage (V)**	**AC Current Density (A/m^2)**	**Comments**
TP # 1	1800	0.32	**4.01**	Minor / Low risk
TP # 2	1480	0.04	**0.61**	Minor / Low risk
TP # 3	1560	0.91	**2.89**	Minor / Low risk

As shown in Table 4-7, the levels of pipe-to-soil AC potentials and AC current densities on the Cobalt Lateral do not pose a safety threat nor a notable risk of AC induced corrosion. A sample of SDL data collected on September 15th, 2020 is provided in Appendix 2.

4.8 AREAS NOT SURVEYED

No areas were skipped.

5.0 CONCLUSION AND RECOMMENDATIONS

The final step of the indirect inspection data analysis is to rank and prioritize the severity of the deficiency indications collected, and to offer maintenance and direct examination recommendations in accordance to NACE and Enbridge standards. To prioritize indications, NACE SP0502-2010 instructs using the following three-tier classification system:

- **Immediate Action Required (I)** - this priority category includes indications considered as likely to have ongoing corrosion activity and may pose an immediate threat to the pipeline under normal operating conditions. Enbridge's ECDA standard sets the Step 3 response time for such indications to a maximum of 18 months.

- **Scheduled Action Required (S)** - this priority category includes indications considered to likely have ongoing corrosion activity but that, do not pose an immediate threat to the pipeline under normal operating conditions. Enbridge's ECDA standard sets the Step 3 response time for such indications to a maximum of 4 years.

- **Suitable for Monitoring (M)** - this priority category includes indications considered as having the lowest rate of ongoing corrosion activity with no further action required beyond monitoring over following inspections.

Table 5-1 consists of a prioritization guideline based on the Enbridge ECDA standard. It helps correlate data from the different indirect inspection tools to determine the ECDA dig priority level for each anomaly site.

Table 5-1: ECDA DIG CRTIERIA																
Coating Integrity DCVG	Prior History of Corrosion				Cathodic Protection CIPS				DC Interference				AC Current Density			
	SV	MD	MN	NI	SV	MD	MN	NI	SV	MD	MN	NI	SV	MD	MN	NI
Severe (SV)	I	I	S	S	I	S	S	S	I	S	S	S	-	-	-	S
Moderate (MD)	I	S	M	M	S	S	M	M	I	S	M	M	-	-	-	M
Minor (MN)	M	M	M	M	S	M	M	M	I[1]	S	M	M	I[1]	S	M	M

Note 1: As per Enbridge ECDA standard, if severe DC interference or severe current density are detected, consider excavating short sections, even without DCVG indications.

Table 3-1 in Section 3 lists all indications reported on all three (3) Trafalgar Lines from Dawn Plant to Cuthbert Station, along with their respective prioritization level.

Finally, in accordance with Section 5.3.4.2, "If an ECDA region contains monitored indications and the ECDA region did not contain any immediate or scheduled indications, one direct examination is required in the ECDA region at the most severe indication." Furthermore, in accordance with

Section 6.7.2 of the same standard, “At least one additional direct examination at a randomly selected location shall be performed to provide additional confirmation that the ECDA process has been successful.”.

- ➔ **Direct Examination #1**: Anomaly #5, “Minor DCVG”, indication detected on the 42” Trafalgar line, prioritized as “Suitable for Monitoring”. Approx. chainage 53.3 (42.716211, -82.216716) with an estimated pipe depth of 2.2m. DCVG %IR = 25.4%, CIPS_OFF = -1127.2mVCSE. Minor coating damage with minor or no corrosion is expected at this location.
- ➔ **Direct Examinations #2 and #3 (In lieu of indirect inspection surveys/Validation):** Additional direct examinations are needed to assess the risk of shielded corrosion activity on the 42” pipeline, which has Polyken coating applied on its entirety. Because of the known poor adhesion performance of this type of coating, and since indirect inspection tools are not capable of assessing shielded corrosion activity, additional direct examinations are recommended at a minimum of two (2) random locations to inspect for possible Polyken coating disbondment. Note, such additional Direct Examination digs may also serve as Validation digs.
- ➔ It is important to note that the previous ECDA conducted in 2005 recorded 16% wall loss under disbonded Polyken (trapped water pH of 7) for the 42” Line. Therefore, the prior history of corrosion for the 42” Line is set to Moderate.

Finally, it is recommended to set the reassessment interval to ten (10) years. Note, this interval may be modified with respect to results obtained in Steps 3 and 4 of the ECDA process.

6.0 CONTACT INFORMATION

Please contact Corrpro Canada Inc. if you have any questions or require additional information regarding this report.

Corrpro Canada Inc. (Mississauga Office)
7895 Tranmere Dr, E
Mississauga, ON
L5S 1V9
(905) 677-2700
www.corrpro.ca

Anthony Khoury, P.Eng. CP1, CIP2
Engineer II
(416) 550-8953
akhoury@aegion.com

Stephen Dueck, NACE CP2
Engineer II
(416) 220-0144
sdueck@aegion.com

Joe Beutler, NACE CP3
Operations Manager
(416) 791-3682
jbeutler@aegion.com

APPENDIX 1 - SURVEY DATA OVERVIEW

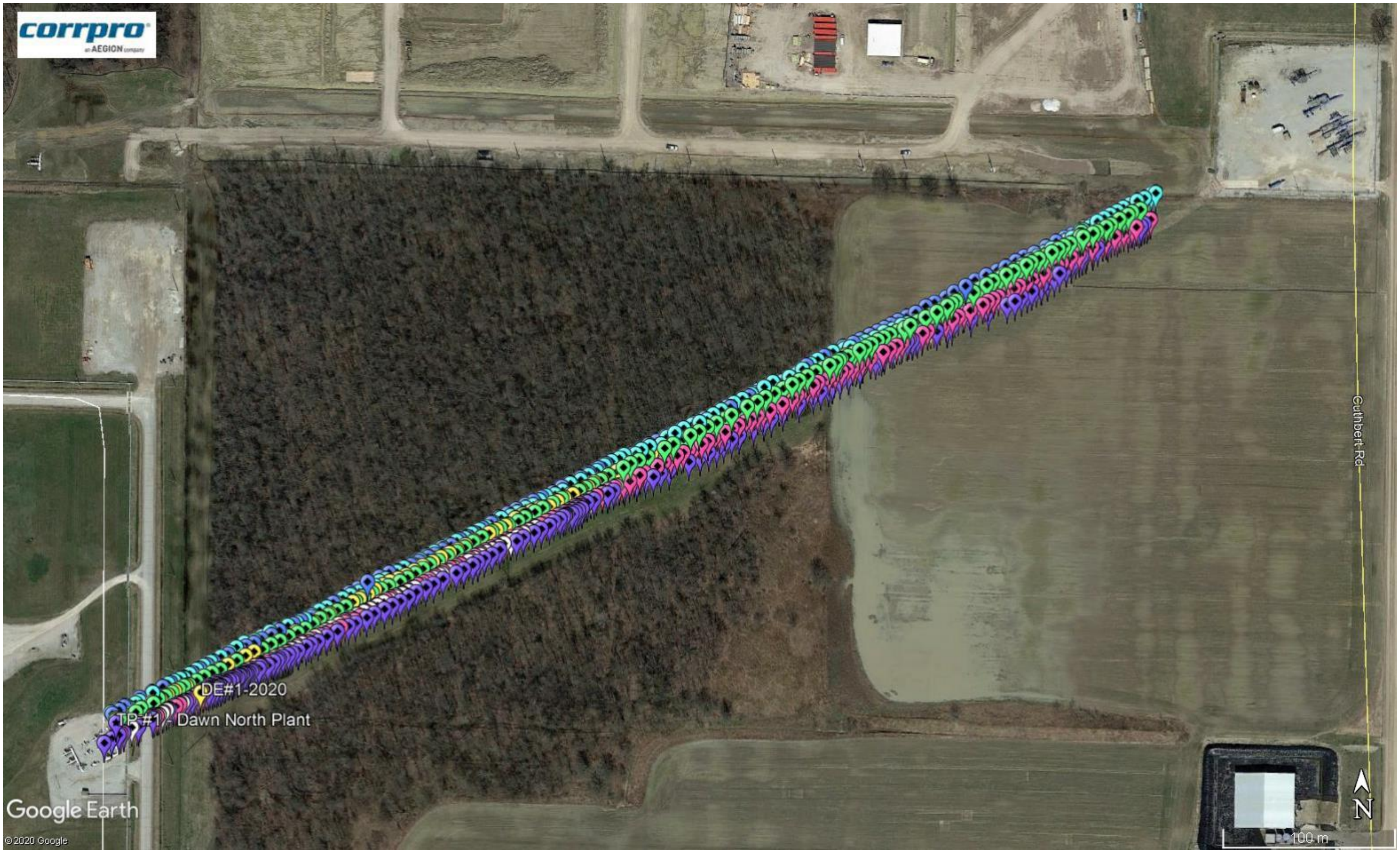


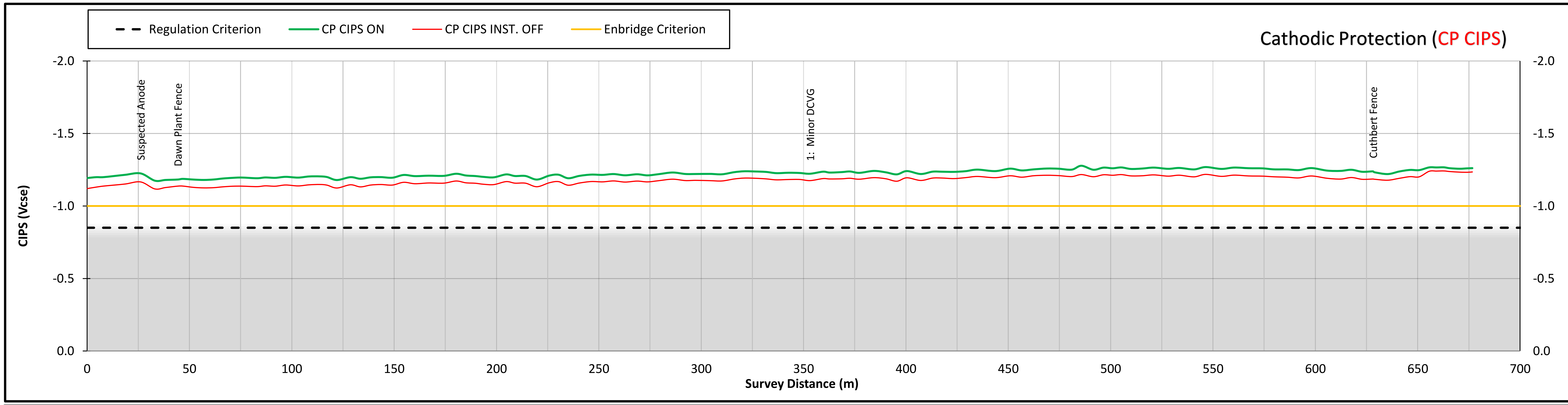
Figure 1: 26", 34", & 42" Trafalgar Lines Dawn Plant to Cuthbert Rd. Survey Overview

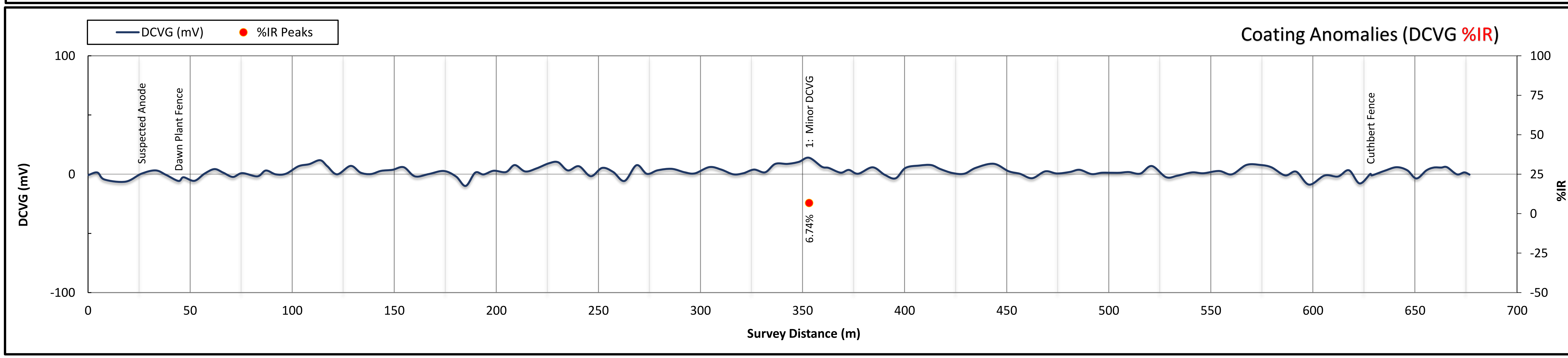
APPENDIX 2 - ABOVE GROUND INSPECTION CHARTS

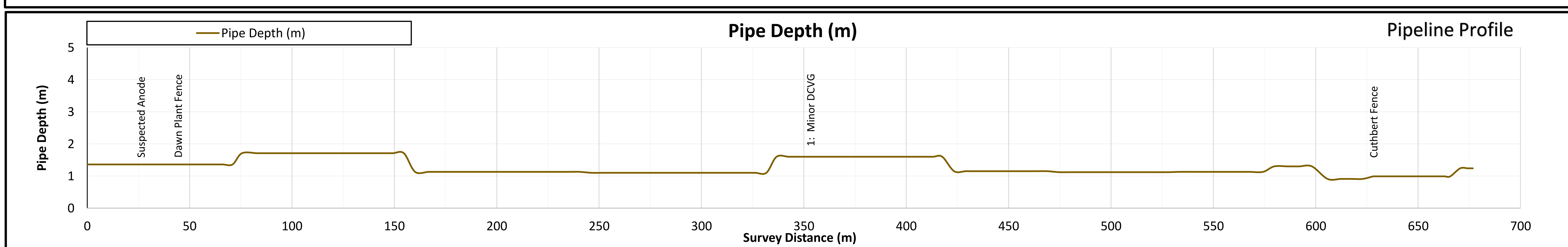
AEGION
Stronger. Safer. Infrastructure.
corrpro

Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

26" Trafalgar Line - Dawn Plant to Cuthber Rd.



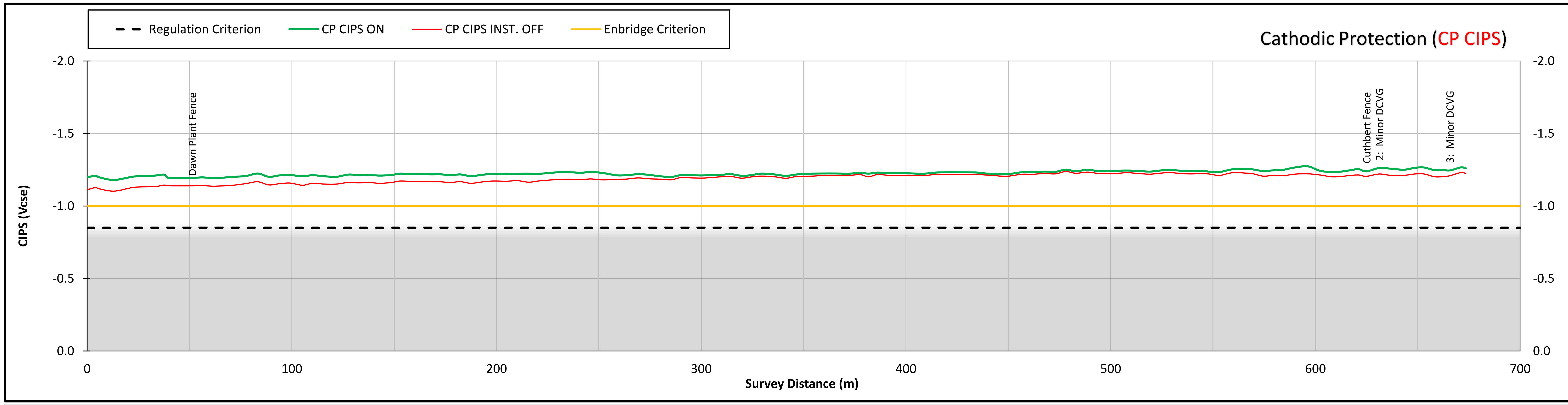


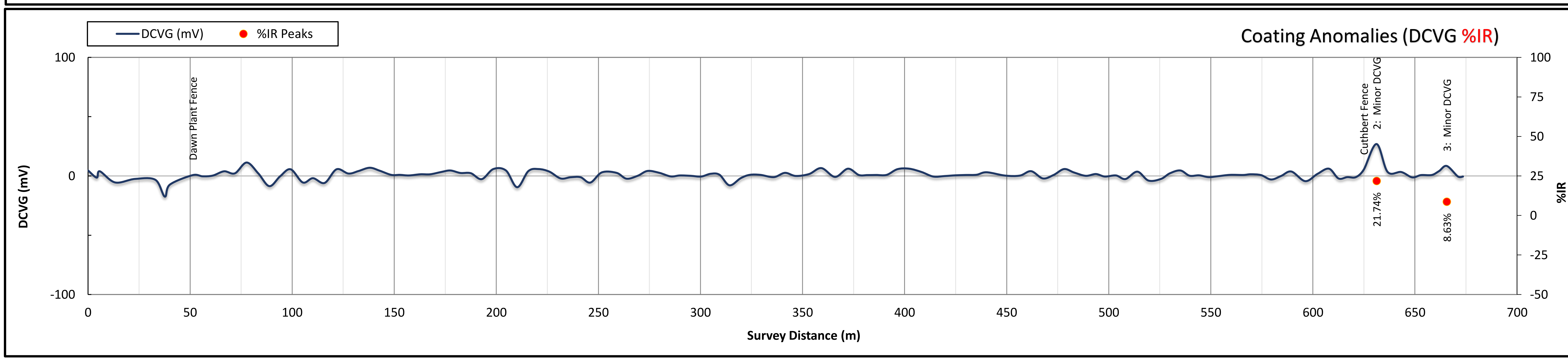


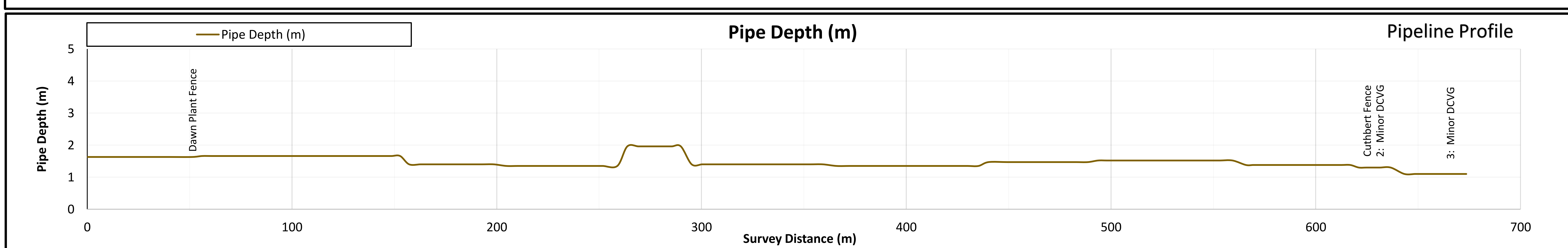
AEGION® Stronger. Safer. Infrastructure.® corrpro

Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

34" Trafalgar Line - Dawn Plant to Cuthber Rd.



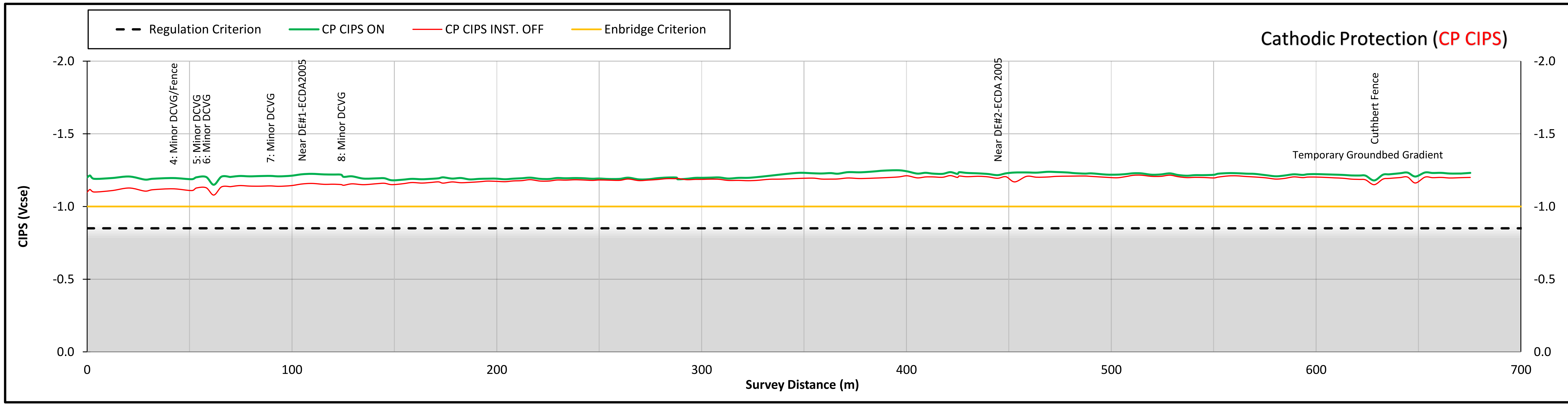


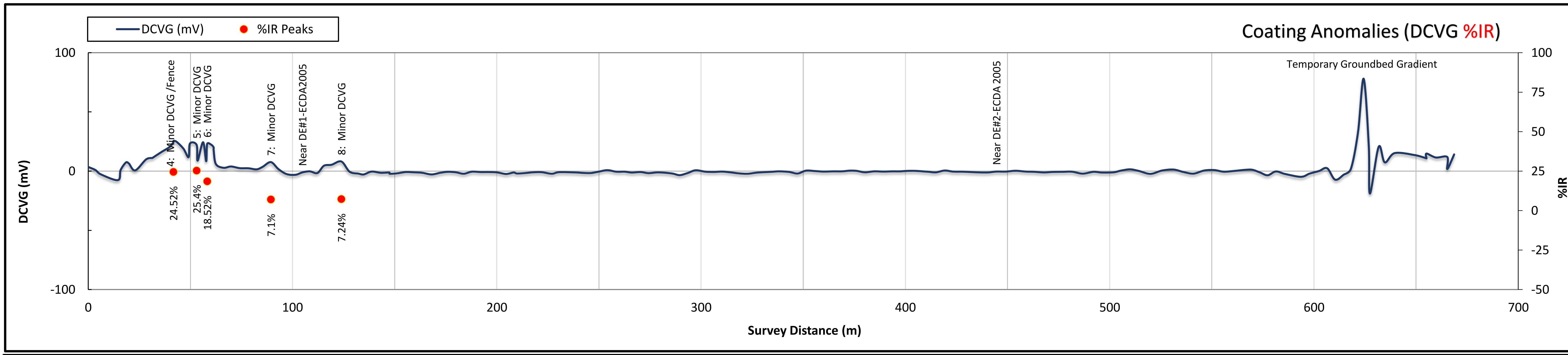


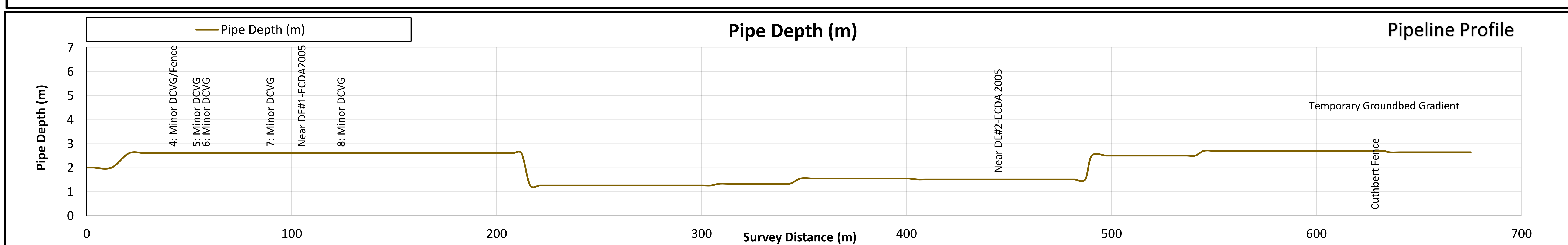
AEGION® Stronger. Safer. Infrastructure.® corrpro

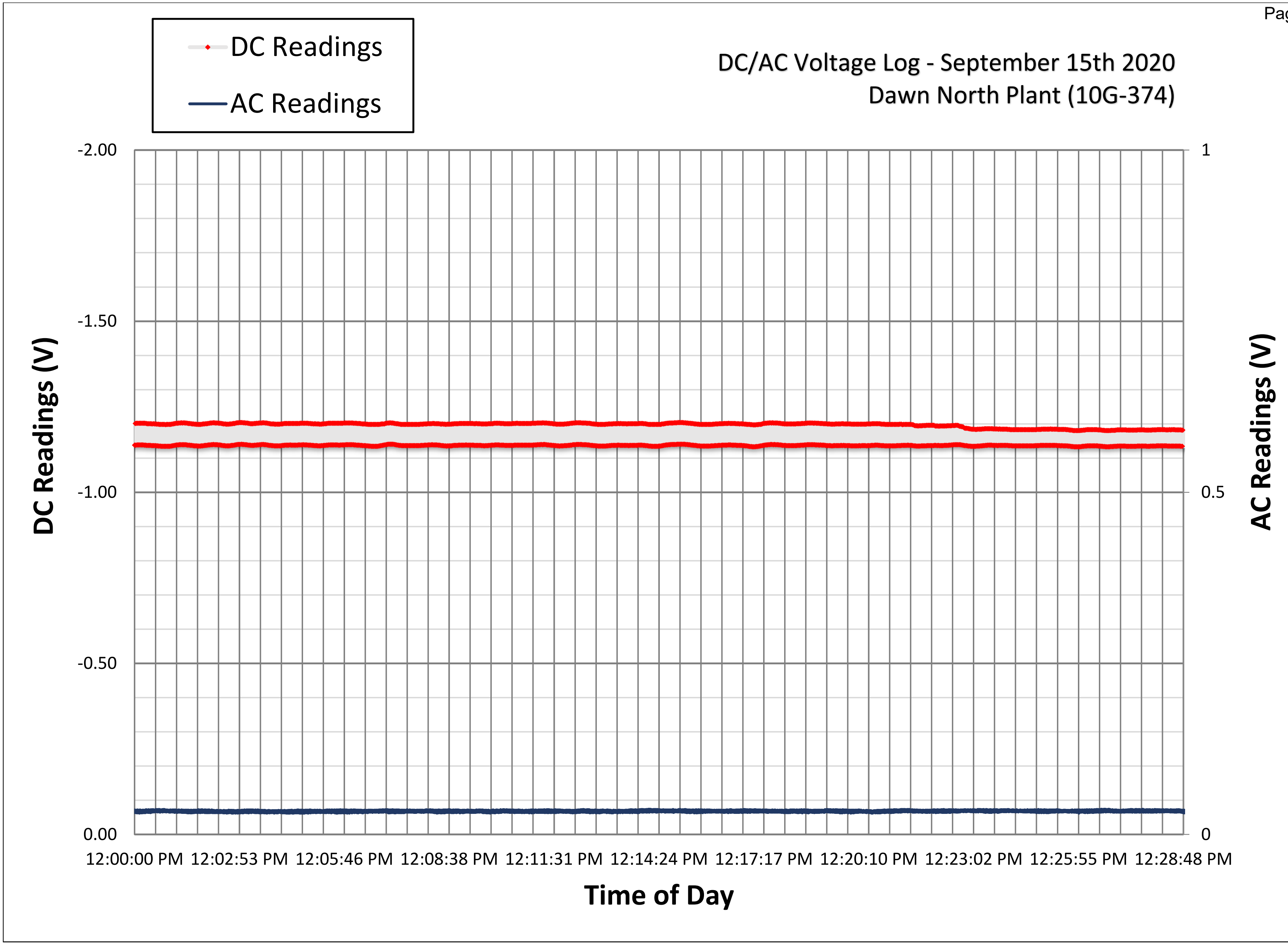
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

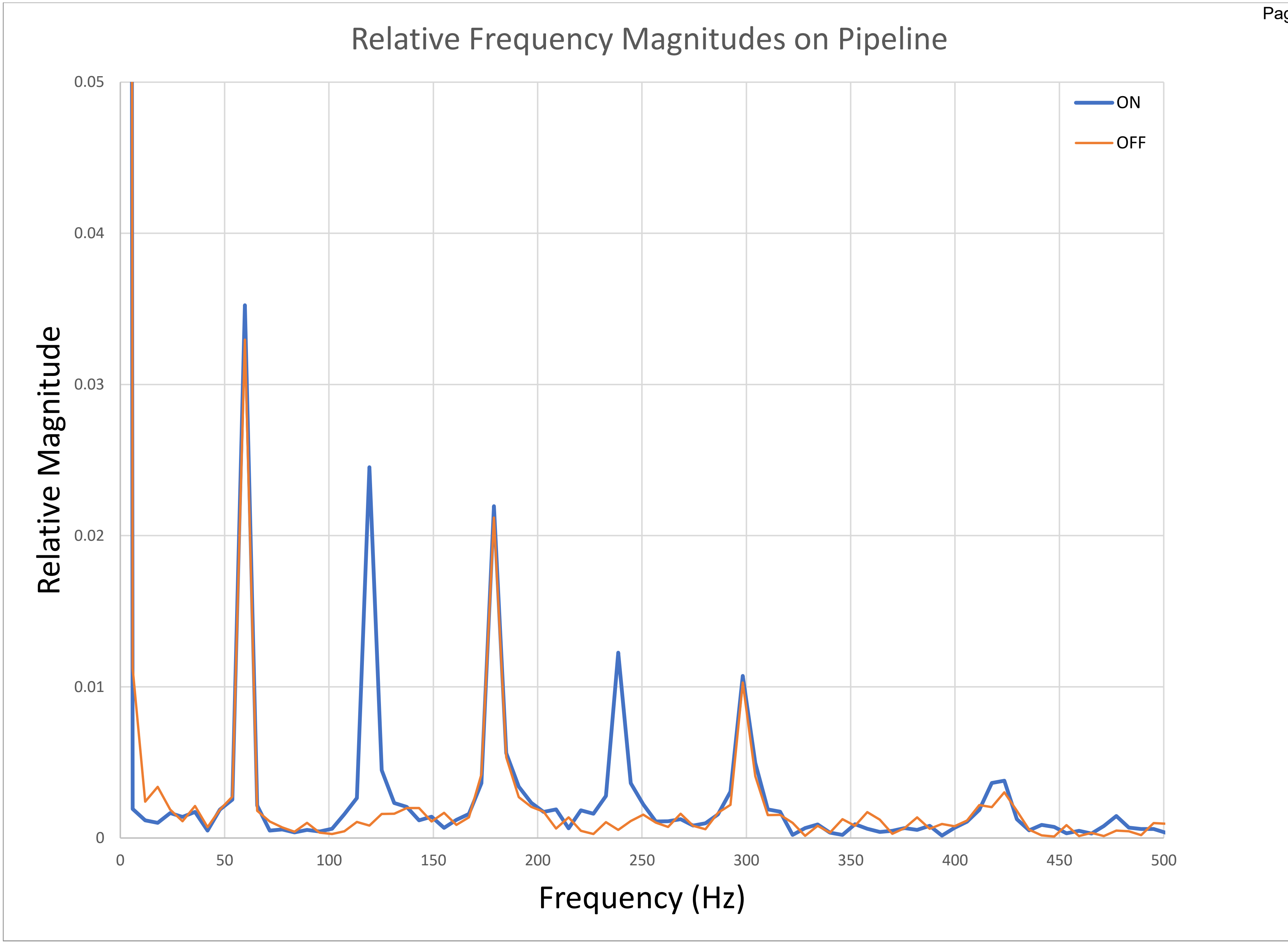
42" Trafalgar Line - Dawn Plant to Cuthber Rd.








DC Readings
AC Readings
DC/AC Voltage Log - September 15th 2020
Dawn North Plant (10G-374)
DC Readings (V)
AC Readings (V)
-2.00
-1.50
-1.00
-0.50
0.00
1
0.5
0
12:00:00 PM
12:02:53 PM
12:05:46 PM
12:08:38 PM
12:11:31 PM
12:14:24 PM
12:17:17 PM
12:20:10 PM
12:23:02 PM
12:25:55 PM
12:28:48 PM
Time of Day


Relative Frequency Magnitudes on Pipeline
Relative Magnitude
0.05
0.04
0.03
0.02
0.01
0
0
50
100
150
200
250
300
350
400
450
500
Frequency (Hz)
ON
OFF

Test Equipment Maintenance and Calibration Procedures

Measuring and test equipment are labelled with calibration due dates and calibrations are completed externally by a third party. Calibration certificates are traceable to the serial numbers on the measuring and test equipment and are available to view upon request. Where there is no serial number noted, a unique number is assigned to the device or tool.

When measuring or test equipment is suspected to be out of calibration or appears to give inaccurate readings, the equipment is checked. If it is confirmed that the equipment is out of tolerance and or nonconforming, a Non conformance report (NCR) is generated and the equipment is labelled as non-conforming and put out of service until it is repaired/recalibrated. Further detail on Corrpro Canada's internal procedures for the control of monitoring and measuring equipment can be provided upon request.

Equipment Utilized for ECDA Surveys

Equipment	Model	Serial No.	Info/Comments
Digital data Logger	CATH-TECH / Hexcorder Pro	2018J2006*	Records CIPS and DCVG data
Sub-meter GPS	AgStar, 0.7m accuracy	574F-713751	Records GPS coordinates for all readings
Pipe Locator	RD8100	PA05/06534	Locates underground pipe and provides DOC readings
Stationary Data Loggers	Mobiltex Cortalk UDL1	03811 03812	Helps detect AC influence from overhead powerlines or telluric activity.
GPS Interrupters	CGI-100	Various	Enables synchronized interruption of rectifiers
Soil Resistivity Meter	AEMC 6471	00005810	Soil Resistivity Testing
Multimeter	Fluke 77-IV	14250706	Reads AC and DC Pipe-to-Soil Potentials
$Cu/CuSO_4$ Reference	M.C.Miller RE-5C	Consumables	Tested daily and replaced monthly

* The calibration of the Hexcorder Pro is traceable to the National Institute of Standards and Technology (NIST) or the National Research Council of Canada (NRC). The certificate of calibration is valid for one year from the date of issue.

Reference Cell Care and Calibration

1) Before use on ECDA survey activities, test both cells daily by placing each of them in a small non-metallic container that has two inches of tap water in it, side by side with a new/calibration cell. The potential measured between the electrodes should be 10 mV or less. Next, the two cells used in the two poles for the ECDA surveys are put together in the same container and the potential measurement between them is noted and recorded as an offset to be taken into consideration in the later stages of data analysis.
2) On the Hexcorder Pro device, with the survey running, the user places the tips of the survey poles with the cells attached together. Touching the tips will reduce the non-error voltage to zero. Pressing the green ZERO button will take a reading and apply an offset to the DCVG channel(s) to correct for ½ cell error.
3) When testing in bright sunlight, be aware that a photoelectric effect may alter the reference cell potential. Under these circumstances, it is good to practice to, cover the clear window on the side of the reference cell with electric tape.
4) The saturated copper sulfate solution in the portable reference cell is checked regularly and changed approximately once per month. The frequency of cleaning and replacing the solution will depend partly upon use. If the solution becomes cloudy or dirty, the cell is cleaned or replaced.
5) To clean the reference cell, remove the copper electrode and clean with a plastic pad or ordinary fine sandpaper to bright metal. Do not use steel wool, a wire brush, emery cloth or any material that may leave a metallic deposit on the copper rod. Place the copper sulfate crystals in the bottom of the cell and fill with distilled water. Crystals should remain on the bottom of the cell to ensure a saturated solution.

APPENDIX 3 - TEST EQUIPMENT AND TOOLS CALIBRATION

PROJECT SCHEDULE

Phase	2020								2021												2022												2023						
	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July
PROJECT DEVELOPMENT																																							
Project Development			■	■	■	■	■	■	■	■																													
Option selection					■																																		
ENVIRONMENTAL																																							
Site Survey and SAR studies											■	■	■	■	■	■																							
Initial Soil sampling and Report											■	■	■	■	■																								
Hydrogeological Assessment												■	■	■	■	■	■																						
Obtain Permits																	■	■	■	■	■	■	■																
PROCUREMENT																																							
Construction Contract Procurement																■	■	■	■	■	■																		
Procurement - Mainline pipe													■	■	■	■	■	■	■	■	■	■																	
ENGINEERING & CONSTRUCTION																																							
Pre-FEED and FEED study							■	■	■	■	■	■																											
Engineering Design													■	■	■	■	■	■																					
Tree Clearing																						■																	
Mainline Construction																										■	■	■											
NPS 42 Abandonment																										■													
Hydrotest																											■		In-Service										
Final Tie-Ins and Commissioning																												■	■										
Year after Clean-up activities																																						■	

ALTERNATIVES AND PROJECT DESCRIPTION

Summary of Alternatives

1. This evidence sets out the process and criteria used to select the alternative that best mitigates the pipeline's integrity concern while continuing to serve existing system demands.

2. When existing facilities have known integrity concerns, alternatives are generated to extend the useful life of the asset or replace the asset. The alternatives considered for this Project are listed as follows:
   - Monitor the condition of the NPS 42 Dawn to Cuthbert Pipeline with an ILI tool capable of detecting SCC (EMAT).
   - Like-for-like replacement of the existing NPS 42 pipeline, including with modern coating that alleviates the threat of future SCC.
   - Replacement of the existing NPS 42 with different diameter/MOP pipeline, including with modern coating that alleviates the threat of future SCC.

3. All alternatives are given preliminary review for feasibility, and practicable ones are organized into a key alternatives list.

4. Each alternative on the key alternatives list is evaluated in detail to make a final recommendation.

5. Criteria for selecting the best alternative include, but are not limited to:
   - Economic feasibility
   - Construction feasibility
   - Capacity created
   - Reliability of supply
   - System integrity benefits

Project Alternatives

6. The following key alternatives were identified and assessed for the NPS 42 Dawn to Cuthbert Replacement Project:

a) Monitor the condition of the NPS 42 Dawn to Cuthbert Pipeline with an ILI tool capable of detecting SCC ("Option A")

Enbridge Gas reviewed the option of running an EMAT ILI tool on the NPS 42 Dawn to Cuthbert pipeline to detect SCC and defer replacement of the pipeline until 2031. In the gas transmission pipeline industry, EMAT is among the most expensive ILI tools to run, and is specifically used on pipelines that have SCC concerns. This option includes the costs associated with installing tool launching and receiving facilties, as well as eventual replacement. The cost of running an EMAT inspection is typically at least four times higher than the cost of a conventional MFL and caliper tool campaign. This option considered the long-term capital and O&M costs resulting from deferring the replacement until 2031 by modifying the pipeline to accept ILI tools, performing periodic EMAT and MFL inspections and subsequent integrity digs.

b) Like-for-like replacement of the Existing NPS 42 Dawn to Cuthbert pipeline ("Option B")

Enbridge Gas reviewed the option of replacing the existing pipeline with a new NPS 42 pipeline. The pipeline would operate at the same MOP as the existing pipeline and would be installed with a modern coating that is not susceptible to SCC. As a result, the pipeline would not be required to have an EMAT inspection to monitor for SCC. Although EMAT would not be required, tool launching and receiving facilities are proposed to be installed to monitor the condition of the pipeline with conventional ILI tools for the life of the asset. This would take advantage of construction synergies during the replacement because the pipeline will still need to be inspected as described in the Asset Management Plan.[1] This option represents

[1] Enbridge Gas Asset Management Plan filed in EB-2021-0181, Exhibit A, Tab 2, Schedule 1.

a greater overall risk reduction due to the complete removal of the SCC threat for the life of the asset, while still allowing for periodic condition monitoring of the pipeline against other active threats with conventional ILI tools such as MFL and caliper.

c) Replacement of the Existing NPS 42 Dawn to Cuthbert pipeline with different diameter/MOP ("Option C")

Since the NPS 42 Dawn to Cuthbert pipeline directly feeds into the NPS 42 Dawn to Kirkwall pipeline, a different diameter was not considered to be a viable alternative. A smaller diameter pipeline would create a pressure bottleneck which would result in the inability to provide the appropriate flow and pressure required to the Dawn Parkway System.

Installing a larger diameter pipeline would be beneficial from a future capacity perspective, however, this capacity gain would necessitate the similar replacement of the existing NPS 42 pipeline from Dawn all the way to Kirkwall. It was decided there was insufficient justification at this time to support the additional cost to upsize the pipeline.

Alternatives Assessment

7. Enbridge Gas performed quantitative and qualitative assessments on Option A and Option B, identified above. Option C was not considered further due to the reasons discussed above.

8. The quantitative assessment assessed the economic feasibility of both options using a Net Present Value ("NPV") analysis. Option A was determined to be the higher cost alternative compared to Option B over a 40-year horizon. Furthermore, Enbridge Gas noted that the assessed NPV of Option A could vary significantly based on the results of EMAT ILI inspections over the 40 year period, which may result in the need to repair or replace segments of pipeline earlier than anticipated in the analysis. This analysis is presented in Attachment 1 to this Exhibit.

9. In addition to the quantitative analysis, several qualitative factors were considered:
   - Impact to the public and reputational damage to Enbridge Gas in the instance of failure given that the pipeline supplies the Dawn Parkway System. A failure will reduce public confidence in the safety and reliability of Enbridge Gas's network.
   - Environmental impacts associated with loss of containment caused by SCC.
   - The potential for SCC to quickly worsen to a threshold where guidance from CEPA recommends a restriction to operating pressure on short notice, creating an increased security of supply risk for the Dawn Parkway System.

10. Based on the results of these assessments, Enbridge Gas determined that the best alternative to manage the long-term integrity of the NPS 42 Dawn to Cuthbert pipeline is a like-for-like replacement of the existing 650 m NPS 42 pipeline.

11. Replacing the existing NPS 42 with a new NPS 42 completely mitigates the risk of SCC as the new pipeline will be installed with a modern external coating that is not susceptible to SCC. Furthermore, including launcher and receiver facilities allows for the ongoing monitoring of other pipeline threats using conventional ILI tools.

Integrated Resource Planning

12. The Decision and Order for Enbridge Gas's Integrated Resource Planning Framework Proposal (EB-2020-0091) was issued on July 22, 2021 by the Ontario Energy Board ("OEB"). The Decision was accompanied by an Integrated Resource Planning Framework for Enbridge Gas ("IRP Framework")[2] which provides guidance about the nature, timing and content of IRP considerations for future identified needs. The IRP Framework provides Binary Screening Criteria in order to focus on projects where there is reasonable expectation that an IRPA could efficiently and economically meet a system need. Enbridge Gas has applied the Binary Screening Criteria and determined that the need underpinning the Project does not warrant further IRP consideration, as the need occurs within the 3 year time horizon:

---

[2] EB-2020-0091, Decision and Order, July 22, 2021, Appendix A

> ii. Timing – If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need..[3]

13. As discussed in Exhibit B, Tab 1, Schedule 1, the Project is driven by a system integrity determination that replacement of the pipeline mitigates the risks identified. The Project will also allow Enbridge Gas to perform necessary compliance and safety operations on this section of pipeline.

14. As the Project is driven by integrity concerns that must be addressed within three years, no demand side solution can resolve the integrity concerns.

15. Consequently, project alternatives considered consist of several pipeline scope and timing options which are summarized below.

<u>Proposed Facilities</u>

16. This Project consists of replacing 650 m of NPS 42 ST pipeline in addition to installing provisions to launch and receive ILI tools. The replacement pipeline will run from the Cuthbert Measurement Station southwest to Trafalgar Valve Nest where it connects to the existing NPS 42 pipeline west of this location. Exhibit B, Tab 1, Schedule 1, Attachment 1 provides a map identifying each major element of the Project.

17. The proposed design of the Project, including: pipeline diameter and length, as well as the maximum operating pressure of the Project match the currently forecasted demand of the Existing Line. In addition to the pipeline replacement, modifications to allow the passage of ILI tools for future integrity management activities will be made.

18. For locations where the pipeline is being replaced, the pipeline will be primarily installed using a lift and lay method, whereby the Existing Line will be removed and

---

[3] Ibid., p.10

the same trench utilized for the install of the proposed pipeline, with modifications made to the trench to ensure applicable installation and backfilling standards are met.

19. The entirety of the Project work will take place on existing Enbridge Gas-owned lands.

20. Sections of the 650 m of NPS 42 pipeline will be removed and replaced with the new NPS 42 pipeline between the Dawn Compressor Station and the Cuthbert Measurement Station. As the method of install is lift and lay, the existing NPS 42 Dawn to Cuthbert pipeline will need to be isolated and removed for the utilization of the trench. The proposed new pipeline will be hydrostatically tested before energization.

21. The total estimated cost of the Project is approximately $24.2 million. This total includes indirect overheads. Without indirect overheads and IDC included, the total estimated cost is $19.6 million.

Project Timing

22. Enbridge Gas is planning to construct the Project between June and September 2022, with an in-service date of September 30, 2022. Site restoration would occur between May and July of 2023. See Exhibit B, Schedule 1, Attachment 10 for a detailed Project schedule.

NET PRESENT VALUE ASSESSMENT OF ALTERNATIVES

1. As discussed in Exhibit C, Tab 1, Schedule 1, Enbridge Gas conducted an analysis of the costs to inspect and maintain the existing NPS 42 Dawn to Cuthbert pipeline using EMAT ILI (Option A) compared to the cost to replace the pipeline (Option B). Due to the known SCC issue discussed in Exhibit B, Tab 1, Schedule 1, Option A includes an assumption of replacement in 2031.

2. The analysis set out in Table 1 below assumes a 40-year time horizon, consistent with the approximate depreciable life of the Project. The costs related to Option A and B scenarios were then discounted using the methods prescribed by the OEB's E.B.O. 188 to arrive at a net present value for each.

3. Included in the analysis of Option A were costs related to running an EMAT ILI campaign every 5 years at a cost of $800,000 per inspection until an assumed pipeline replacement in 2031. Following replacement, a conventional MFL and caliper ILI would be required every 10 years over the next 30 years at a cost of $200,000 per inspection. Option A also assumed 10 integrity digs would have to be conducted over the next 40 years, including 3 after each EMAT inspection and 1 after each conventional MFL and caliper ILI.

4. For the analysis of Option B, in addition to the cost of the immediate pipeline replacement, Enbridge Gas assumed a conventional MFL and caliper ILI would be conducted every 10 years over the next 40 years at a cost of $200,000 per inspection. Option B assumes 1 integrity dig occurring after each conventional MFL and caliper ILI.

5. Because the costs for integrity digs on the pipeline are estimated to range between $250,000 and $300,000, an average cost of $275,000 per dig was assumed.

6. Table 1 provides a summary of the results of the cost comparison analysis. Over a 40-year time horizon the total cost of replacement is essentially equivalent to the cost of inspection and maintenance with a future replacement assumed in 2031.

Table 1: NPV Analysis Results

$Millions	Option A (Inspect/Maintain, Replace in 2031)	Option B (Replace)
Net Present Value (Life Cycle)	**(20.21)**	**(20.13)**

PROJECT COSTS AND ECONOMICS

Project Costs

1. The total estimated cost of the Project is $24.2 million as shown in the Table 1 below. This cost includes: (i) materials; (ii) construction and labour; (iii) environmental protection measures; (iv) contingencies; (v) interest during construction ("IDC"); and (vi) indirect overheads.

Table 1: Estimated Project Costs

Dawn-Cuthbert Project Costs in $	
Internal Labour	180,000
Contract Labour	10,350,000
Third Party Services	3,300,000
Materials	3,600,000
Lands	10,000
Contingency	2,180,000
Project Costs	**19,620,000**
IDC	150,000
Indirect Overheads	4,390,000
Total Project Costs	**24,160,000**

2. The cost estimates set out in Table 1 include an 11.4% contingency applied to all direct capital costs.

Project Economics

3. A Discounted Cash Flow report has not been completed as the Project is underpinned by integrity requirements.

Business Case:

Byron Transmission Station

EXHIBIT LIST

A – ADMINISTRATION

Exhibit	Tab	Schedule	Contents of Schedule
A	1	1	Exhibit List

B – PROJECT NEED

Exhibit	Tab	Schedule	Contents of Schedule
B	1	1	Project Need
			Attachment 1a – 2019 Noise Impact Study
			Attachment 1b - 2019 Noise Impact Study
			Attachment 2 - Project Schedule

C – ALTERNATIVES & PROJECT DESCRIPTION

Exhibit	Tab	Schedule	Contents of Schedule
C	1	1	Alternatives & Project Description

D – COST & ECONOMICS

Exhibit	Tab	Schedule	Contents of Schedule
D	1	1	Project Costs & Economics

PROJECT NEED

Introduction

1. Enbridge Gas Inc. ("Enbridge Gas" or the "Company") has identified the need for a full rebuild of the existing Byron Transmission Station ("Project") as a result of heater integrity, noise complaints and compliance, maintenance/operational standards and valve integrity concerns, as well as to serve increasing natural gas demand in the London area. Construction of the new Byron Transmission Station began in May, 2021. The planned in-service date ("ISD") for the Project is August 31, 2022.

2. As early as 2018, the Company (Union Gas Limited at the time) identified a number of integrity, safety, reliability, maintenance and operational concerns that supported a rebuild of the Station. This project was reassessed in 2020/2021 given the escalated concerns surrounding integrity, noise, and maintenance/operational standards, as discussed in more detail below, and ultimately designed in order to principally address those concerns while also ensuring that the longer term demands of the London market (beyond 2022) could be met by the Project.

3. The existing Byron Transmission Station (the "Station") is located on Enbridge Gas-owned property within a fenced compound in the community of Byron located at 2023 Wickerson Road, London, Ontario. Figures 1 and 2 below illustrate the Project area.

4. The Station accepts natural gas from the Dawn Parkway System and reduces or regulates pressure for distribution to the 3,450 kPa, 1,380 kPa, and 420 kPa downstream systems. The station supplies natural gas to a majority of the London, St. Thomas and Port Stanley systems.

5. In addition to providing pressure regulation/reduction, the Station also uses a heating system consisting of an indirect fired heater and a glycol heat exchanger to pre-heat natural gas flowing from the station into the distribution systems to avoid frost heave, which can cause considerable damage to natural gas distribution assets, roads and private property. Specifically, the effect of frost heave on pipelines can be significant, in extreme instances causing excessive stress or strain to produce a failure in station components by ground movement.

Figure 1: Location of the Project

Figure 2: Project Area

Purpose and Need

6. Enbridge Gas's Project is required due to address:
   a) integrity concerns discovered as part of the Company's indirect heater assessment;
   b) noise concerns raised by complainants and confirmed by the Company's Noise Impact Study;
   c) maintenance and operations concerns regarding equipment spacing and integrity concerns associated with Station inlet valves; and
   d) inability of the existing Station to support the long term demands of the London market beyond 2022.

a) - Heater Integrity Concerns

7. The heating system at the existing Station was installed in 1968 (BS&B) and a heater addition was installed in 1979 (NATCO). The heating system has degraded over time, and is now only capable of operating at approximately 50% of its original rated output capability. There has also been an increasing risk of glycol spills from

these heaters and the station does not have any secondary containment in place to prevent potential impact to the surrounding soils resulting from a large spill.

8. In late 2018, Enbridge Gas conducted a system-wide indirect heater assessment (including size, condition and operation of heater systems) and identified both of the heaters at the Station as Risk Rank 2 (L3 C4)[1]. The assessment recommended that the heaters be replaced in 2021.

9. The condition of the heating system at the Station has raised environmental, safety, and reliability concerns. In the event of a heater failure at the Station, Enbridge Gas estimates that there is potential that more than 5,000 customers fed from the
420 kPa feed on a cold winter day (high inlet pressure and high volumes of flow) in the London area alone could be impacted by resulting freeze offs that may occur along the respective downstream distribution system regulators.

b) - Noise Concerns

10. During Q4 2018, noise complaints were filed with the government of Ontario against the Byron Transmission Station by the owners of neighboring properties.

11. As a result, in early 2019, Enbridge Gas completed a Noise Impact Study on the Station and based on the measurements conducted concluded that the noise levels of the existing Station exceeded the applicable Ontario Ministry of the Environment, Conservation and Parks ("MECP") limit by up to 20 dBA at the nearest receptors. The Noise Impact Study can be found in Attachment 1A and Attachment 1B to this Exhibit. This study also used predictive analysis to assess the potential impact of sound emissions from the upgraded station with respect to MECP guideline NPC-300, and with consideration for the City of London noise by-

[1] Consistent with the Project Prioritization and Selection and Risk Matrix discussed in the Legacy Union Gas 2019-2028 Asset Management Plan filed in EB-2018-0305, Exhibit C1, Tab 3, Schedule 1, pp.46-53.

law. Ultimately, the study found that most of the sound was attributed to the boilers, above-grade piping and metering and regulation equipment located at the existing Station, all of which would be addressed by the Project.

c) - Maintenance and Operation Concerns

12. The existing Station configuration provides inadequate spacing between existing equipment (less than 1 metre), leading to ergonomic and operational concerns for technicians during inspections, routine maintenance work or planned construction activities. There is also concern for worker safety with regards to egress if there was ever an incident while working on the regulator runs.

13. Further, Enbridge Gas notes that the Station inlet valve is seized in a position that is approximately 90% open due to the deteriorated state of the valve. As such, the Station inlet valve is no longer considered reliable and requires replacement.

d) - Growth

14. Due to projected growth in downstream general service markets fed by the Station, in 2018 Enbridge Gas projected that the Station could reach capacity by the end of 2022. Specifically, Enbridge Gas concluded that the regulation system and the heating system at the existing Station would be incapable of meeting system demand projected by winter 2022/23.

15. Rebuilding the entirety of the station will have added benefit of providing increased certainty for customers' planning purposes. The new station will have adequate capacity to support a minimum of 225,000 m^3/hr flow in the future (as compared to its current capacity of 170,000 m^3/hr which is limited by heating systems).

Project Timing

16. Project development, including land negotiations and initial station design, began in 2019. However, due to difficulties in land negotiations, the required land was not

secured until November 2020, delaying the finalization of engineering design and Project permit applications.

17. In April 2021, the Project ISD was updated to August 31, 2022 due to several factors including: delays in securing site plan approvals and building permits, additional construction scope arising from the site plan consultation process with the City of London, and industry wide material procurement delays largely related to the unprecedented and ongoing COVID-19 pandemic.

18. The new station is being constructed around the existing Station in order to ensure that the Company can maintain reliable and safe delivery of natural gas supply volumes downstream of the Station through winter 2021/2022. Following the completion of Project construction in Q3 2022 the existing Station will be decommissioned/abandoned and removed from site.

19. The Project schedule is provided as Attachment 2 to this Exhibit.

HGC ENGINEERING

Howe Gastmeier Chapnik Limited
2000 Argentia Road, Plaza One, Suite 203
Mississauga, Ontario, Canada L5N 1P7
t: 905.826.4044

November 29, 2018

Ms. Luna Munro
Union Gas Limited
50 Keil Drive North
Chatham, Ontario
N7M 5M1

Re: Acoustical Measurements of the Byron Transmission Station
2023 Wickerson Road, London, Ontario

Dear Ms. Munro,

As requested, HGC Engineering conducted acoustical measurements in the vicinity of the Byron Transmission Station ("TS") in London, Ontario, to determine whether the sound levels of the TS comply with the applicable sound level limits of the Ontario Ministry of the Environment, Conservation and Parks ("MECP"). The results of the measurements indicate that the sound levels of the Byron TS are within the applicable MECP limit at the majority of nearby homes, but may exceed the limit by up to 12 dBA at the nearest homes, immediately adjacent to the station.

1 Context

The Byron TS is located at 2023 Wickerson Road in London, Ontario, southwest of the intersections of Wickerson Road and Byron Baseline Road, as shown in Figure 1. The primary noise producing equipment at the site include two heaters, and above-grade natural gas piping and metering/regulation equipment. The station operates 24 hours per day.

The most potentially impacted, existing noise-sensitive points of reception to the TS were identified as single family dwellings located to the south, southeast and northeast, at distances of between 70 and 420 metres from the TS. These homes are visible in the satellite image overlay in Figure 1. Also visible in the image are new homes currently under construction on the east side of Wickerson Road, east of the TS. During a site visit by HGC Engineering personnel on November 22, 2018, background sound in the area was observed to be dominated by road traffic on Byron Baseline Road, and other distant roadways. In that regard, the area is best categorized as a Class 1 acoustical environment, in accordance with MECP guidelines.

2 Criteria

MECP Publication NPC-205[1] is the applicable guideline for establishing sound level limits for stationary sources of sound associated with the Union Gas system, such as the subject TS. NPC-205 stipulates that the sound level limit for a stationary source which operates during both daytime and nighttime hours in a

[1] Ontario Ministry of the Environment, Conservation and Parks Publication NPC-205, "Sound Level Limits for Stationary Sources in Class 1 & 2 Areas (Urban)," October, 1995.

Class 1 (urban) environment is the greater of the minimum one-hour energy-equivalent (L_{EQ}) background sound level, or the exclusionary minimum limit of 45 dBA. The guideline also stipulates that the noise assessment shall consider a *predictable worst-case hour*, which is defined as an hour when typically busy operation of the stationary sources funder consideration could coincide with an hour of low background sound.

Based on observations during the November 22, 2018 site visit, it is expected that background sound levels may fall below the exclusionary minimum outlined above during the quietest hours of the night. Therefore, the sound level limit applicable at the homes neighbouring the Byron TS is 45 dBA.

3 MEASUREMENT METHODS, INSTRUMENTATION & RESULTS

During the site visit, sound level measurements were conducted at four locations, labelled as M1 through M4 in Figure 1, generally in conformance with MECP procedural guideline NPC-1032. The measurements were conducted using a Norsonic Precision Sound Analyser, Model Nor140, and a Larson Davis Larson Davis Integrating Sound Level Meter, model 831. All instrumentation was within its laboratory calibration period. Field checks of correct calibration were made before and after the measurements, during which the meteorological conditions were suitable for outdoor acoustical measurements.

Two quantities of note were recorded during the measurements: the L_{EQ} and the L_{90} sound levels. The L_{EQ} sound level is the *energy-equivalent sound level*, and represents the integrated sound exposure level of both steady and time-varying sounds over the duration of the measurement. The L_{90} represents the sound level which is exceeded 90 percent of the time over the duration of the measurement, and is therefore useful in identifying the contribution of steady sources such as sound emissions from the Byron TS (where audible) to the overall sound level, and rejecting transient sounds such as road traffic and sporadic natural sounds.

A summary of the measurement results is provided below:

Table 1: Summary of Sound Level Measurements

Measurement Location	Sound Level, dBA		Observations
	L_{EQ}	L_{90}	
M1	60	57	Byron TS audible, 50% heaters, 50% piping/regulation
M2	46	40	Byron TS faintly audible, mostly heaters
M3	55	37	Byron TS inaudible
M4	43	36	Byron TS inaudible

4 DISCUSSION & CONCLUSION

From the information in Table 1, it is evident that the Byron TS was not audible or measurable over background sound at locations M3 and M4. At location M2, the TS was only faintly audible, and the measured L_{90} sound level (which is most representative of sound from the TS alone) was well within the applicable criterion of 45 dBA. At location M1, immediately south of the station, the measured sound

[2] Ontario Ministry of the Environment, Conservation and Parks Publication NPC-103, "Procedures," August, 1978.

level exceeded the applicable criterion by 12 dBA, which was qualitatively attributed to sound from both the heaters and the above-grade natural gas piping and/or metering/regulation equipment.

Trusting this satisfies your current requirements, if you have any questions or require anything additional, please do not hesitate to contact the undersigned.

Best regards,

Howe Gastmeier Chapnik Limited

Corey D. Kinart, MBA, PEng

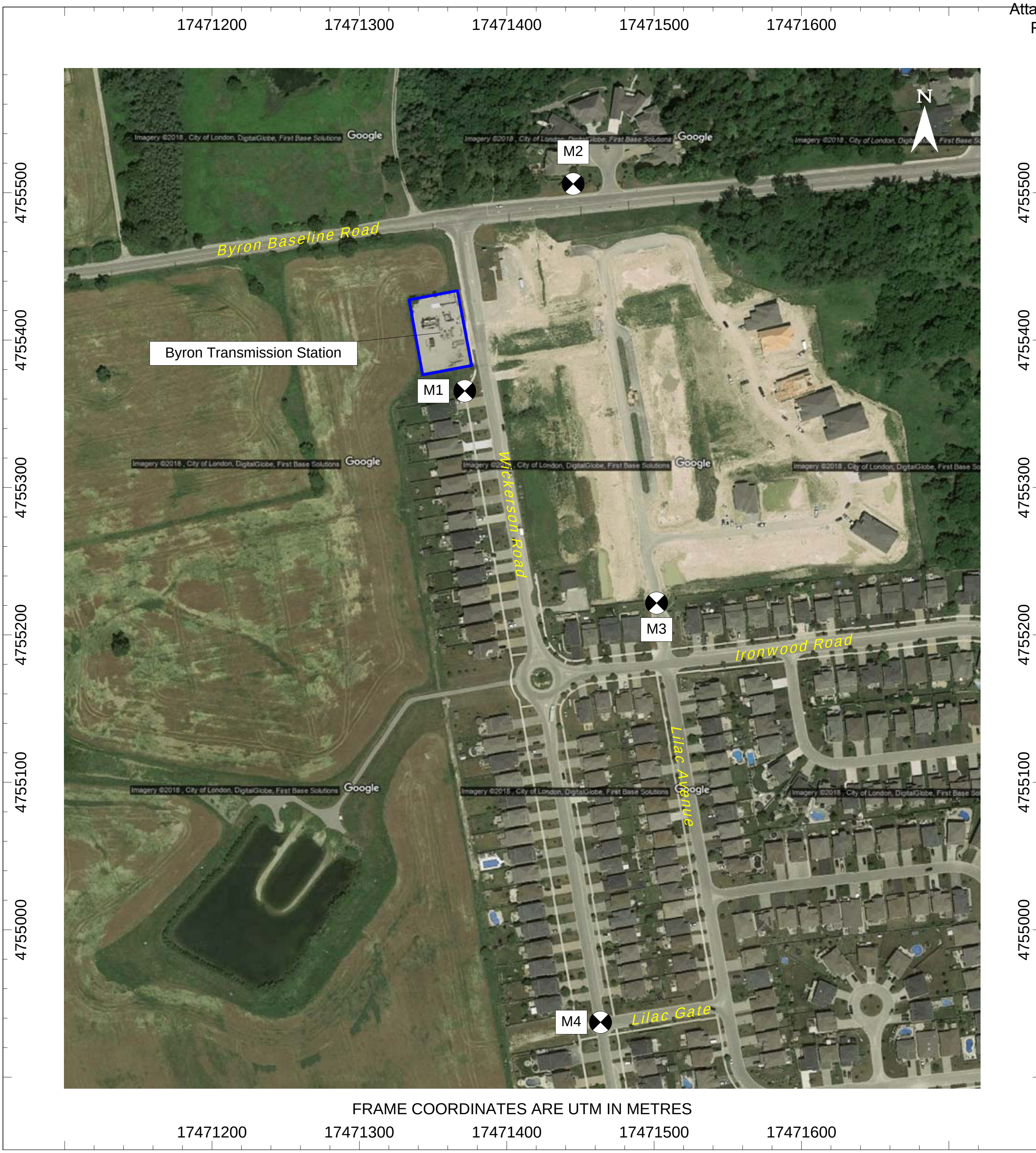


Figure 1: Satellite Image Showing Union Gas Byron Transmission Station and Locations of Sound Level Measurements on November 22, 2018

HGC ENGINEERING

Howe Gastmeier Chapnik Limited
2000 Argentia Road, Plaza One, Suite 203
Mississauga, Ontario, Canada L5N 1P7
t: 905.826.4044

NOISE IMPACT STUDY

Enbridge Gas Inc. Byron Transmission Station Upgrade

2023 Wickerson Road, London, Ontario

Prepared for

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario
M2J 1P8

LICENSED PROFESSIONAL ENGINEER
04-Mar-21
C.D. KINART
100079328
PROVINCE OF ONTARIO

Prepared by

Corey D. Kinart, MBA, PEng

March 4, 2021

HGC Project No. 02000429

ACOUSTICS NOISE VIBRATION

Table of Contents

1 INTRODUCTION & SUMMARY

HGC Engineering was retained by Enbridge Gas Inc. ("Enbridge") to undertake a noise impact study of proposed upgrades to the Byron Transmission Station ("TS") located at 2023 Wickerson Road in London, Ontario, in support of an application to the City of London for site plan approval. A scaled location map of the surrounding area is included as Figure 1. In both the existing state and upgraded design, the site hosts natural gas regulation equipment, boilers/heat exchangers and above-grade piping; the upgraded station will also include an emergency generator. The study uses predictive analysis to assess the potential impact of sound emissions from the upgraded TS with respect to Ontario Ministry of the Environment, Conservation and Parks ("MECP") guideline NPC-300, and with consideration to the City of London noise by-law.

Sound emissions from key items of equipment were based on predictions using acoustical engineering formulae, manufacturer's data and measurements conducted at the site under existing conditions. The source sound levels were used to develop an acoustical model of the site and surrounding area in order to predict the sound levels of the upgraded TS at the nearest sound sensitive points of reception, for evaluation with respect to the MECP limits.

The analysis indicates that the sound levels of the upgraded boiler system and regulation equipment will be reduced considerably, relative to the existing case, and within MECP limits (given they will be enclosed within buildings, whereas they are currently located outdoors). Similarly, the sound levels of the emergency generator are also predicted to be within the applicable MECP limit.

As detailed in Section 4, developing reliable predictions of sound emissions from above-grade gas piping is a considerable challenge. Although a conservative analysis undertaken herein suggests that noise control may be warranted for above-grade piping, developing specific noise control recommendations at this time may be premature, given the uncertainties involved (i.e. the degree of noise control could be over or under specified). It is recommended that the upgrade project include detailed acoustical measurements at the earliest opportunity following commissioning of the TS to determine the extent of noise control required (if any) for above grade piping, which will inform the design of tailored noise control measures.

2 CONTEXT

The site is located at 2023 Wickerson Road in London, Ontario, southwest of the intersections of Wickerson Road and Byron Baseline Road. The current and future operations are, in principle, the same: the station operates 24 hours per day, drawing natural gas from underground high pressure main lines through pressure reduction (regulation) equipment for distribution to the surrounding area. Upstream of the pressure reduction, the natural gas is pre-heated to avoid the formation of hydrate, with the heating system consisting of boilers and a glycol heat exchanger system. The upgraded station will also include a natural gas-fired emergency power generator, which will be tested monthly during daytime hours (07:00 – 19:00). It may be noted that there are currently no significant sources of ground-borne vibration at the station, nor are there any proposed.

During visits to the site and surrounding area by HGC Engineering personnel in November, 2018 and February, 2019, the background sound in the area was observed to be dominated by road traffic on Byron Baseline Road and other surrounding roadways. In that regard, the area is best categorized as a Class 1 ("urban") acoustical environment, under the applicable MECP noise assessment guideline (detailed in the following section).

The most potentially impacted noise-sensitive points of reception to the TS are single family dwellings located to the south, the nearest of which abuts the south TS property line and is labelled as location R1 in Figure 2. A residential subdivision, under construction east of Wickerson Road at the time of the last visit to the area by HGC Engineering, is labelled as location R2 in Figure 2. The lands west and north of the station are zoned for agricultural use, hosting no noise-sensitive uses.

Based on measurements conducted in February, 2019, the current sound levels of the station exceed the applicable MECP limit (detailed in Section 3.1) by up to 20 dBA at location R1, which was attributed to sound from the boilers, above-grade piping and metering/regulation equipment (all of which are currently located outdoors).

In response, Enbridge has expedited plans to upgrade the TS, and incorporated a number of features into the design aimed at reducing noise emissions, including locating the boilers and regulation equipment indoors, minimizing the gas volume flowing through the boiler system and 1st stage regulation cuts by splitting the flow path into parallel runs and heavier gauge/larger diameter gas piping.

3 CRITERIA

3.1 MECP Publication NPC-300

In Ontario, the MECP guideline that forms the basis of environmental noise assessment is publication NPC-300[1], which draws a distinction between "stationary sources" (industrial or commercial sounds), and other types of sources such as road traffic or construction activities, for example. The sound sources associated with the subject site are classified as stationary sources. The sound level limits for stationary sources of sound are site specific and depend on the background sound in the vicinity, which includes road traffic sound but excludes the source under assessment. The guideline also stipulates that the assessment consider the potential noise impact during a "predictable worst-case hour" of operation, which is defined as a situation when the normally busy activity of the source coincides with an hour of low background sound. In other words, the principle of assessment involves evaluating the subject source against the background sound, on an hourly basis. If the acoustic environment in the vicinity is such that the ambient sound level falls off significantly during quiet hours, there are exclusionary minimum sound level limits which set the lower bound for the acceptability criteria. Specifically, NPC-300 states that the sound level limit for a stationary source in a Class 1 environment is the greater of the minimum one-hour energy-equivalent ambient sound level (L_{EQ}) during any hour that the subject source may operate or the exclusionary minimum limits of 50 dBA during daytime/evening hours (07:00 to 23:00) and 45 dBA during nighttime hours (23:00 to 07:00).

Based on observations made during the site visits, it is expected that background sound levels in the vicinity of the station may fall as low as the exclusionary minimums outlined above during the quietest hours of the day and night. Because the station operates 24 hours per day, the key sound level limit applicable at the neighbouring homes is the most stringent nighttime limit of 45 dBA.

---

[1] Ontario Ministry of the Environment, Conservation and Parks Publication NPC-300, *Environmental Noise Guideline, Stationary and Transportation Sources - Approval and Planning*, August, 2013.

NPC-300 stipulates that sound emissions from emergency equipment (i.e. the onsite generator) operating in non-emergency situations, such as maintenance testing, be assessed independently of all other stationary sources of noise. Further, the sound level limits for emergency equipment are 5 dB greater than the limit otherwise applicable to stationary sources. As the emergency generator at the subject site will be tested during daytime hours, the applicable sound level limit is 55 dBA (5 dB greater than the daytime exclusionary minimum criterion of 50 dBA).

3.2 City of London By-Law PW-12-19004

Part 2 of City of London By-Law PW-12-19004, which "…provide[s] for the Regulation and Prohibition of Noise and Sound", includes a prohibition on "unreasonable noise, or a noise that is likely to disturb the inhabitants". Part 3 of the by-law adopts the quantitative noise standards of the MECP. (Note that the by-law cites MECP guideline NPC-205, which was superseded by NPC-300 in 2013.) With regard to the qualitative prohibition of noise that is unreasonable or likely to disturb inhabitants, a technical evaluation thereof within an engineering study of the future state of a site (sound emissions from which cannot be observed) is problematic. Therefore, for the purposes of this study, the quantitative limits of the MECP (cited in Part 3 of the by-law and detailed in section 3.1) are the salient evaluative criteria.

4 ACOUSTICAL ANALYSIS, RESULTS & DISCUSSION

The primary sources of sound at the upgraded TS will be the combustion exhausts of the boilers, ventilation openings in the regulation building, above-grade piping and the emergency generator. The locations of these sources are overlaid on the site plan, included as Figure 3.

The sound emissions levels of the boiler exhausts (a maximum of two will be operating at a given time, with the third redundant) were predicted using acoustical engineering formula based on boiler capacities of 1.75 MMBTU. Each of the two regulation buildings will have four ventilation openings: two on the west side and two on the east side. Sound emissions from these openings were predicted based on the room dimensions/finishes (which will include acoustical insulation affixed to the interior walls to minimize reverberation) and the layout of regulation equipment within, consisting of the following (sound emission data provided by Enbridge):

Table 1: Summary of Regulator Sound Emission Levels

Regulator Building		Total Number of Regulators	Number of Regulators Flowing at a Given Time	Sound Pressure Level at 1 m from Regulator(s) [dBA]
1		6	2	76
2	1st pressure cut	4	1	88
	2nd pressure cut	4	2	85/88

Sound emissions from the emergency generator were based on data provided by the manufacturer: 68 dBA at 7 metres (which includes the benefit of a sound attenuated enclosure).

Developing reliable predictions of sound emissions from above-grade gas piping is a considerable challenge, since it is a function of a multitude of variables including: gas flows/pressures, piping geometry (i.e. the locations and extent of bends, junctions, etc.), the locations and nature of in-flow mechanisms (e.g. valves and regulation equipment), pipe gauge and segment rigidity, etc. For the purposes of this exercise, sound emissions from above-grade piping in the upgraded state of the TS were based on the average sound emission level of all piping measured at the TS in February, 2019. This is a conservative representation, as it does not account for the heavier gauge piping or reduced flows of the upgraded design.

A computational acoustical model of the TS and surrounding area was developed using Cadna/A software, a computer implementation of ISO standard 9613-2[2], which accounts for reduction in sound level with distance due to geometrical spreading, air absorption, ground attenuation and acoustical shielding by intervening structures. The source sound emission levels outlined above were input to the model, in order to predict the future sound levels of the station at the neighbouring points of reception. The prediction results indicate that the combined sound levels of the boiler exhausts and regulator buildings will be reduced considerably, relative to the existing case, to more than 5 dBA below the MECP limit of 45 dBA. The sound level of the emergency generator, which is evaluated separately from the balance of onsite equipment, will be within the applicable MECP limit of 55 dBA provided that testing is limited to daytime/evening hours (between 07:00 and 23:00).

[2] International Organization for Standardization, "Acoustics – Attenuation of Sound during Propagation Outdoors – Part 2: General Method of Calculation," ISO-9613-2, Switzerland, 1996.

Adding the contribution of sound from above-grade piping to that of the boiler exhausts and regulator buildings, the sum sound levels of all non-emergency sources are predicted to exceed the MECP limit. However, as noted above, sound emissions from above-grade piping are challenging to accurately predict, and the analysis employed herein is conservative insofar as the upgraded station design incorporates heavier gauge piping and lower gas flow rates. Nevertheless, noise from above-grade piping has been reliably mitigated at similar stations throughout the Enbridge system, typically through the application of an acoustical insulation ("lagging") system to the piping and/or judicious placement and sizing of acoustical barriers. Acoustical lagging can provide a range of sound attenuation, depending on the configuration. Similarly, the attenuation afforded by an acoustical barrier depends on the location, height and extent, relative to the source(s). Supplementary acoustical modelling of the Byron TS demonstrates that a combination of acoustical lagging and a noise barrier can feasibly achieve compliance with the MECP limit, notwithstanding the conservative nature of the analysis.

5 CONCLUSIONS & RECOMMENDATIONS

The results of the acoustical analysis detailed in the previous sections indicate that the sound levels of the upgraded boilers and regulation equipment will be reduced considerably, relative to the existing equipment, to well below the applicable MECP limit at the neighbouring points of reception. Similarly, the sound level of the emergency generator will be within the applicable MECP limit provided that testing is limited to daytime/evening hours (between 07:00 and 23:00).

Given the uncertainty regarding future sound emissions from above-grade piping, it is premature to conclude that noise control measures are warranted, or to establish the extent of noise control (if any) that may be required in order for the sound levels of all non-emergency equipment to comply with the MECP limit. However, conservative analysis completed as part of this study confirms the feasibility of sufficient noise control measures for the TS.

It is recommended that detailed acoustical measurements be conducted of the upgraded TS at the earliest opportunity following commissioning, and under "worst case" conditions (which typically occurs during low ambient temperatures. After confirming the as-built sound emissions of the TS, the need for any noise control can be evaluated and, if required, a tailored noise control solution can be developed as part of the upgrade project.

Figure 1: Location Map

Figure 2: Satellite Image Showing Byron Transmission Station and Neighbouring Points of Reception

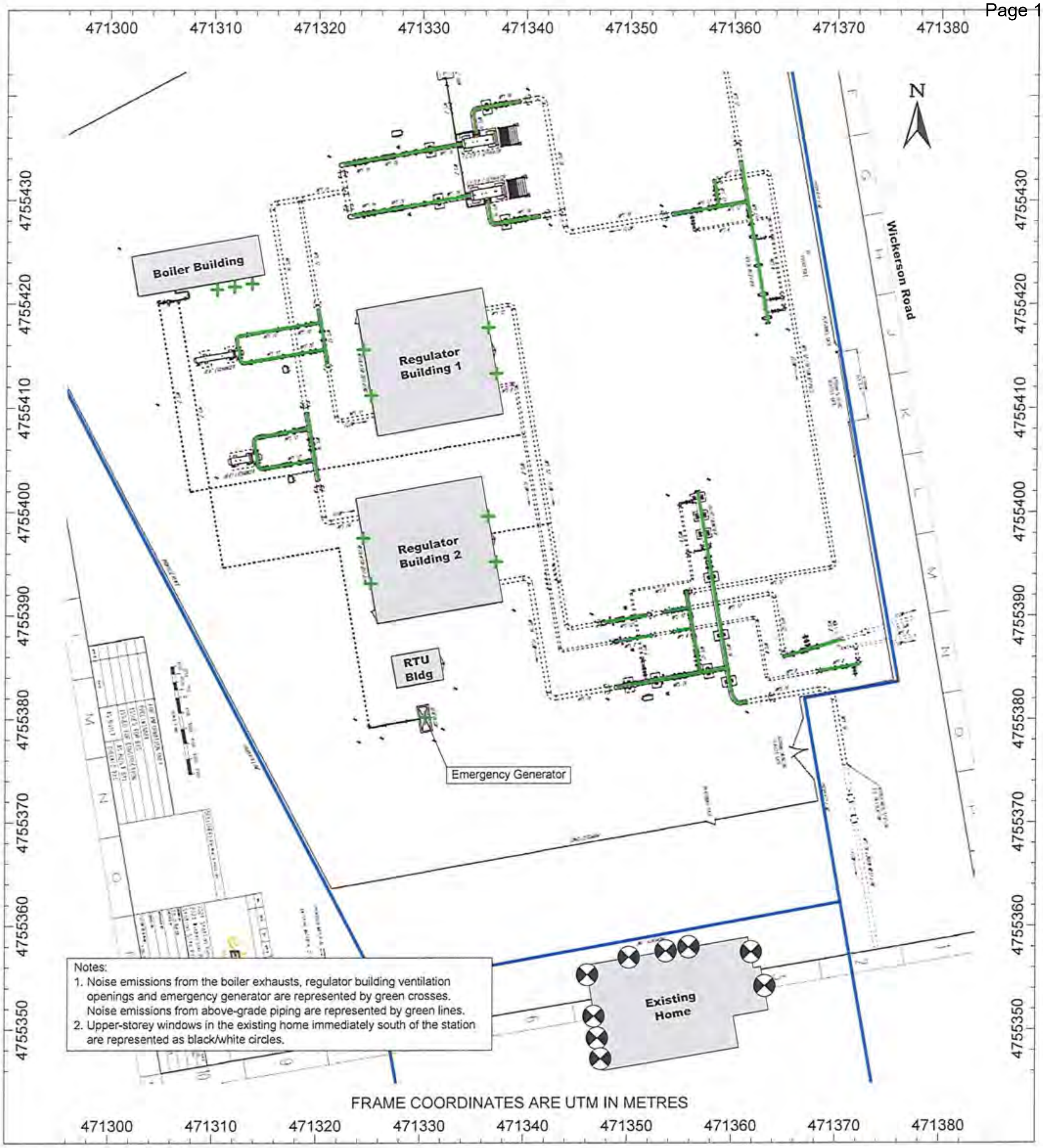
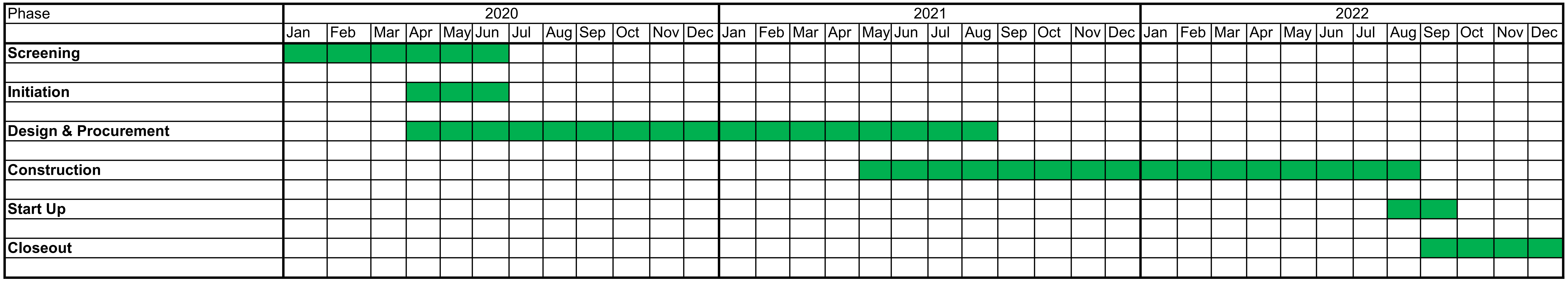


Figure 3: Byron Transmission Station Site Plan Showing Locations of Noise Sources

PROJECT SCHEDULE



ALTERNATIVES AND PROJECT DESCRIPTION

Summary of Alternatives

1. This evidence sets out the process and criteria used to select the alternative that best mitigates the Station concerns discussed in Exhibit B, while continuing to safely and reliably serve existing downstream distribution system demands.

2. When existing Enbridge Gas facilities have known integrity concerns, alternatives are generated to extend the useful life of the asset or replace the asset. All alternatives are preliminarily reviewed for feasibility, and practicable ones are organized into a key alternatives list. Each alternative on the key alternatives list is further evaluated in detail to make a final recommendation.

3. Criteria for selecting the best alternative may include, but are not limited to:
   - Economic feasibility
   - Construction feasibility
   - Capacity created
   - Reliability of supply
   - System integrity benefits

4. The Project is a full station rebuild while keeping the existing Station online to ensure that the Company can maintain reliable and safe delivery of natural gas supply volumes downstream of the Station through winter 2021/22. The following alternatives were identified and assessed:

   a) **Full station rebuild of the existing Byron Transmission Station with no land acquisition.**
   As land negotiation can be lengthy and costly, the project team investigated the feasibility of rebuilding the Station within the footprint of the existing site. However, it was determined that the existing site was not large enough to construct the new assets while keeping the existing Station in service.

Additionally, the construction duration was too long to accommodate the Station shut down without impacting security of supply. For these reasons this alternative was determined to be infeasible.

b) **Full station rebuild of the existing Byron Transmission Station with land acquisition.**
This alternative considered the purchase of 1.56 acres of additional land adjacent to the existing Station site in order to allow the new station to be constructed around the existing Station while maintaining continuous supply to the downstream distribution customers. This alternative resolves heater integrity concerns, noise complaints and compliance concerns, maintenance and operational concerns regarding equipment spacing and integrity concerns associated with Station inlet valves, and the inability for the existing Station to support the long term demands of the London, St Thomas and Port Stanley systems. For these reasons, this alternative was selected as the preferred alternative.

c) **Partial replacement of the station**
This alternative considered replacing components of the existing Station but was dismissed as the construction duration was too long to accommodate the Station shut down without impacting security of supply. In addition, this alternative would not mitigate all of the noise and maintenance and operational concerns with the existing Station. Variants of this alternative were also considered, including: (i) Replacement of heater systems and meters; and (ii) Replacement of the heater systems, meters and regulators. These variants were dismissed as viable alternatives because they required the installation of significantly larger heating systems and/or regulators compared to the preferred alternative, did not adequately address noise or ergonomic concerns identified, required temporary by-pass stations throughout Project construction; and provided inadequate

capacity to support longer term growth. For these reasons this alternative was determined to be infeasible.

d) **Move station to a new location**

This alternative considered relocating the Station to a different site, however, this required new 6,160 kPa MOP main extensions to reach the new location. While this option would presumably address the noise and maintenance and operational concerns with the existing Station, the preliminary cost of this alternative was expected to be higher than the Project and as such this alternative was determined to be infeasible.

Integrated Resource Planning (IRP)

5. At the time of Project development, the OEB had not yet established an IRP Framework for Enbridge Gas (EB-2020-0091). As is evident from the Project construction schedule filed at Exhibit B, Tab 1, Schedule 1, Attachment 2, the Project had been approved and was in the midst of being executed and constructed by the time that the OEB issued its Decision on the IRP Framework for the Company on July 22, 2021. Physical construction of the project started in May 2021 while design and procurement activities started in April 2020. Given the timing of Project development and as this Project deals with a station replacement primarily designed to address station integrity concerns, no formal IRP assessment was completed.

6. As discussed at Exhibit B, Tab 1, Schedule 1, the Project is driven by heater integrity concerns, noise complaints and compliance concerns, maintenance and operational concerns regarding equipment spacing and integrity concerns associated with Station inlet valves, and the inability for the existing Station to support the long term demands of the London, St Thomas and Port Stanley systems.

Facilities

7. The Project is a replacement of the entirety of the existing Station. The new Byron Transmission Station will be constructed around the existing assets while the Station remains in service. Once the construction of the new assets is complete, commissioning activities will commence. This will be completed in the summer months (mid-June to mid-September) of 2022 when natural gas demand is typically low, such that the downstream network can be supported by other nearby stations. Following the completion of Project construction and commissioning, the existing Station will be abandoned and removed from site.

8. The Project is mainly located on Enbridge Gas-owned lands. The adjacent land parcel on which components of the new station will be located has been purchased.

9. The Project involves station grading and landscaping, construction of retaining walls, removal of abandoned pipelines, installation of a storm water management solution, upgrading of electrical service, construction of new buildings for the new boiler system, new monitor/operator regulators, a new remote telemetry unit, installations of new meters, and new filter/separator. The upgraded station will also include a new natural gas-fired emergency power generator for increased reliability of the station and uninterrupted distribution to the networks in case of a power outage.

10. Due to the results of the 2019 Noise Impact Study found at Exhibit B, Tab 1, Schedule 1, Attachment 1, Enbridge Gas incorporated a number of features into the Project design aimed at reducing noise emissions, including: locating the boilers and regulation equipment indoors, minimizing the gas volume flowing through the boiler system and first-stage regulation cuts by splitting the flow path into parallel runs and heavier gauge/larger diameter gas piping.

11. The 2021 Noise Impact Study concluded that the sound levels of the upgraded boiler system and regulation equipment will be reduced considerably, relative to the existing

case, and within MECP limits. Similarly, the sound levels of the emergency generator are also predicted to be within the applicable MECP limit.

Timing

12. Enbridge Gas began construction on the new Byron Transmission Station in May 2021. Installation work will continue through 2021 and into 2022, with an anticipated in-service date of August 2022. Abandonment of the existing station and site restoration will occur later in 2022. The project schedule can be found at Exhibit B, Tab 1, Schedule 1, Attachment 2.

PROJECT COSTS AND ECONOMICS

Project Costs

1. The total estimated cost of the Project is $20.4 million as shown in Table 1 below. This cost includes: (i) materials; (ii) construction and labour; (iii) environmental protection measures; (iv) land acquisitions; (v) contingencies; (vi) interest during construction ("IDC"); and (vii) indirect overheads.

Table 1: Estimated Project Costs

Item No.	Description	Cost
1.0	Material Costs	$4,893,000
2.0	Contractor Labour Costs	$8,428,000
3.0	Internal Labour Costs	$180,000
4.0	Third Party Services	$1,111,000
5.0	Land Acquisition Costs	$277,000
6.0	Contingency Costs	$1,781,000
7.0	**Project Cost**	**$16,670,000**
8.0	Indirect Overheads	$3,648,311
9.0	IDC	$62,517
10.0	**Total Project Costs**	**$20,380,828**

2. The cost estimate set out above include a 12% contingency applied to all direct capital costs. This contingency amount is based on the current construction stage of the Project.

3. The cost estimate outlined above is a Class 1 estimate following the Cost Estimating and Management Standard. It is built using detailed contractor/third party estimates, actual materials and services purchase orders, and actual costs up to August 31, 2021, based on issued for construction drawings and site plan approvals.

4. The project cost has increased from the previous estimate reported in the Asset Management Plan.[1] This is largely due to: (i) reclassification of the cost estimate from a Class 5 estimate (based on historical project costs and rangeability of -50% to +100%) to a Class 1 estimate, (ii) increased civil scope based on Site Plan Approval consultations, (iii) increased scope due to land acquisition agreement; and (iv) increased construction labour costs as a result of project construction being spread over two years.

5. The method of construction will be trenching for pipeline and clearing and grading in preparation for the construction of the proposed station. The existing Station is being kept in service while new assets are being installed around the existing assets. Commissioning activities require both existing and new assets to be taken out of service for a period of time.

6. The cost estimate includes the cost of land purchase, removal of 600 m of previously abandoned pipelines from the adjacent land (as a condition of land purchase), and temporary working space easements.

<u>Project Economics</u>

7. A Discounted Cash Flow report has not been completed as the Project is underpinned by integrity requirements.

1 EB-2020-0181, Exhibit C, Tab 2, Schedule 1.

Business Case:

Kirkland Lake Lateral Replacement

EXHIBIT LIST

A – ADMINISTRATION

Exhibit	Tab	Schedule	Contents of Schedule
A	1	1	Exhibit List

B – PROJECT NEED

Exhibit	Tab	Schedule	Contents of Schedule
B	1	1	Project Need
			Attachment 1 – Kirkland Lake System Schematic
			Attachment 2 – 2019 ECDA
			Attachment 3 – Project Schedule

C – ALTERNATIVES & PROJECT DESCRIPTION

Exhibit	Tab	Schedule	Contents of Schedule
C	1	1	Alternatives & Project Description
			Attachment 1 – NPV Assessment of Alternatives

D – COST AND ECONOMICS

Exhibit	Tab	Schedule	Contents of Schedule
D	1	1	Project Costs and Economics

PROJECT NEED

Introduction

1. Enbridge Gas has identified the need to replace the existing NPS 4 Kirkland Lake Lateral ("Existing Line") running through the Municipality of Kirkland Lake in the District of Timiskaming with 8 km of NPS 4 pipeline (the "Kirkland Lake Lateral Replacement Project", "Proposed Pipeline" or "Project").[1] A full schematic of the Project is shown at Exhibit B, Tab 1, Schedule 1, Attachment 1.

2. The current system includes two lines, the Existing Line that is in scope for replacement, and a second NPS 8 Kirkland Lake Loop pipeline that runs in parallel to the Existing Line for the majority of the distance from the TransCanada Pipelines ("TCPL") supply station, located at Hwy 66 and Hwy 11 just south of Kenogami Lake, in a north-easterly direction for approximately 12 km to the south west end of the Municipality of Kirkland Lake. Each of the Existing Line and the parallel NPS 8 Kirkland Lake Loop operate at a maximum operating pressure ("MOP") of 6,895 kPag (1,000 psig). The NPS 4 Kirkland Lake Lateral was installed in 1958. The NPS 8 Kirkland Lake Loop was installed in 1990. Various sections, totaling approximately 4 km of the total 12 km of the Existing Line were replaced in 2018 for class location mitigation activity for High Consequence Areas ("HCAs"), most of which is located near Kirkland Lake (see Project Need – Condition of the Existing Line below for detail). Both of the Existing Line and the parallel NPS 8 Kirkland Lake Loop primarily feed the towns of Kirkland Lake, Chaput Hughes, Swastika and the Macassa Mines. The total number of customers being served by these pipelines is 3,126, including: residential, commercial, and large volume customers

[1] The Project was identified in Enbridge Gas's Asset Management Plan 2021-2025, EB-2020-0181, Exhibit C, Tab 2, Schedule 1, P. 561

(i.e., Macassa Mines and Kirkland Lake Generating Station, which in case of gas supply interruption would affect customers served by the generating station).

Project Need

Condition of the Existing Line

3. The Existing Line was installed in 1958 through a heavily forested region of northern Ontario with areas of very little soil. For much of the length of the Existing Line the pipeline runs through bedrock with blasted main bed and rocky backfill. Backfill has been subject to washouts and erosion, creating an abrasive environment for the pipeline as rock sediment contacts the pipe. Lack of cover for the pipeline is also a concern. Ground conditions for the Existing Line are set out in Figures 1 to 3 below.

Figure 1: Main Bed Conditions for the Existing Line

Figure 2: Backfill Conditions for the Existing Line

Figure 3: Pipeline Condition for the Existing Line

4. Enbridge Gas's Transmission Integrity Management Program ("TIMP") continually evaluates assets to identify risks and determine the condition of pipelines in the distribution network including for the Existing Line. Specifically, as part of Enbridge Gas's TIMP the Company has performed External Corrosion Direct Assessments ("ECDA") for the Existing Line, including:
   (i) a Close Interval Potential Survey ("CIPS");
   (ii) a DC Voltage Gradient ("DCVG") survey;
   (iii) an AC Voltage Gradient ("ACVG") survey;
   (iv) an AC Current Attenuation ("ACCA") inspection; and
   (v) a depth of cover survey to evaluate the integrity of pipeline coating by detecting coating faults from above ground, assessing their severity, and identifying areas where the probability of corrosion activity is elevated.

5. The Existing Line was inspected in 2007 resulting in 254 reportable indications and 17 required digs, 11 of which were immediate dig repairs. Similarly, in September of 2019 Enbridge Gas's Leak Inspection Survey of this pipeline found a loss of containment (corrosion through wall leak) location on the Existing Line. While this location was identified in the Company's 2007 ECDA studies and was deemed acceptable for monitoring at that time, by 2019 a through wall corrosion leak requiring immediate repair had developed. A subsequent ECDA inspection performed in 2019 found 8 locations with 9 immediate dig repairs (repairs required within approximately 18 months), with an additional 45 indications of locations requiring a scheduled repair (repairs required within approximately 48 months), and an additional 292 indications that required regular monitoring. This differs slightly from was what presented in the 2021-2025 Asset Management Plan.[2] The 2019 ECDA study classified 4 of the scheduled repairs as "high

[2] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, P. 561

priority", indicating it should be excavated as soon as possible. Enbridge Gas does not utilize this terminology and therefore reclassified those features as immediate dig repairs for the purposes of the Asset Management Plan Investment Summary Report. The 2019 ECDA report can be found at Exhibit B, Tab 1, Schedule 1, Attachment 2.

6. In total, 17 integrity digs have been conducted on the Existing Line. These digs identified a variety of anomalies, including coating holidays, external corrosion, arc burns, and linear indications in the long seam. 6 of the 17 integrity digs required the pipeline to be cut out to remediate discovered anomalies. The coating condition was found to be "poor" or "very poor" at 10 of the 17 dig sites.[3] Together, these integrity inspection results indicate that the Existing Line has reached the end of its useful life and should be replaced.

7. In the spring of 2021 Enbridge Gas also became aware of a significant washout of the cover over the Existing Line (likely the result of a failed beaver dam that released water down a slope towards the east side of the Blanche River crossing approximately 2 km west of Riverside Street in Swastika). The terrain to reach this location includes low lying wet, rocky and clay areas with hills at up to 13% incline and transitions to exposed rocky terrain near the Blanche River. The pipeline (with black tar coating) is exposed over the entire 23 m location of washout which is approximately 45 m east of the Blanche River. Figure 4 below provides images of the washout.

[3] Qualitative assessment of coating condition by ECDA consultant.

Figure 4: Washout of the Existing Line

8. Natural Gas Pipelines are installed to meet or exceed applicable minimum regulatory requirements at the time of construction. In some instances, cover may be altered due to excavation activities, erosion, construction, flooding, ground subsidence or other environment factors or human intervention. Over time this can increase the risk of third-party damages (constructors believing there is more cover than what is actually there) as well as damage due to the weight transfer of large vehicles and heavy equipment moving over top of the pipeline.

9. Depth of cover is another significant risk driver for the Existing Line. A depth of cover survey completed as part of the ECDA surveys in 2019 recorded measurements taken at regular intervals across the entire length of the Existing Line. A summary of this data is set out in Table 1. Specifically, Table 1 identifies

areas (approximately 1,336 m in total) of the Existing Line where incidents of reduced depth of cover are most likely to occur because the cover is less than 60 cm.[4] In at least one location (marked with an asterix in Table 1, approximate chainage 6020.8) the pipeline was visible on the surface with large rocks in direct contact with the topside of the pipeline (please also see Figure 5).

Figure 5: Exposed Pipeline Under Rock Boulders

[4] As per the CSA Z662-19, Sect 12.4.7, Table 12.2, the minimum requirement standard for pipe is 0.6 m.

Table 1 – Depth of Cover Findings Below 60 cm

Table 8: AREAS OF LOW COVER	
Approximate Chainage (m)	Feature Characteristics
404 to 429	Depth < 0.6m
1122 to 1151	Depth < 0.6m
2382 to 2449	Depth < 0.6m
2512 to 2529	Depth < 0.6m
2740 to 2824	Depth < 0.6m
3016 to 3065	Depth < 0.6m
3133 to 3155	Depth < 0.6m
3352 to 3380	Depth < 0.6m
3574 to 3650	Depth < 0.6m
3685 to 3747	Depth < 0.6m
3794 to 3850	Depth < 0.6m
4740 to 4832	Depth < 0.6m
5480 to 5600	Depth < 0.6m
5782 to 5850	Depth < 0.6m
5910 to 6054	Depth < 0.6m
6125 to 6220*	Depth < 0.6m
6814 to 6912	Depth < 0.6m
7105 to 7120	Depth < 0.6m
7217 to 7267	Depth < 0.6m
7665 to 7682	Depth < 0.6m
8564 to 8590	Depth < 0.6m
8675 to 8700	Depth < 0.6m
8820 to 8845	Depth < 0.6m
10395 to 10415	Depth < 0.6m
10475 to 10500	Depth < 0.6m

10. Meeting the minimum depth of cover requirement per the CSA Z662[5] provides protection for the pipeline from typical activities while providing sufficiently convenient access for Enbridge Gas maintenance and construction activities. Third-party damages trigger repair work which, as discussed in the section entitled "*Consequences of Failure*", is becoming increasingly resource-intensive, costly, and time-consuming.

Risk Based Assessment

11. For the Existing Line, a qualitative risk assessment was completed using the Company's Standardized Operational 7x7 risk matrix and following the Company's Framework Standard – Risk Management and the GDS Procedure Hazard Identification and Risk Assessment for Common Register. For the purposes of the risk assessment, the Existing Line was segmented into sections of comparable condition and applicable risk information was documented for each section, including: possible failure modes, causes, applicable controls and possible consequences. This information was subsequently used to assess the likelihood and consequence of each failure mode for each of the selected pipeline segments. The assessment was completed in a structured and systemic style using a "what if" workshop style approach.

12. As part of the preparation for the risk assessment, information on pipeline condition, operating conditions, associated customers, inspection, and repair

---

[5] Canadian Standards Association (CSA) standard Z662 provides guidance on when a pipeline operator should address pipeline integrity and condition concerns. It is the responsibility of the pipeline operator, in this case Enbridge Gas, to monitor the condition of its pipeline assets and compare the condition of those assets to the guidance set out in CSA Z662. Should the condition of a pipeline be such that it creates a risk pursuant to CSA Z662 guidance, the pipeline operator must address the condition of the pipeline. The Transmission Integrity Management Program at Enbridge Gas incorporates the guidance and requirements set out in CSA Z662 and the TSSA Code Adoption Document in addition to industry best practices and internal standards.

strategies at the time of the assessment were collected. The risk assessment was completed in two stages: (i) Risk Assessment; and (ii) Risk Endorsement.

a. In the Risk Assessment stage, workshops were held with various subject matter advisors and operations personnel to: (i) review information that was collected; (ii) divide the pipeline into segments; (iii) build out the risk scenarios; (iv) document existing controls; and (v) assess the unique risk of the Existing Line.
b. Once the assessment was completed, a Risk Endorsement meeting was held with a cross-functional team of key decision makers. The purpose of the meeting was to obtain endorsement of the risk assessment and recommendation on risk treatment. At the end of the meeting, the risk treatment decision was documented to support the asset management plan.

13. The Existing Line and parallel NPS 8 pipeline were determined to be primarily medium risk on the Enbridge Operational Risk Matrix. Several different failure modes were identified, the majority of which were assessed as a medium risk. The main risk drivers are Financial and Operational reliability (Customer Loss) risks, both ranked as medium. While the Existing Line is deemed a medium risk on the Company's Operational Risk Matrix, the decision to replace the Existing Line as opposed to maintain and repair was based on economic viability. The cost of the replacement project is significantly less expensive than the cost to repair and maintain. This is demonstrated in the alternatives analysis at Exhibit C, Tab 1, Schedule 1, Attachment 1.

Consequence of a Failure

14. The Existing Line operates over 30% of the specific minimum yield stress ("SMYS"), so a leak/rupture event is possible as a failure mode. The proposed pipeline will operate below 30% ("SMYS") and is made of higher strength

materials, significantly lowering the risk of failure and thereby reducing the pipeline stress, inherently making it safer.

15. Customer Loss is a significant consequence of failure, particularly for sections where the pipelines (the Existing Line and the parallel NPS 8 Kirkland Lake Loop) cannot be isolated independently to effectively manage customer outages on the system. Considering forecast customer demand and peak loading, a loss of containment leak and repair on the Existing Line may result in customer outages, as the NPS 8 Kirkland Lake Loop may not have sufficient capacity to support the Municipality of Kirkland Lake (Residential and Commercial customers), the Kirkland Lake Generating Station and Macassa Mines.

16. Further, a lightning strike of the Existing Line and subsequent potential for significant fires resulting from loss of containment could also create significant risk and damage, as the Existing Line passes through regions with very little opportunity for detection of fire.

17. The cost of leak repairs on the Existing Line have historically been elevated in comparison to other more residential pipelines due to the isolated and heavily forested location that the pipeline travels through. Naturally, moving equipment and people into the area to perform leak repairs on 6,560 kPa (1,000 psig) MOP pipelines comes at a significant cost. For example, the leak found in late 2019 cost Enbridge Gas approximately $310,000 to repair. With the large number of immediate, scheduled, and monitored indications (over 350 indications) there would be significant repair costs in the near term if Enbridge Gas pursued the repair/maintain scenario (Exhibit C, Tab 1, Schedule 1, Attachment 1).

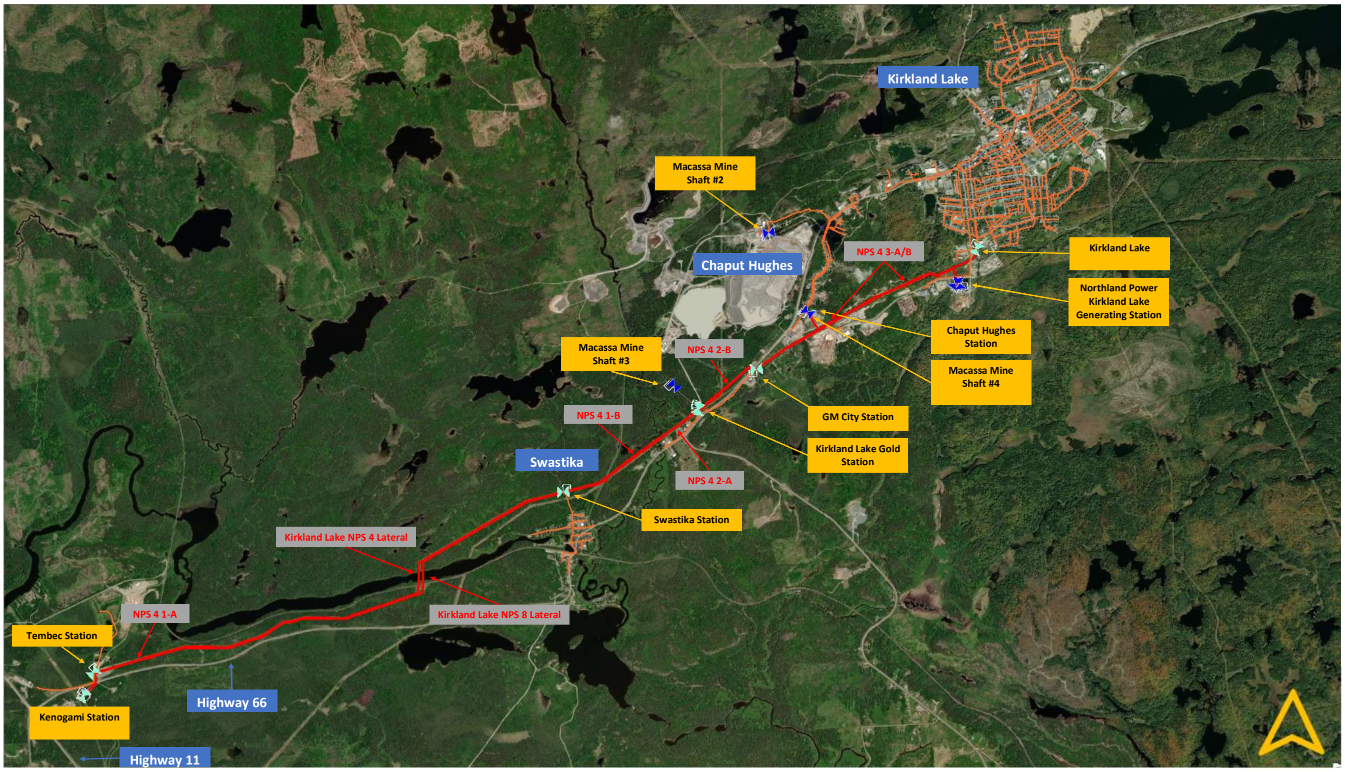
Recommendation for Pipeline Replacement

18. An analysis of pipeline replacement versus the cost to repair/maintain the Existing Line concluded that pipeline replacement provided the most certainty regarding risk reduction and had more economic viability. This is described further in Exhibit C, Tab 1, Schedule 1.

19. Based on the results of the Company's Integrity and Risk Assessment, Enbridge Gas has concluded that the Existing Lines are an operational risk, additionally due to the condition of the pipe, interim risk reductions have included an operating pressure restriction and increased leak surveys. As a result of the condition, risk, and maintenance costs, the Existing Lines should be replaced in order to maintain the safety and reliability of natural gas distribution to homes, businesses, institutions and other facilities in the Municipality of Kirkland Lake, the District of Timiskaming and surrounding areas.

Project Schedule

20. The project schedule is provided as Attachment 3 to this Exhibit.


Kirkland Lake
Macassa Mine Shaft #2
NPS 4 3-A/B
Chaput Hughes
Kirkland Lake
Northland Power Kirkland Lake Generating Station
Chaput Hughes Station
Macassa Mine Shaft #3
NPS 4 2-B
Macassa Mine Shaft #4
GM City Station
NPS 4 1-B
Kirkland Lake Gold Station
Swastika
NPS 4 2-A
Swastika Station
Kirkland Lake NPS 4 Lateral
NPS 4 1-A
Kirkland Lake NPS 8 Lateral
Tembec Station
Highway 66
Kenogami Station
Highway 11

AEGION
Stronger. Safer. Infrastructure.

corrpro

Mississauga Office
3-7895 Tranmere Drive
Mississauga Ontario, L5S1V9
Office: 905-677-2700
Fax: 905-677-2432

UNION GAS

KIRKLAND LAKE

ECDA INDIRECT INSPECTION REPORT

CORRPRO CANADA, INC.

1	ISSUED FOR REVIEW	AK	SD	MR	19-DEC-19
REV.	**DESCRIPTION**	**ORIG**	**RVW**	**APPD**	**DATE (DD-MMM-YY)**

December 20, 2019

Union Gas Limited
50 Keil Drive North
Chatham, ON N7M 5M1

ATTENTION: Scott McLean

RE: CORRPRO ECDA – EXTERNAL CORROSION DIRECT ASSESSMENT
INDIRECT INSPECTION REPORT FOR THE UNION GAS KIRKLAND LAKE PIPELINE

Please find enclosed the indirect inspection report for your review. This report is based on field surveys conducted in October 2019, on the NPS 4 Kirkland Lake pipeline owned by Union Gas Ltd.

Corrpro Canada, Inc. has appreciated the opportunity of completing this survey work on your behalf and looks forward to being of future service to you. If you have any questions regarding this report, please contact the undersigned.

Yours Respectfully,

CORRPRO CANADA, INC.

Mark Rozanski

Anthony Khoury
Engineer II
(416) 550-8953
Email: akhoury@aegion.com

Mark Rozanski
Project Manager II
(780) 991-9854
Email: mrozanski@aegion.com

TABLE OF CONTENTS

APPENDIX

1.0 EXECUTIVE SUMMARY

This 2019 indirect inspection was completed by Corrpro Canada, Inc. (Corrpro) on the NPS 4 Kirkland Lake pipeline. The total distance surveyed was approximately 12.3km, and the field work was conducted in the month of October 2019 by qualified Corrpro personnel.

The objective of the indirect inspection surveys was to collect and process data evidence on the integrity of the coating by detecting coating faults from above ground, assessing their severity, and identifying areas where the probability of corrosion activity is elevated. To this end, a Close Interval Potential Survey (CIPS), a DC Voltage Gradient (DCVG) survey, an AC Voltage Gradient (ACVG) survey, an AC Current Attenuation (ACCA) inspection and a depth of cover (DOC) survey were conducted on approximately 12,310 meters of pipeline. Soil resistivity measurements were also collected in multiple locations along the section of pipeline under study to allow for a more accurate analysis and prioritization of the anomalies detected.

The following cathodic protection (CP) and coating integrity concerns were identified during the inspections:

- A significant quantity of indications was detected on the surveyed line. In accordance with NACE SP0502 standards, nine (9) of the anomalies were prioritized as “Immediate action required”, and forty five (45) others as “Scheduled action required”, while almost three hundred (300) others were deemed “Suitable for monitoring”. The number of sites recommended for direct examination may have to be raised, depending on the results obtained by these examinations.
- Soil resistivity tests conducted during this inspection showed that all measurements exceeded 2000 ohm-cm, resulting in the soil corrosivity qualifying as a “minor indication”. This is relevant as it affects the anomaly prioritization process by significantly reducing the number of sites recommended for direct examination.

- The 2007 Kirkland Lake ECDA report provided by Union Gas also played a key role in the prioritization of indications. Regions where direct examination had revealed significant corrosion and wall thickness loss were deemed to be high risk regions. As a result, some anomalies, which would have otherwise been rated with a lesser priority, had their prioritization upgraded.
- The first stretch of approximately 540 meters beginning from the TCPL Kenogami station, showed severe DC interference where the pipe to soil potentials were consistently reverse shifting by over 60mV.
- Cumulatively, close to 2 km of the pipeline showed instant-off pipe to soil potentials below the minimum NACE cathodic protection criteria.

It should be noted that the terrain was frequently rocky, which caused difficulties with the quality of the readings. Furthermore, results of this survey present the CP levels and voltage gradients at the time of the survey and could change over time.

2.0 RECOMMENDATIONS

Appendix 2 contains more details on the anomalies mentioned below. In total, twelve (12) direct examinations are recommended to be completed as soon as possible. Note, regions designated in the pre-assessment have been redefined. For simplicity, the pipeline was split into four (4) regions based strictly on the chainage. Two (2) regions west of the river and another two on the east side of the river.

Table 1: ECDA Regions redefined

Region	Pipeline	Defining Characteristics
1	Kirkland Lake Lateral	Chainage 0 to 2000
2	Kirkland Lake Lateral	Chainage 2000m to 4300m (South side of the river)
3	Kirkland Lake Lateral	North side of the river from chainage 4470m to 8000m.
4	Kirkland Lake Lateral	Chainage 8000m to 12300m (end of line)

➔ The following eight (8) direct examinations are recommended at the sites of the anomalies which were prioritized as "Immediate action required" (Note that anomalies #182 and #183 were merged together for one direct examination site):

- **<u>Direct Examination #1,</u> Anomaly #4: "Minor DCVG" indication, chainage 228.5m, Immediate action required. Site coordinates: 48.09724824, -80.17877665. Estimated depth: 0.9m. Minor DCVG indication (%IR=32%) in conjunction with severe DC interference (ON = -1.129V and Instant-Off =-1.296V).** There are no details available as to the duration of time for which this section of pipe has been under heavy DC interference. This causes uncertainty regarding the extent of corrosion damage to expect at this location. However, the combination of a minor coating anomaly indication and the occurrence of the pipe to soil potentials being more electronegative when the rectifiers are interrupted (i.e. reverse-shifting), resulted in the anomaly being prioritized under "Immediate action required". The results obtained following this examination will determine whether more excavations are needed at the other anomalies detected in the stretch of pipe spanning from chainage 0 to approximately 540m, where the DC interference was observed. Repairing any coating damage found here would reduce stray current gain and reduce the risk of localized corrosion in other parts of the pipeline.

- **<u>Direct Examination #2,</u> Anomaly #14: "Severe DCVG", chainage 538.3m, Immediate action required. Site coordinates: 48.09841246, -80.1756487. Estimated depth: 0.7m. Severe DCVG indication (%IR=71.5%) located near a region experiencing severe DC interference.** Severe coating damage is expected at this location with possibility of pitting corrosion. The probability of localized pitting is raised by the presence of severe DC interference in proximity to this area. The duration of the DC interference is unknown and the possible duration ranges from 0 to 10 years (previous ECDA inspection time). This makes it impossible to accurately estimate the extent of corrosion. Furthermore, the pipe to soil potential values (which impact the %IR) have been manually selected in this location from the equipment's data log. This was necessary because the raw data shows the equipment was outputting contradicting data in the same position and the other inspection tools could not definitively eliminate the probability of coating damage in this location.

- **<u>Direct Examination #3,</u> Anomaly #35: "Severe CIPS/Moderate DCVG", chainage 1171.3m, Immediate action required. Site coordinates: 48.09979166, -80.16751809. Estimated depth: 1.1m. Severe CIPS indication, with an instant OFF potential reading of -0.593V, in conjunction with a moderate DCVG indication (%IR=42.4%).** Moderate coating damage with heavy pitting is expected at this location.

- **<u>Direct Examination #4,</u> Anomaly#50: "Severe CIPS/Moderate DCVG", chainage 1694.7m, Immediate action required. Site coordinates: 48.10006736, -80.16068175. Estimated depth: 1.5m. Severe CIPS indication, with an instant OFF potential reading of -0.600V, in conjunction with a moderate DCVG indication (%IR=46.6%).** Considering the soil resistivity is higher than 2000 ohm-cm at this location, the anomaly could have been prioritized as "Scheduled action required"; however, it is located in direct proximity to a region with severe prior corrosion (See DE#5 of 2007 ECDA report). As a result, the prioritization was upgraded to "Immediate action required". Significant coating damage and some pitting corrosion is expected at this location.

- **<u>Direct Examination #5,</u> Anomaly #78: "Severe CIPS/Moderate DCVG", chainage 2330.2m, Immediate action required. Site coordinates: 48.10102681, -80.15246941. Estimated depth: 2.2m. Severe CIPS indication with an instant OFF potential reading of -0.667V, in conjunction with a moderate DCVG indication (%IR=41.2%).** Similarly, to the previous anomaly, the prioritization was updated to immediate action required due to the proximity to a region with significant prior corrosion where over 70% wall loss was observed at some pits (See DE#6 of 2007 ECDA report). Moderate coating damage and severe pitting is possible at this location – however, it should also be noted that DE#1 of the 2007 ECDA report was also in direct proximity to this location and only showed superficial and minor pitting at that time.

- **Direct Examination #6, Anomaly #105: "Moderate DCVG/Moderate CIPS", chainage 3413.2m, Immediate action required. Site coordinates: 48.10256253, -80.13870272. Estimated depth: 0.8m. Moderate CIPS indication, with an instant OFF potential reading of -0.771V, in conjunction with a moderate DCVG indication (%IR=47.2%).** This anomaly was upgraded due to its direct proximity to a region with significant prior corrosion (See DE#2 of 2007 ECDA report). Moderate coating damage and moderate to severe pitting is expected at this location.

- **Direct Examination #7, Anomaly #182 and #183: "Severe DCVG/Severe CIPS" and "Severe CIPS/DC interference", chainage 6048.1m and 6053.7m, Immediate action required. Site coordinates: 48.11419012, -80.11089778. Estimated pipe depth: 1.0m. Severe CIPS indication, with an instant OFF potential reading of -0.645V, in conjunction with a severe DCVG indication (%IR=67.6%).** The gradient shift averages 30mV in this region and appears to be more electronegative when the rectifiers are in the OFF position. This may be due to some DC interference or it can be caused by an instrument error which is likely to occur when the gradient shifts are too small. Furthermore, a previous dig site located less than 100m away had revealed moderate corrosion. Heavy coating damage and moderate to severe pitting is expected at this location.

- **Direct Examination #8, Anomaly #222: "Severe CIPS/Moderate DCVG", chainage 6883.2m. Immediate action required. Site coordinates: 48.11568656, -80.09996028. Estimated depth: 0.4m. Severe CIPS indication, with an instant OFF potential reading**

of -0.493V, in conjunction with a moderate DCVG indication (%IR=48.18%). This anomaly was reprioritized due to the close proximity to a region with significant prior corrosion, and the presence of multiple coating anomaly indications nearby. Considerable coating damage and moderate to severe corrosion is expected at this location.

➔ The following four (4) additional direct examinations are also recommended for the near future. These are at sites of some anomalies prioritized as "Scheduled action required" which showed the most severe indications in their respective regions. In accordance with section 5.3.3 of NACE standard SP0502-2010, a direct examination must be performed at one scheduled indication per region; and if the external corrosion results reveal corrosion deeper than 20% of the original wall thickness, additional direct examinations are required.

- **<u>Direct Examination #9,</u> Anomaly #32: "Moderate ACCA/Severe CIPS", chainage 991.8m. Scheduled action required. Site coordinates: 48.09939085, -80.16976833. Estimated depth: 1.3m. Severe CIPS indication, with an instant OFF potential reading of -0.574V, in conjunction with a moderate ACCA indication (7.4mB/m).** Coating damage and some corrosion is expected at this location.

- **<u>Direct Examination #10,</u> Anomaly #93: "Severe CIPS/Moderate DCVG", chainage 2801.3m. Scheduled action required. Site coordinates: 48.10261278, -80.14679335. Estimated depth: 0.4m. Severe CIPS indication, with an instant OFF potential reading of -0.632V, in conjunction with a moderate DCVG indication (%IR=35.6%).** There is no history of previous excavations within approximately 500m of this site. Moderate coating damage and minor corrosion is expected at this location.

- **<u>Direct Examination #11,</u> Anomaly #242: "Severe CIPS/Moderate DCVG", chainage 7665.9m. Scheduled action required. Site coordinates: 48.11941184, -80.09125062. Estimated depth: 0.3m. Severe CIPS indication, with an instant OFF potential reading of -0.660V, in conjunction with a moderate DCVG indication (%IR=58.9%).** Coating damage and minor corrosion is expected at this location.

- **<u>Direct Examination #12,</u> Anomaly #262: "Severe CIPS/Moderate DCVG", chainage 8828.9m. Scheduled action required. Site coordinates: 48.12549365, -80.07864702. Estimated depth: 0.3m. Severe CIPS indication, with an instant OFF potential reading of -0.493V, in conjunction with a moderate DCVG indication (%IR=36.5%).** Coating damage and minor corrosion is expected at this location.

➔ This study has shown that the NPS 4 Kirkland Lake pipeline has significant cathodic protection and coating integrity issues. Note that, the 2007 ECDA report had estimated the remaining life of the line to be 11.8 years and Union Gas personnel has informed Corrpro that a leak was repaired in 2019 on this line. These are indications that the line needs special attention. As a result, Corrpro recommends that direct examinations be completed as soon as possible and that unprotected areas be provided with enough cathodic protection current to prevent/decelerate further corrosion of the buried pipe as soon as possible, and for the reassessment interval to be strictly kept under five (5) years.

3.0 SUMMARY OF TOP DEFICIENCIES

'**Table 2**' contains a shortlist of the most severe deficiencies which were detected and prioritized as "Scheduled" or "Immediate". The complete list of deficiencies detected, along with comments and their respective locations, is presented in Appendix 5. It is important to note that, having the combination of very rocky site conditions with the presence of a large quantity of anomaly signals, rendered the data "very noisy". Therefore, the DCVG data may be deemed unreliable in areas where no correlation can be identified with results obtained from the other indirect inspection tools. More specifically, the DCVG graphs appear to display an unusual number of negative gradients. Some troubleshooting with the inspection equipment manufacturers indicated that these areas with low confidence in the data may be disregarded, and that, following the main recommendations listed in this report would suffice to address the most urgent issues discovered throughout this survey study, and to provide adequate maintenance to the pipeline in question.

The prioritization process was completed in accordance with NACE standard SP0502; and the color code was applied to the severity of the indications as follows:

Color coding legend

Green	**Minor indication**
Yellow	**Moderate indication**
Red	**Severe indication**

Table 2: SUMMARY OF TOP DEFICIENCIES

Anomaly label	Approx. Chainage (m)	Instant OFF (V)	Coating			Prioritization
			ACVG (dB)	Atten (mB/m)	DCVG %IR	
1: Severe DC interference	0 to 538	-	-	-	-	**Scheduled**
4: Minor DCVG	228.5	-1.296	39.2	0.7	32.0%	**Immediate**
14: Severe DCVG	538.3	-1.210	40.6	0.0	71.5%	**Immediate**
32: Moderate ACCA / Severe CIPS	991.8	-0.574	49.0	7.4	2.2%	**Scheduled**
35: Severe CIPS/Moderate DCVG	1171.3	-0.593	46.2	0.3	42.4%	**Immediate**
49: Severe CIPS	1682.1	-0.563	48.3	0.5	8.0%	**Scheduled**
50: Severe CIPS/Moderate DCVG	1694.7	-0.600	50.4	0.6	46.6%	**Immediate**
69: Severe CIPS/Moderate ACVG	2177.2	-0.692	55.3	0.3	3.0%	**Scheduled**

Table 2: SUMMARY OF TOP DEFICIENCIES						
70: Severe CIPS/Moderate DCVG	2188.6	-0.680	53.9	1.5	35.2%	**Scheduled**
71: Severe CIPS	2195.3	-0.581	53.9	1.0	8.5%	**Scheduled**
72: Severe CIPS/Minor DCVG	2217.4	-0.674	56.0	1.0	20.0%	**Scheduled**
73: Severe CIPS	2224.7	-0.495	54.6	0.5	1.6%	**Scheduled**
77: Severe CIPS	2309.3	-0.639	58.8	0.5	4.0%	**Scheduled**
78: Severe CIPS/Moderate DCVG	2330.2	-0.667	57.4	0.8	41.2%	**Immediate**
82: Severe CIPS	2414.0	-0.647	51.1	0.0	12.3%	**Scheduled**
84: Shallow cover/Severe CIPS	2444.4	-0.676	45.5	0.3	9.6%	**Scheduled**
93: Severe CIPS/Moderate DCVG	2801.3	-0.632	46.2	0.5	35.6%	**Scheduled**
101: Severe CIPS/Shallow cover	3054.6	-0.685	46.9	0.0	0.6%	**Scheduled**
105: Moderate DCVG/Moderate CIPS	3413.2	-0.771	47.6	0.6	47.2%	**Immediate**
106: Severe CIPS/Minor DCVG	3433.0	-0.563	48.3	0.8	20.7%	**Scheduled**
107: Severe CIPS/Minor DCVG	3451.1	-0.687	48.3	0.4	18.8%	**Scheduled**
108: Severe CIPS/Moderate DCVG	3494.8	-0.692	49.7	1.4	38.8%	**Scheduled**
114: Severe CIPS	3612.8	-0.604	46.2	0.6	0.8%	**Scheduled**
117: Severe CIPS	3692.0	-0.654	45.5	0.2	8.9%	**Scheduled**
136: Severe CIPS/Minor DCVG	4694.6	-0.619	46.9	0.4	16.9%	**Scheduled**
147: Severe CIPS	4942.9	-0.690	43.4	0.5	10.4%	**Scheduled**
148: Severe CIPS/Moderate DCVG	4952.0	-0.557	43.4	0.2	49.9%	**Scheduled**
172: Severe CIPS/Minor DCVG	5785.2	-0.654	39.9	0.0	27.8%	**Scheduled**
175: Severe CIPS/Minor DCVG	5846.8	-0.543	40.6	0.5	27.2%	**Scheduled**
176: Severe CIPS	5898.4	-0.643	42.0	0.0	5.6%	**Scheduled**
179: Severe CIPS	5998.0	-0.549	41.3	0.4	0.0%	**Scheduled**
181: Severe CIPS	6031.7	-0.560	43.4	1.3	14.9%	**Scheduled**
182: Severe DCVG/Severe CIPS	6048.1	-0.645	43.4	0.8	67.6%	**Immediate**

Table 2: SUMMARY OF TOP DEFICIENCIES						
183: Severe CIPS/DC interference	6053.7	-0.698	42.7	1.1	4.8%	**Immediate**
186: Moderate DCVG/Minor CIPS	6112.2	-0.893	41.3	0.0	38.6%	**Scheduled**
187: Moderate CIPS	6159.9	-0.728	43.4	0.0	25.3%	**Scheduled**
197: Severe DCVG	6376.1	-1.038	36.4	0.2	69.0%	**Scheduled**
199: Severe CIPS/Minor DCVG	6425.4	-0.682	42.0	0.1	17.8%	**Scheduled**
217: Moderate DCVG/Moderate CIPS	6802.1	-0.757	32.2	0.8	35.7%	**Scheduled**
221: Moderate DCVG/Moderate CIPS	6865.1	-0.780	33.6	0.6	35.6%	**Scheduled**
222: Severe CIPS/Moderate DCVG	6883.2	-0.493	35.7	0.3	48.2%	**Immediate**
231: Moderate CIPS	7331.2	-0.757	35.7	0.0	8.8%	**Scheduled**
234: Severe CIPS/Minor DCVG	7419.2	-0.590	38.5	0.2	23.9%	**Scheduled**
235: Severe CIPS/Moderate DCVG	7449.2	-0.698	40.6	0.2	39.3%	**Scheduled**
236: Severe CIPS/Moderate DCVG	7462.0	-0.666	39.9	0.0	35.1%	**Scheduled**
242: Severe CIPS/Moderate DCVG	7665.9	-0.660	46.2	0.6	58.9%	**Scheduled**
243: Severe CIPS/Moderate DCVG	7681.5	-0.640	44.8	1.3	41.9%	**Scheduled**
257: Severe CIPS/Minor DCVG	8648.0	-0.692	48.3	0.1	16.6%	**Scheduled**
258: Severe CIPS	8657.6	-0.587	47.6	0.2	2.4%	**Scheduled**
262: Severe CIPS/Moderate DCVG	8828.9	-0.458	46.9	0.9	36.5%	**Scheduled**
286: Moderate DCVG	10041.2	-1.533	49.0	0.4	35.6%	**Scheduled**
287: Moderate DCVG	10106.1	-1.534	46.2	0.0	43.2%	**Scheduled**
308: Severe CIPS	10783.9	-0.657	44.1	0.0	4.3%	**Scheduled**
320: Severe DCVG/Minor CIPS	11011.3	-0.822	42.7	3.3	67.7%	**Scheduled**

4.0 INDIRECT INSPECTION THRESHOLDS

External Corrosion Direct Assessment (ECDA) is defined by the NACE International Standard Practice SP0502-2010 as a four-step continuous improvement process intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity where other inspection means may not be utilized. The four steps are as follows:

- Pre-Assessment: Thorough and comprehensive compilation of historic and current data to determine whether ECDA is feasible, define ECDA regions and select indirect inspection tools.
- Indirect Inspection: Aboveground inspections to identify and define the severity of coating faults, other anomalies and areas where corrosion activity may have or may be occurring.
- Direct Examination: The excavation of locations where coating flaws and or/corrosion are most likely, evaluation of severity and root cause analysis.
- Post-Assessment: Analyses of data collected from the previous three steps to access the overall effectiveness of the entire ECDA process and determine re-assessment intervals.

The following include standards set for anomaly prioritization in SP0502

- For each ECDA region, a minimum of one direct examination, two for the first ECDA, is required at the most severe non-Immediate indications.
- If no indications are identified, or during the first ECDA, a minimum of one direct examination is required in the ECDA region identified as most likely to have corrosion. If more than one region was identified, additional examinations should be considered.
- Include all “Immediate” indications for direct examination. First ECDA Requirement: Do not reprioritize “Immediate” indications.

- For subsequent assessments, reprioritize "Immediate" indications on an ECDA Region basis to a lower priority as appropriate following the examination criteria for the lower priority.
- If 20% or more wall loss is found at a "Scheduled" indication, continue to examine "Scheduled" indications in order of priority until at least two "Scheduled" indications exhibit less than 20% wall loss.
- Excavations must continue until a wall loss greater than 20% is found. If in Region 1 over 20% wall loss is found in both the "Scheduled" and most severe monitored indication, excavations of monitored indications must continue (in order of severity) until wall loss above 20% is no longer present.
- First ECDA Requirement: Do not reprioritize "Scheduled" indications.
- For subsequent assessments, if "Scheduled" indications are reprioritized, follow the examination criteria for the new priority. If any "Scheduled" indications are reprioritized to an "Immediate" priority, examine at least one more "Scheduled" indication (within that ECDA region) in addition to the requirements listed below.
- If multiple ECDA regions contain "Monitored" indication, but no "Immediate" or "Scheduled" indications, only one excavation is required, two for first ECDA, for all the regions, performed in the ECDA region identified as most likely for external corrosion in the Pre-Assessment Step.

To prioritize indications, NACE SP0502-2010 directs that "Immediate", "Scheduled" and "Monitored" indications be assessed to identify the following:

- **Immediate action required** - this priority category should include indications that the pipeline operator considers as likely to have ongoing corrosion activity and that, when coupled with prior corrosion, pose an immediate threat to the pipeline under normal operating conditions.

- **Scheduled action required** - this priority category should include indications that the pipeline operator considers may have ongoing corrosion activity but that, when coupled with prior corrosion, do not pose an immediate threat to the pipeline under normal operating conditions.

  Monitored action required - this priority category should include indications that the pipeline operator considers as having the lowest rate of ongoing or prior corrosion activity.

Table 3: PRIORITIZATION TABLE FOR EXCAVATION SELECTIONS

Environment Soil Resistivity (Ω-cm)	Coating Anomaly: DCVG %IR and/or ACVG/ACCA	Cathodic Protection – CP CIPS		
		C. Severe	B. Moderate	A. Minor
D. Severe	G. Severe	1. Immediate	2. Immediate	3. Scheduled
	H. Moderate	4. Immediate	5. Scheduled	6. Scheduled
	I. Minor	7. Scheduled	8. Scheduled	9. Monitored
E. Moderate	J. Severe	10. Immediate	11. Scheduled	12. Scheduled
	K. Moderate	13. Scheduled	14. Scheduled	15. Monitored
	L. Minor	16 Monitored	17. Monitored	18. Monitored
F. Minor	M. Severe	19. Immediate	20. Scheduled	21. Monitored
	N. Moderate	22. Scheduled	23. Monitored	24. Monitored
	O. Minor	25. Monitored	26. Monitored	27. Monitored

'**Table 3**' is used for anomaly ranking and prioritization, with baseline thresholds set to a three-tier classification system as per NACE SP0502:

- Severe: indications that the pipeline operator considers as having the highest likelihood of corrosion activity.
- Moderate: indications that the pipeline operator considers as having possible corrosion activity.
- Minor: indications that the pipeline operator considers inactive, or as having the lowest likelihood of corrosion activity.

'**Table 4**' summarizes these baseline thresholds:

Table 4: SEVERITY CLASIFICATION TABLE			
Indirect Inspection Technique	**Indication Severity**		
	Severe	**Moderate**	**Minor**
CP, CIPS	'True OFF' potentials more electro-positive than -700mV	'True OFF' potentials more electro-negative than -699mV but not more than -799mV	'True OFF' potentials more electro-negative than -799mV but not more than -899mV
Coating, DCVG	> 65%IR; anodic both 'ON' & 'OFF'	65% IR – 35%IR; cathodic 'ON', anodic or neutral 'OFF'	35% > cathodic both 'ON' & 'OFF'
Coating, ACVG*	> 75 dB	75 dB – 50 dB	50 dB >
Coating, ACCA*	> 13 mB/m	13 mB/m – 5 mB/m	5 mB/m >
Soil Resistivity	<500 Ω-cm	500 to 2000 Ω-cm	>2000 Ω-cm

*Or equivalent

Areas suspected of interference require different thresholds than the ones presented above. Indications of interference may be found from CIPS and DCVG potentials, AC and DC pipe to soil potentials and features suspected of transmitting large stray currents into soil. Measurement thresholds for considering interference include either of the following:

- Reverse shift of 30mV or higher when a DC current source is interrupted.
- Close interval total dip of 30mV in both 'ON' and 'OFF' DC pipe to soil potentials.
- AC pipe to soil potentials measured at a test location of over $1V_{AC}$.

'**Table 5**' is utilized for assessing corrosion where interference is suspected.

Table 5: PRIORITIZATION TABLE FOR INTERFERENCE MITIGATION

Indirect Inspection Technique	Ranking		
	Severe	**Moderate**	**Minor**
CP, 'True OFF' structure to soil potential	More electro-positive than -700mV	More electro-negative than -699mV but not more than -799mV	More electro-negative than -799mV but not more than -899mV
Current Direction, DCVG	Anodic both 'ON' & 'OFF'	Anodic or neutral 'OFF'	Cathodic both 'ON' & 'OFF'
Coating, DCVG/ACVG	ACVG and DCVG minor as per '**Table 4**'	ACVG and DCVG moderate as per '**Table 4**'	ACVG and DCVG severe as per '**Table 4**'
Soil Resistivity	AC Voltage (mV to soil) larger than 450% of Soil Resistivity (Ω.cm)	AC Voltage (mV to soil) larger than 90% of Soil Resistivity (Ω.cm) and smaller than 450% of Soil Resistivity	AC Voltage (mV to soil) smaller than 90% of Soil Resistivity (Ω.cm)

In pipelines where the elimination of all DC current and hence IR is not practical, a near ground (NG) far ground (FG) comparison can be used to measure the extent of the residual current. The procedure for this calculation can be found in NACE SP0207-2007 section 5.8. This technique can be used to make an engineering assessment of the size of the known IR and aid the proper assessment of corrosion. This method captures DC influences from all sources such as currents that are not caused by CP rectifiers including sacrificial anodes, DC transmission systems, DC motors and DC train systems. The threshold for NG-FG differences in 'Instant OFF' potentials is set to 10mV, above which 'Instant OFF' potentials will no longer be deemed to represent 'True OFF'.

In addition to the NG-FG method for 'True OFF' determination at each test post, a pipe-to-soil potential is recorded on a digital oscilloscope prior to beginning the survey to ensure there is no 120Hz ripple during the 'OFF' cycle.

5.0 SURVEY DATA & ANALYSIS

Because of the constant degradation of coatings and changes in the soil environment, pipelines need regular inspections, internally and externally, to ensure that the coating performance and integrity of the pipeline is maintained. Generally, the longer pipelines stay buried in the ground, the greater their propensity for corrosion damage. Buried pipeline coatings can degrade over time especially if they are put in service into an environment they were not designed for (they are exposed to excessive temperatures, pH, or chemicals, or encounter soil stress, mechanical damage and/or pressure reversals). In general terms, since it is difficult to guarantee the integrity of pipeline coatings to the end of their design life, continuous external and internal inspections are recommended and/or required by regulatory bodies.

Inspection work and integrity analysis can include the following objectives:

- To determine the pipeline locations / areas which have the highest propensity of corrosion.
- To determine the adequacy of pipeline cover and position with regards to geotechnical regulations and standards.
- To identify any foreign sources of interference.
- To issue a signed report based on the data acquired, which has been reviewed and assessed by an indirect inspection technology subject matter expert.
- To adhere to all applicable pipeline regulations, codes, and standards, namely:

  - CSA Z662-15 Oil and Gas Pipeline Systems.
  - Applicable Provincial Legislation such as the “Alberta Pipeline Act” or “Ontario Regulation O. Reg. 210 – Oil and Gas Pipeline Systems”.
  - SP0502-2010 NACE Standard Practice, External Corrosion Direct Assessment.

- SP0169-2013 NACE Standard Practice, Control of External Corrosion on Underground or Submerged Metallic Piping Systems.
- SP0207-2007 NACE Standard Practice, Performing Close-Interval Potential Inspections and DC Surface Potential Gradient Inspections on Buried or Submerged Metallic Pipelines.
- TM0109-2009 NACE Standard Test Method, Aboveground Inspection Techniques for the Evaluation of Underground Pipeline Coating Condition.
- TM0497-2002 NACE Standard Test Method Measurement Techniques Related to Criteria for Cathodic Protection.

5.1 INFLUENCING RECTIFIERS

All Union Gas rectifiers known to be influencing the Kirkland Lake line were listed in the Pre-Assessment report. 'Table 6' highlights each of these rectifiers and their outputs. Note that, a list of other foreign rectifiers in the vicinity were interrupted remotely by their respective owners and were cycling in sync with the Union Gas rectifier interruptions.

Table 6: SIMULTANEOUSLY INTERRUPTED RECTIFERS

Owner	Rectifier	Location	Voltage (V)	Current (A)
UGL	#879	48.095278, -80.1805	7.81	0.52
	#880	Distribution Lines	9.41	2.55
	#888	48.12268 -80.083787	3.6	0.6

5.2 GEOTECHNICAL ANOMALIES

In Canada, CSA Z662-15 is the primary code governing the operation of oil and gas pipelines. Excerpts from CSA Z662-15 are outlined below (see 'Table 7' below):

Table 7: DOC REGULATORY REQUIREMENTS (CSA Z662 TABLE 4.9)				
Location	**Type**	**Class**	**Normal Excavation m (in)**	**Rock Excavation m (in)**
General	LVP or Gas	Any	0.60 (24)	0.60 (24)
	HVP or CO2	1	0.90 (36)	0.60 (24)
	HVP or CO2	2, 3, or 4	1.20 (48)	0.60 (24)
ROW	Any	Any	0.75 (30)	0.75 (30)
Road *	Any	Any	1.20 (48)	1.20 (48)
Rail (cased)**	Any	Any	1.20 (48)	1.20 (48)
Rail (uncased)	Any	Any	2.00 (79)	2.00 (79)
Water Xing	Any	Any	1.20 (48)***	0.60 (24)
Drainage Ditch	Any	Any	0.75 (30)	0.60 (24)

* See Clause 4.8.3.1.
** Within 7 m of center of outside rail, measured at right angles to the centerline of the track.
*** Cover not less than 60 cm shall be permissible where analysis indicates the potential for erosion is minimal.

The shallow cover area is presented in 'Table 8' below. The depth of cover chart is presented in Appendix 2-2.

Table 8: AREAS OF LOW COVER	
Approximate Chainage (m)	**Feature Characteristics**
404 to 429	Depth < 0.6m
1122 to 1151	Depth < 0.6m
2382 to 2449	Depth < 0.6m
2512 to 2529	Depth < 0.6m
2740 to 2824	Depth < 0.6m
3016 to 3065	Depth < 0.6m
3133 to 3155	Depth < 0.6m
3352 to 3380	Depth < 0.6m

Table 8: AREAS OF LOW COVER	
Approximate Chainage (m)	**Feature Characteristics**
3574 to 3650	Depth < 0.6m
3685 to 3747	Depth < 0.6m
3794 to 3850	Depth < 0.6m
4740 to 4832	Depth < 0.6m
5480 to 5600	Depth < 0.6m
5782 to 5850	Depth < 0.6m
5910 to 6054	Depth < 0.6m
6125 to 6220*	Depth < 0.6m
6814 to 6912	Depth < 0.6m
7105 to 7120	Depth < 0.6m
7217 to 7267	Depth < 0.6m
7665 to 7682	Depth < 0.6m
8564 to 8590	Depth < 0.6m
8675 to 8700	Depth < 0.6m
8820 to 8845	Depth < 0.6m
10395 to 10415	Depth < 0.6m
10475 to 10500	Depth < 0.6m

*In at least one location (approx. chainage 6020.8) the pipe was visible on the surface with big rocks in direct contact to the topside of the pipeline.

5.3 CATHODIC PROTECTION

Cathodic protection is used to control the external corrosion of buried pipelines by making the surface of a buried pipeline the cathode of an electrochemical cell. The simple principle is to make the potential of the whole pipeline external surface sufficiently negative with respect to the surrounding environment to ensure no current flows from metal to the environment. This can be accomplished by forcing an electric current to flow through the electrolyte towards the pipeline, thereby eliminating the anodic area. 'Table 9' below depicts the general relationship between pipe-to-soil potentials and corrosion of buried steel.

Please note, there are many variables that can affect propensity for corrosion, therefore 'Table 9' should be used as a general guideline rather than absolute permanent thresholds.

Table 9: POTENTIAL AND CORROSION OF BURIED STEEL	
Potential (V vs. Cu/CuSO4)	**Corrosion Condition**
-0.5 to -0.6	Intense Corrosion
-0.6 to -0.7	Corrosion
-0.7 to -0.8	Slow Corrosion
-0.8 to -1.4	Cathodic Protection
-1.4 and above	Overprotection (disbonding of coatings, hydrogen blistering), at potentials above -1.7 Vcse, severe overprotection is possible.

The criterion implemented for assessing the effectiveness of pipeline cathodic protection (CP) system is derived from the NACE Standard Practice SP0169-2013. The two protection requirements outlined in this standard are:

- -850 mV/CSE INST OFF: A negative polarized (instant 'OFF') potential of at least -850 mV/CSE. This is the most common criterion and if all CP sources can be interrupted, it will provide a detailed assessment of whether the pipeline is protected or not protected with CP current.
- 100 mV DEPOL: A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. Provides the most accurate indication of CP protection on a metallic structure.

Union Gas Ltd. has its own cathodic protection standard of -1000mV/CSE ON; this criterion was considered during Corrpro's CP survey and is depicted in the survey charts in Appendix 2. In addition, close interval potential graphs are studied for patterns displaying "peaks" and "dips" over distances, corresponding to current density at the pipe-soil interface and pipeline conditions. These potential movements signal the presence of influences that may be detrimental to pipeline integrity, such as coating defects, foreign interference and isolation. A change of 30mV in potential from pattern top to pattern bottom is taken as the threshold for further investigation. CIPS graphs are interpreted in accordance with NACE SP0207-2007.

'Table 10' lists the CP deficiencies found throughout this investigation.

Table 10: CATHODIC PROTECTION DEFICIENCIES

Anomaly label	Instant OFF (V)	Approximate Chainage (m)
30: Minor CIPS	-0.898	951.9
31: Minor DCVG/Minor CIPS	-0.875	970 to 1009
32: Moderate ACCA / Severe CIPS	-0.574	
33: Moderate ACCA / Minor CIPS	-0.869	
35: Severe CIPS/Moderate DCVG	-0.593	1164 to 1176
45: Moderate CIPS/Minor DCVG	-0.760	1541 to 1563
47: Moderate DCVG/Minor CIPS	-0.820	1595 to 1623
49: Severe CIPS	-0.563	1664 to 1817
50: Severe CIPS/Moderate DCVG	-0.600	
51: Moderate CIPS/Minor DCVG	-0.797	
53: Moderate DCVG/Minor CIPS	-0.854	
66: Minor CIPS	-0.872	2098 to 2233
68: Moderate ACVG/Minor CIPS	-0.856	
69: Severe CIPS/Moderate ACVG	-0.692	
70: Severe CIPS/Moderate DCVG	-0.680	
71: Severe CIPS	-0.581	
72: Severe CIPS/Minor DCVG	-0.674	
73: Severe CIPS	-0.495	

Table 10: CATHODIC PROTECTION DEFICIENCIES		
Anomaly label	Instant OFF (V)	Approximate Chainage (m)
75: Moderate DCVG/Moderate CIPS	-0.751	2259 to 2346
76: Moderate CIPS/Minor ACCA	-0.777	
77: Severe CIPS	-0.639	
78: Severe CIPS/Moderate DCVG	-0.667	
79: Moderate ACCA/Moderate CIPS	-0.772	
82: Severe CIPS	-0.647	2382 to 2449
83: Moderate CIPS	-0.756	
84: Shallow cover/Severe CIPS	-0.676	
85: Minor DCVG/Minor CIPS	-0.892	2496 to 2513
86: Moderate DCVG/Minor CIPS	-0.896	
90: Minor CIPS	-0.856	2683 to 2694
93: Severe CIPS/Moderate DCVG	-0.632	2785 to 2810
94: Moderate CIPS/Minor DCVG	-0.750	
95: Minor DCVG/Minor CIPS	-0.881	2833
97: Moderate CIPS	-0.793	2848 to 2865
100: Moderate CIPS/Minor DCVG	-0.784	3031 to 3060
101: Severe CIPS/Shallow cover	-0.685	3016 to 3065
105: Moderate DCVG/Moderate CIPS	-0.771	3408 to 3508
106: Severe CIPS/Minor DCVG	-0.563	
107: Severe CIPS/Minor DCVG	-0.687	
108: Severe CIPS/Moderate DCVG	-0.692	
112: Moderate CIPS	-0.731	3561 to 3747
113: Moderate CIPS	-0.716	
114: Severe CIPS	-0.604	
115: Moderate CIPS	-0.705	
116: Minor CIPS	-0.840	
117: Severe CIPS	-0.654	
118: Moderate CIPS	-0.748	
119: Minor DCVG/Minor CIPS	-0.803	
120: Minor CIPS	-0.809	3829.9

Table 10: CATHODIC PROTECTION DEFICIENCIES		
Anomaly label	Instant OFF (V)	Approximate Chainage (m)
121: Moderate CIPS	-0.787	3843.6
126: Moderate CIPS	-0.794	4500 to 4515
129: Minor DCVG/Minor CIPS	-0.854	4585 to 4610
130: Moderate CIPS	-0.792	4632 to 4720
132: Moderate CIPS	-0.797	
133: Minor DCVG/Minor CIPS	-0.880	
135: Moderate CIPS/Minor DCVG	-0.729	
136: Severe CIPS/Minor DCVG	-0.619	
137: Moderate CIPS/Minor DCVG	-0.739	
141: Minor DCVG/Minor CIPS	-0.895	4819 to 5019
146: Moderate CIPS/Minor DCVG	-0.710	
147: Severe CIPS	-0.690	
148: Severe CIPS/Moderate DCVG	-0.557	
149: Minor DCVG/Minor CIPS	-0.816	
162: Minor DCVG/Minor CIPS	-0.858	5466 to 5510
163: Moderate CIPS/Minor DCVG	-0.744	
164: Minor DCVG/Minor CIPS	-0.859	
165: Minor DCVG/Minor CIPS	-0.895	
167: Minor CIPS	-0.887	5596.8
170: Minor CIPS	-0.873	5746.9
172: Severe CIPS/Minor DCVG	-0.654	5773 to 5797
173: Minor DCVG/Minor CIPS	-0.835	
174: Minor DCVG/Minor CIPS	-0.856	5825 to 5904
175: Severe CIPS/Minor DCVG	-0.543	
176: Severe CIPS	-0.643	

Table 10: CATHODIC PROTECTION DEFICIENCIES		
Anomaly label	Instant OFF (V)	Approximate Chainage (m)
179: Severe CIPS	-0.549	5985 to 6073
181: Severe CIPS	-0.560	
182: Severe DCVG/Severe CIPS	-0.645	
183: Severe CIPS/DC interference	-0.698	
186: Moderate DCVG/Minor CIPS	-0.893	6112 to 6116
187: Moderate CIPS	-0.728	6159.9
188: Minor CIPS	-0.861	6171.6
190: Minor CIPS	-0.831	6234.9
192: Minor CIPS	-0.890	6252.7
194: Minor CIPS	-0.889	6281
199: Severe CIPS/Minor DCVG	-0.682	6413 to 6478
201: Minor ACCA/Minor CIPS	-0.865	
202: Moderate CIPS/Minor DCVG	-0.764	
203: Moderate CIPS	-0.709	
211: Moderate CIPS	-0.715	6638 to 6652
214: Minor DCVG/Minor CIPS	-0.853	6759.2
215: Minor DCVG/Minor CIPS	-0.861	6775 to 6865
216: Minor DCVG/Minor CIPS	-0.891	
217: Moderate DCVG/Moderate CIPS	-0.757	
218: Moderate DCVG/Minor CIPS	-0.817	
219: Minor DCVG/Minor CIPS	-0.887	
220: Minor DCVG/Minor CIPS	-0.880	
221: Moderate DCVG/Moderate CIPS	-0.780	
222: Severe CIPS/Moderate DCVG	-0.493	6883 to 6896
224: Minor CIPS/Minor DCVG	-0.809	6916 to 6924
227: Minor CIPS	-0.867	7247 to 7250
231: Moderate CIPS	-0.757	7331.2

Table 10: CATHODIC PROTECTION DEFICIENCIES		
Anomaly label	Instant OFF (V)	Approximate Chainage (m)
234: Severe CIPS/Minor DCVG	-0.590	7402 to 7472
235: Severe CIPS/Moderate DCVG	-0.698	
236: Severe CIPS/Moderate DCVG	-0.666	
242: Severe CIPS/Moderate DCVG	-0.660	7665 to 7681
243: Severe CIPS/Moderate DCVG	-0.640	
254: Minor CIPS	-0.865	8573 to 8578
255: Moderate CIPS/Moderate DCVG	-0.776	8603.7
256: Minor CIPS	-0.800	8616.6
257: Severe CIPS/Minor DCVG	-0.692	8631 to 8685
258: Severe CIPS	-0.587	
259: Moderate CIPS	-0.743	
261: Minor CIPS	-0.818	8779 to 8785
262: Severe CIPS/Moderate DCVG	-0.458	8812 to 8846
307: Moderate DCVG/Moderate CIPS	-0.794	10769 to 10798
308: Severe CIPS	-0.657	
320: Severe DCVG/Minor CIPS	-0.822	10999 to 11012

Cumulatively, nearly 2km of the pipeline showed instant-off pipe to soil potentials below the minimum NACE cathodic protection criteria.

5.4 COATING ANOMALIES

A pipeline anomaly is any deviation from nominal conditions in the external wall of a pipe, its coating or electromagnetic conditions around the pipe. Anomalies may or may not have corresponding wall loss (i.e. corrosion). A coating anomaly is a classification given to any tested segments of pipe indicating imperfection in the coating based on collected data including disbonded areas and holidays. DCVG, ACVG and ACCA are coating assessment surveys and all detect voltage gradients and/or current attenuation within the ground.

Coating anomalies cannot be referred to as holidays or faults until the pipe is exposed and the holiday or fault is confirmed. This is because numerous phenomena can cause responses not related to coating faults of active corrosion. Interference, shielding and non-homogenous soils can all contribute to inspection technique responses and thresholds for detection.

'Table 11' presents the top 20 largest DCVG indications identified in this survey. In total, over 250 coating indications were detected. All possible anomalies are tested and filtered as per NACE TM109-2009 and SP0207-2007, to only present anomalies that can't be ruled out. This process involves removing scatter, adjusting for interference, removing magnetic field distortion, spanning gradients and using measurements from nearby features to rule out measurement errors.

Appendix 5 lists the complete list of coating indications identified and processed.

Table 11: COATING DEFICIENCES

Anomaly Label	Approx. Chainage (m)	ACVG (dB)	Atten (mB/m)	DCVG (%IR)	Latitude	Longitude
14: Severe DCVG	538.3	40.6	0.0	**71.5%**	48.09841246	-80.1756487
197: Severe DCVG	6376.1	36.4	0.2	**69.0%**	48.11482118	-80.10661865
320: Severe DCVG/Minor CIPS	11011.3	42.7	3.3	**67.7%**	48.13480421	-80.05372422
182: Severe DCVG/Severe CIPS	6048.1	43.4	0.8	**67.6%**	48.11419012	-80.11089778
242: Severe CIPS/Moderate DCVG	7665.9	46.2	0.6	**58.9%**	48.11941184	-80.09125062
223: Moderate DCVG	6912.0	35.0	0.4	**58.8%**	48.11574009	-80.09958463
333: Moderate DCVG	11865.2	53.9	0.2	**58.7%**	48.13712268	-80.04310764
63: Moderate DCVG	2008.1	54.6	1.3	**58.6%**	48.10020946	-80.15659708
233: Moderate DCVG	7389.4	33.6	0.0	**58.5%**	48.11807547	-80.09428228
239: Moderate DCVG	7590.3	42.7	0.2	**57.1%**	48.11911582	-80.09213137
138: Moderate DCVG/Suspect-anode	4727.9	46.2	0.3	**56.0%**	48.10860948	-80.1264212

Table 11: COATING DEFICIENCES						
Anomaly Label	**Approx. Chainage (m)**	**ACVG (dB)**	**Atten (mB/m)**	**DCVG (%IR)**	**Latitude**	**Longitude**
346: Moderate DCVG	12295.7	70.0	0.0	**54.5%**	48.13917361	-80.03869042
198: Moderate DCVG	6389.2	32.2	0.3	**54.2%**	48.11484164	-80.10644669
342: Moderate DCVG	12171.0	63.7	1.0	**53.3%**	48.13824949	-80.0394179
54: Moderate DCVG	1860.1	45.5	0.2	**53.0%**	48.1000099	-80.15851544
232: Moderate DCVG	7361.8	40.6	0.0	**52.5%**	48.11796238	-80.09460957
307: Moderate DCVG/Moderate CIPS	10773.5	44.8	0.2	**52.5%**	48.13387548	-80.05657465
296: Moderate DCVG	10452.9	42.0	0.3	**51.7%**	48.13252854	-80.06036951
317: Moderate DCVG	10977.6	43.4	0.0	**51.4%**	48.13469915	-80.05414566
148: Severe CIPS/Moderate DCVG	4952.0	43.4	0.2	**49.9%**	48.10955138	-80.12378002

5.5 SOIL RESISTIVITY

Many correlations between the characteristics of a soil and its corrosivity have been found through research and practical experience. Since corrosion requires movement of ions through the electrolyte, factors that increase the electrical conductivity of the soil tend to increase its corrosivity. Thus, higher moisture content, oxygen content, poor drainage, and high salt content tends to increase corrosivity. Differences in the characteristics of the soil from place to place along a pipeline, as well as from top to bottom can influence the rate of external corrosion. Coating anomalies can create corrosive environments since ions are attracted to exposed metal surfaces, water (polar molecule) accumulates in these locations due to the osmotic gradient, and the pipeline ditch tends to keep these accumulations from draining away.

'Table 12' provides a rough guideline to the correlation between soil resistivity and risk of external corrosion for an unprotected pipeline with a significant exposed pipe to soil contact area. As depicted in '**Table 3**', there are several factors which need to come into play for external corrosion to ensue, a highly corrosive electrolyte alone cannot establish a forgone conclusion that a pipeline is actively corroding.

Table 12: RESISTIVITY AND CORROSION OF BURIED STEEL	
Soil Resistivity (Ohm-cm)	**Potential Corrosivity Rating**
20,000+	Non-Corrosive (Fresh Water, Sand, Gravel)
10,000 to 20,000	Mildly Corrosive (Peat, Loam, Mud)
5,000 to 10,000	Moderately Corrosive (Clay, Sand Mixture)
2,000 to 5,000	Corrosive (Clay)
1,000 to 2,000	Highly Corrosive (Saturated Clay, Spring Water)
1,000 and Less	Extremely Corrosive (Sea Water)

A 4-pin Wenner test was conducted at several locations across the two sections under study. 'Table 13' presents the soil resistivities that were measured. Determining these resistivities is critical in assigning each anomaly with an appropriate excavation priority. Resistivity depths/pin spacings were fixed at 1m, 3m and 5m intervals. As seen in the table below, the measured soil was found to be ranging from corrosive to extremely corrosive, with resistivities between 800 and 5000 ohm-cm recorded.

Table 13: SOIL RESISTIVITY INSPECTION RESULTS						
Chainage (m)	**Latitude**	**Longitude**	**Soil Resistivity (ohm-cm)**			**Comments**
			Depth 1m	**Depth 3m**	**Depth 5m**	
425	48.098259	-80.177125	**123000**	127000	360000	Minor
1600	48.099984	-80.162167	**83800**	132000	225000	Minor
6500	48.114924	-80.104712	**207000**	128000	121000	Minor
7700	48.119444	-80.090703	**17600**	4880	11100	Minor
9150	48.127512	-80.075301	**41600**	69800	93300	Minor
12200	48.138925	-80.039147	**12400**	4050	3680	Minor

5.6 AC VOLTAGE

AC voltages were collected at each location where the soil resistivity was measured to assess the propensity for AC corrosion and interference across the lines. It should be noted that AC current density was calculated based on a 1 cm^2 holiday surface area. 'Table 14' highlights the collected AC voltages and raises no indication that AC corrosion should be expected at any of these locations since the AC current density does not exceed 20 A/m^2. Based on the combination of the AC voltage inspection results, measured soil resistivities, and the criteria established in '**Table 5**', there is no risk of AC voltage related interference.

Table 14: AC VOLTAGE INSPECTION RESULTS

Chainage (m)	Latitude	Longitude	Soil Resistivity (ohm-cm)	AC Voltage (V)	AC Current Density (A/m^2)	Comments
425	48.098259	-80.177125	123000	0.9	**1.7**	No risk
1600	48.099984	-80.162167	83800	0.2	**0.5**	No risk
6500	48.114924	-80.104712	207000	0.6	**0.7**	No risk
7700	48.119444	-80.090703	17600	0.3	**3.8**	No risk
9150	48.127512	-80.075301	41600	3	**16.3**	No risk
12200	48.138925	-80.039147	12400	0.8	**14.5**	No risk

5.7 CASING TESTING

The potentials of two (2) casings were measured during the surveys and it was determined that the casings are not shorted to the pipe at those locations.

Table 15: Casing testing data

Chainage	Pipe Potentials (-mV)		Casing Potentials (-mV)		Test station
	ON	OFF	ON	OFF	
4636.4	1750	1500	550	550	TB13
7065.9	1530	1220	980	980	TP18

5.8 INTERFERENCE

In CP, the term interference refers to electrical interference between two structures caused by a transfer of electrical or ionic current in and out of soil. Hence, interference is typically detectable using electrical and CP measurement techniques. There are two primary types of interference.

5.8.1 TIME DEPENDENT

Time dependent interference does not occur over a specific influencing area but rather, it varies with time. There are three common types of time dependent interference:

- Temporal
- Tidal
- HVDC, DC Traction

A Stationary data logger (SDL) was set up at Kenogami station, and CP data was measured continuously at those locations as the pipeline survey progressed. The SDL data is reviewed post inspection and if identified, corrections may be warranted. 30 mV fluctuations in 'ON' & 'Instant OFF' potentials are set as the threshold for suspecting stray current.

Based on SDL data collected, potential fluctuations exceeding 100mV are clearly observed which indicates that time dependent interference is present. Note also that the potentials in the area where this SDL was installed were more electronegative when the rectifiers were in the OFF position, indicating presence of DC interference, which is likely to be caused by a foreign rectifier in the area.

A sample of SDL data collected while surveying the Kirkland Lake line is provided in Appendix 2-3.

5.8.2 TIME INDEPENDENT

Time independent interference can be identified within the survey data and it is common for field technicians to identify the interference while surveying the pipeline. There are two common types of time independent interference:

- Impressed Current
- HVAC

These types of interference occur over a specified influencing area and can be detected through electrochemical analysis. In the CIPS data, dips in the close interval potentials over a survey distance can be a sign of DC current loss or a sudden lowering of current gain caused by changes in the pipe-soil interface, while peaks in close interval potential over a survey distance can indicate DC current gain. Using knowledge of current sources in the region and the shift cycle attributed to different current sources, a map of the underground current conditions may begin to form.

To assess outside DC influences on the pipeline, Near Ground (NG) and Far Ground (FG) measurements are collected at adjacent test posts where within the scope of the survey to help assess left over DC current. With this method, elaborated in NACE SP0207-2007, one can account for and estimate interfering DC current sources, including anodes and DC power/transmission systems. The Metallic IR Drop is the difference in the pipeline potential from the far test station (FG) to the near test station (NG). If the 'Instant OFF' metallic IR drop exceeds 10 mV, the collected potentials will be deemed not to represent 'true OFF' potentials.

Figure 5.1 below represents a 50mV gain in 'ON' pipe to soil potentials from the far test station to the near test station, produced as a result of the existence of the current I_{CP}.

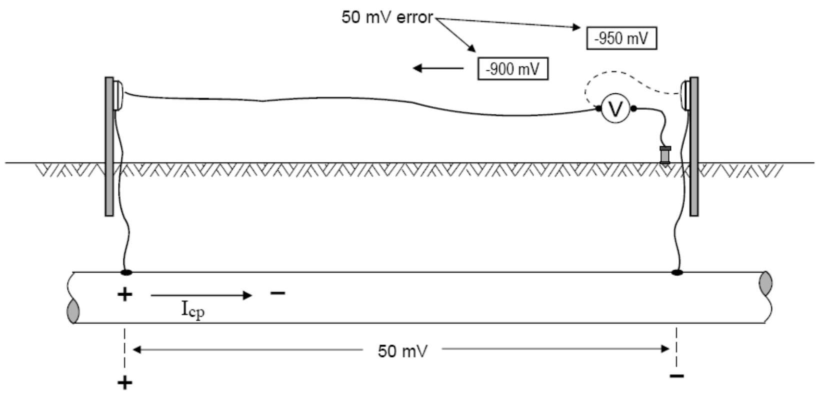


Figure 5.1: Metallic IR Drop

Due to the range volatility of the values collected in this survey, this method was not practical to apply; however, the presence of DC interference was proven via the other methods mentioned in this report.

The risks associated with HVAC interference at any point on the structure can be assessed using AC structure-to-soil potentials. In the first instance, to secure personnel from shock measured AC voltages to ground have been set by regulatory bodies to a maximum of 15VAC. Second, the propensity of AC corrosion can be assessed using the worst-case assumptions for coating holiday size and holiday interactions with surrounding soil in combination with AC corrosion guidelines provided by NACE and measured soil resistivity values. These guidelines can be simplified into thresholds presented in **Table 5**.

A secondary method of data collection was also performed in order to verify that the line was clean of external rectifier DC influence. This method specifically targets foreign rectifiers by measuring the frequency of the line and ensuring there is no 120Hz ripple in the 'OFF' cycle of rectifier interruption, confirming that there is no rectifier influence during the 'OFF' cycle.

A digital oscilloscope was utilized to collect pipeline data and post processed using a Fast Fourier analysis to determine that there was no 120Hz signal during the "OFF" cycle. This data can be viewed in Appendix 2. The data for the two (2) frequency graphs plotted was collected at two (2) locations. The first location was at the Kenogami station and the second was nearby Amikougami creek. As seen on the chart for Kenogami station, a minor and negligible 120Hz frequency remained present on the line with all known rectifiers in the OFF position. Further testing is required to determine the unknown source which remains to be interrupted; however, the minor size of the peak enables it to be deemed negligible at this stage. Therefore, rectifier and outside DC influences on the pipeline were ruled out.

Furthermore, it is found that there is a consistent 60hz component within the signals found on the piping. This 60hz can be found in most piping systems and areas as these signals will be induced from all hydro lines and powered systems that surround or cross the piping. As well, a component of the harmonic frequencies associated with this 60hz signal can often be found to be present, with the odd harmonics found to be the most prevalent in such electrical systems. Hence a large component of 180hz (3rd harmonic) will often be present when investigating piping systems. This has the added effect of making the identification of any unknown three-phase protection systems present on the lines additionally difficult if not functionally impossible. Please note that the y-axis of the chart shown in Appendix 2-4 has a complex voltage unit, and its purpose is to depict the magnitude of various frequencies only.

Finally, from Table 14, AC voltages across the test locations were found to be smaller than 90% of the measured soil resistivities. This indicates there is little to no risk of corrosion due to AC interference at defect locations.

APPENDIX 1

IMAGES

FIGURE 1: THE KIRKLAND LAKE LINE – SURVEY DATA POINTS PATH SHOWN

FIGURE 2: VERY ROCKY TERRAIN IN SOME AREAS

FIGURE 3: SOIL RESISTIVITY TEST IN PROGRESS

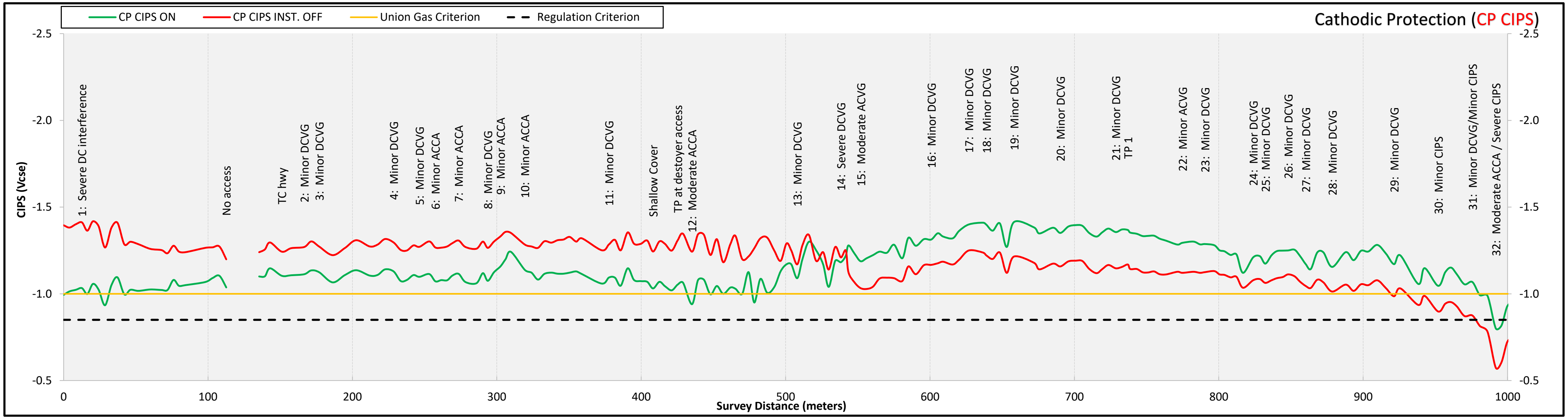
FIGURE 4: EXPOSED PIPE UNDER ROCK BOULDERS

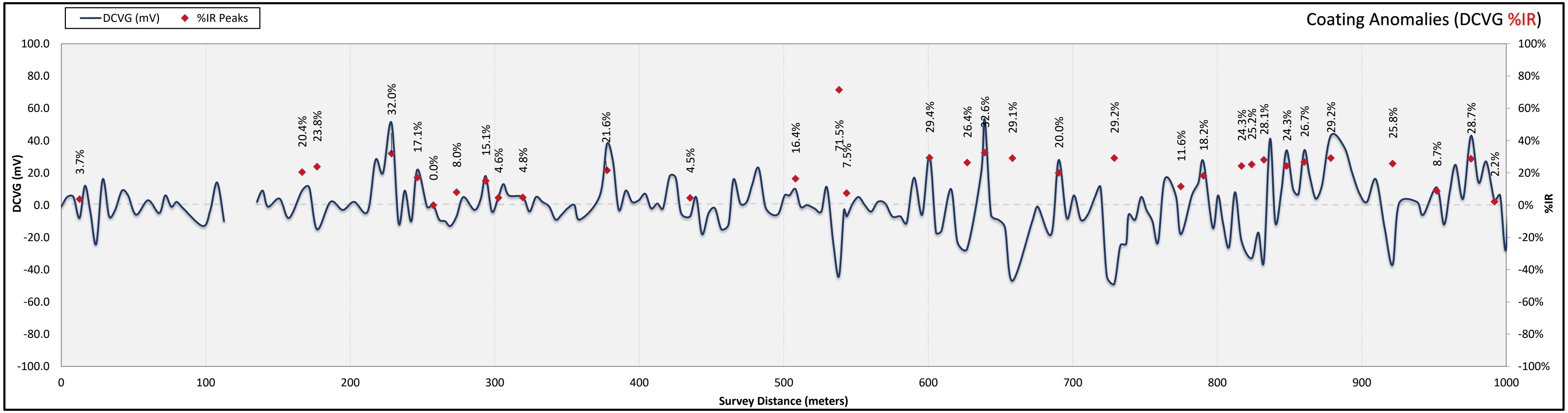
APPENDIX 2

ABOVE GROUND INSPECTION CHARTS

AEGION® Stronger. Safer. Infrastructure.® corrpro®

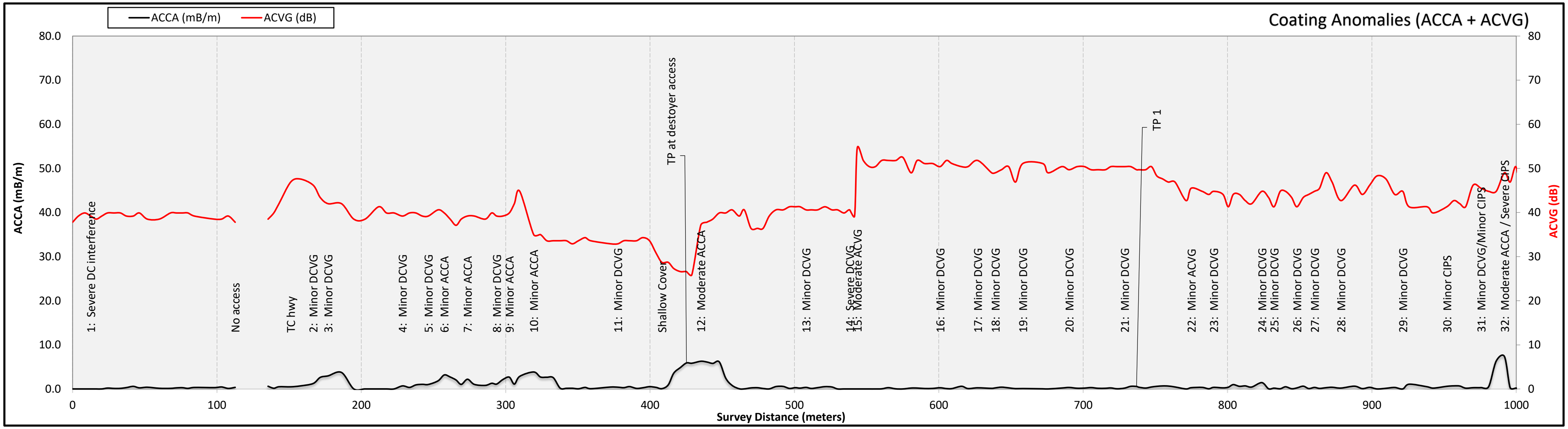
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

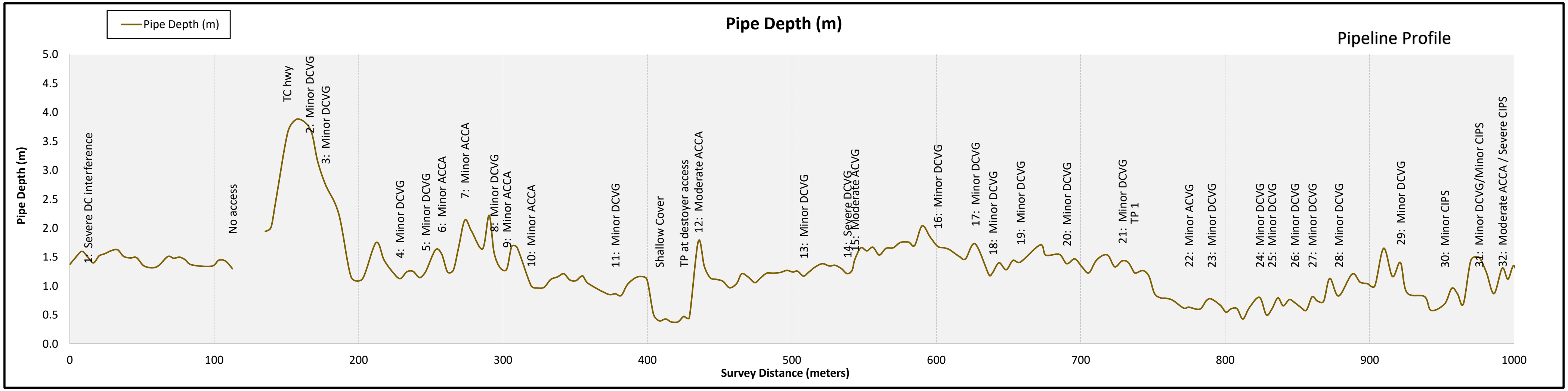




AEGION®
Stronger. Safer. Infrastructure.®
corrpro®

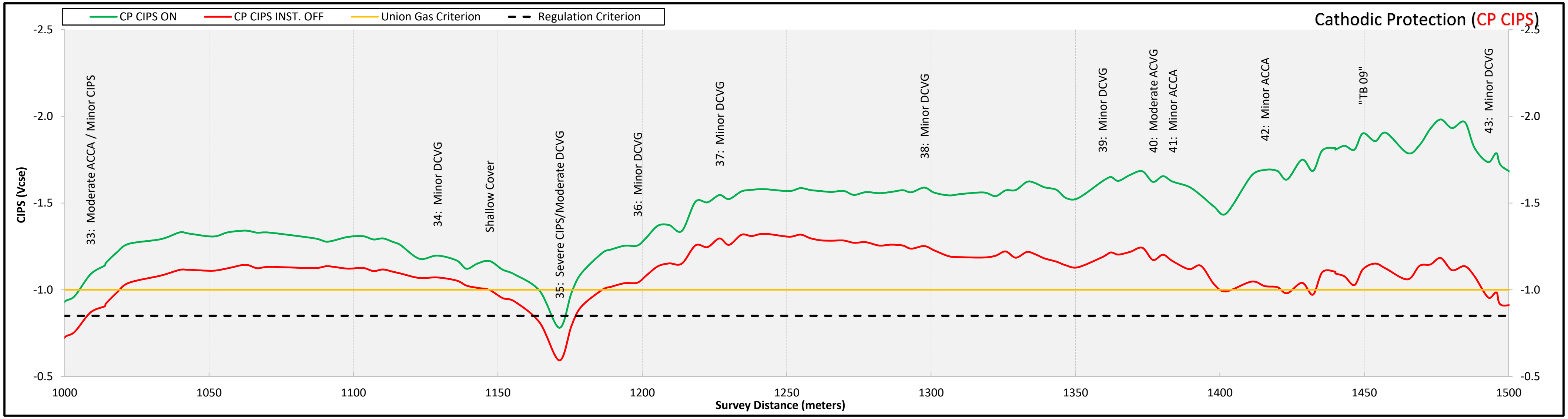
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

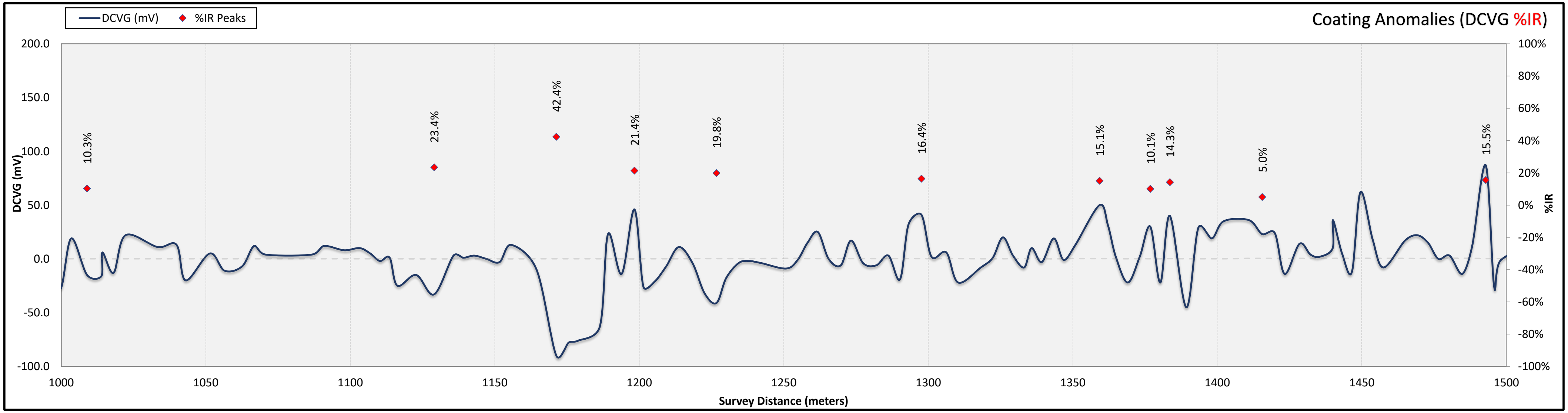




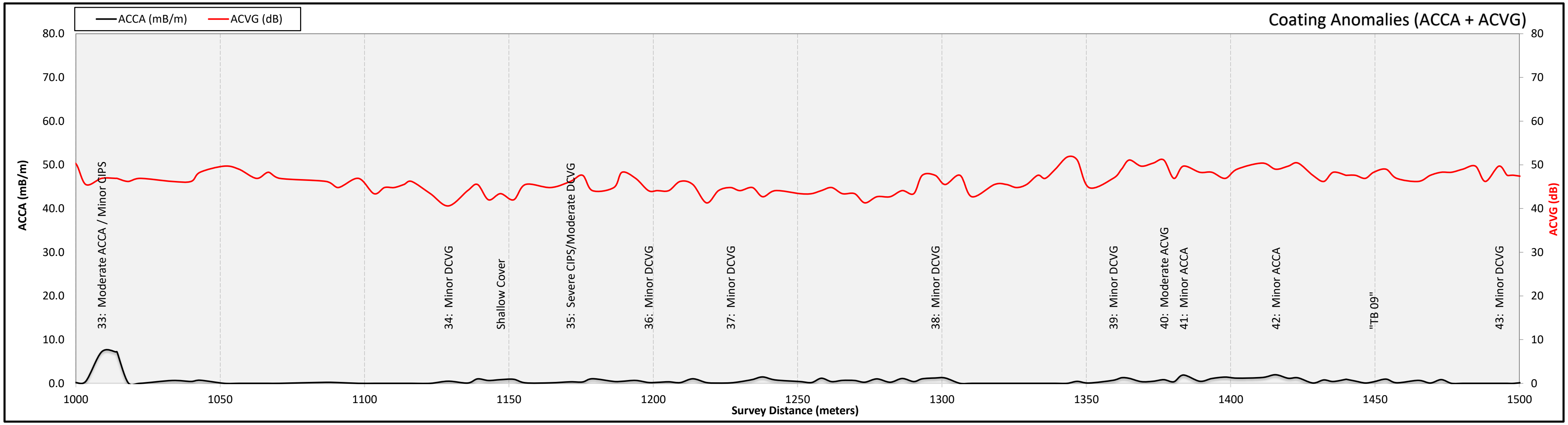
AEGION
Stronger. Safer. Infrastructure.
corrpro

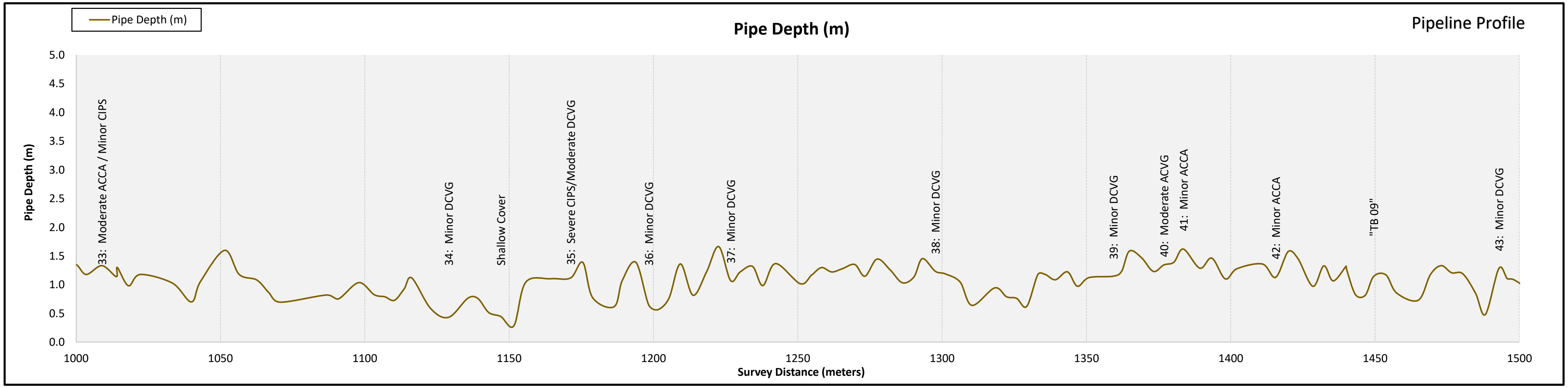
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700





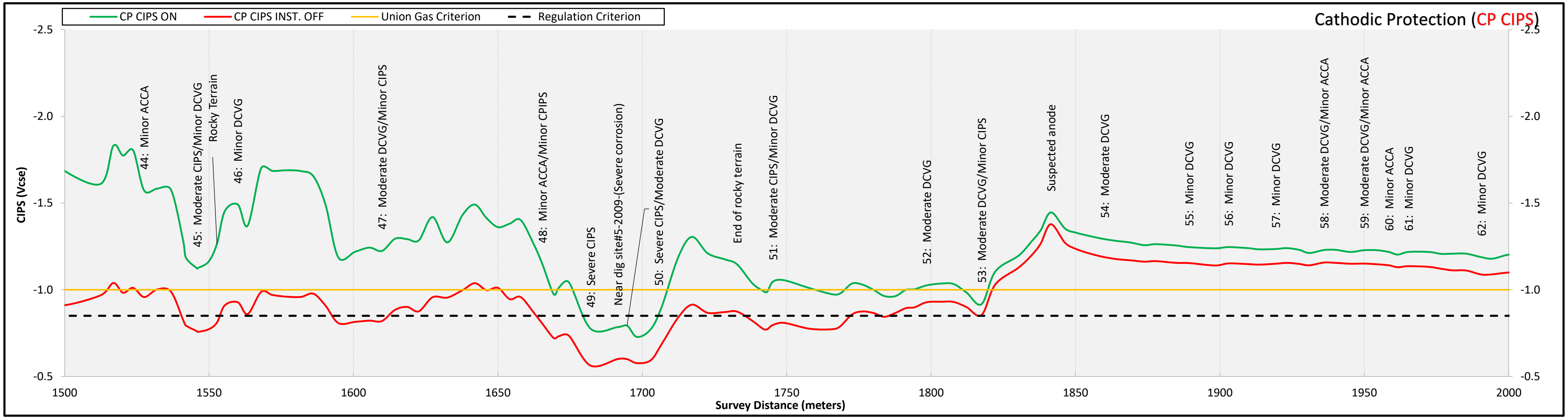
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

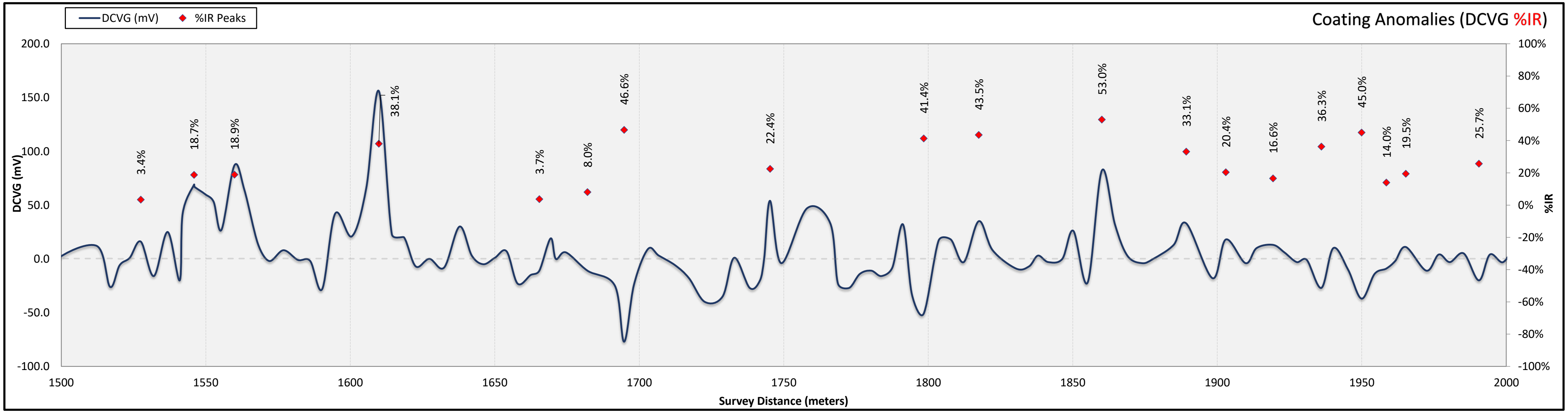




AEGION
Stronger. Safer. Infrastructure.
corrpro

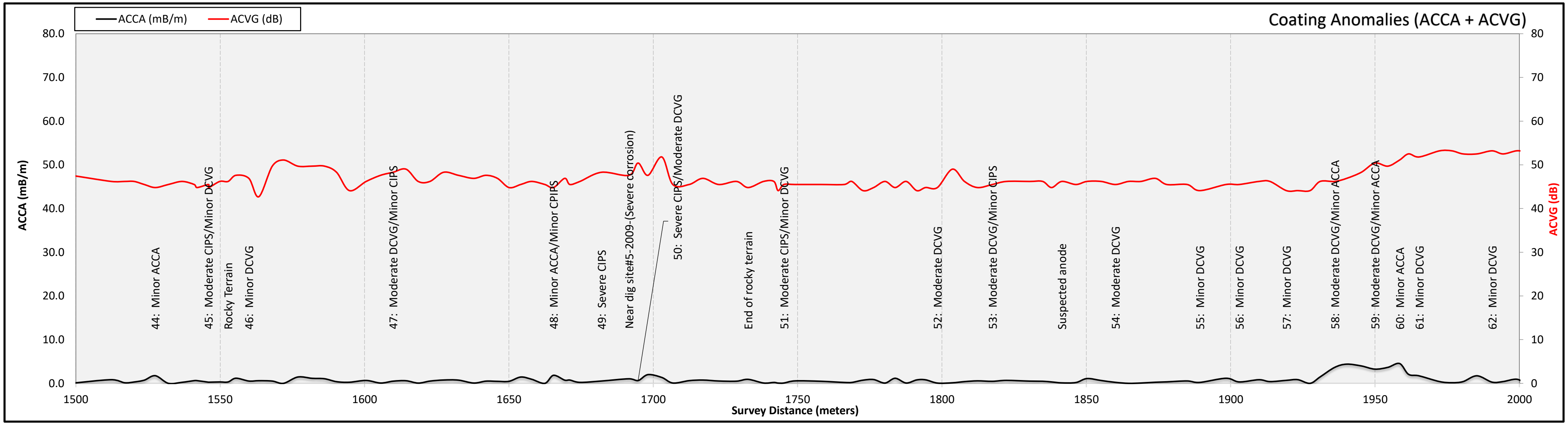
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

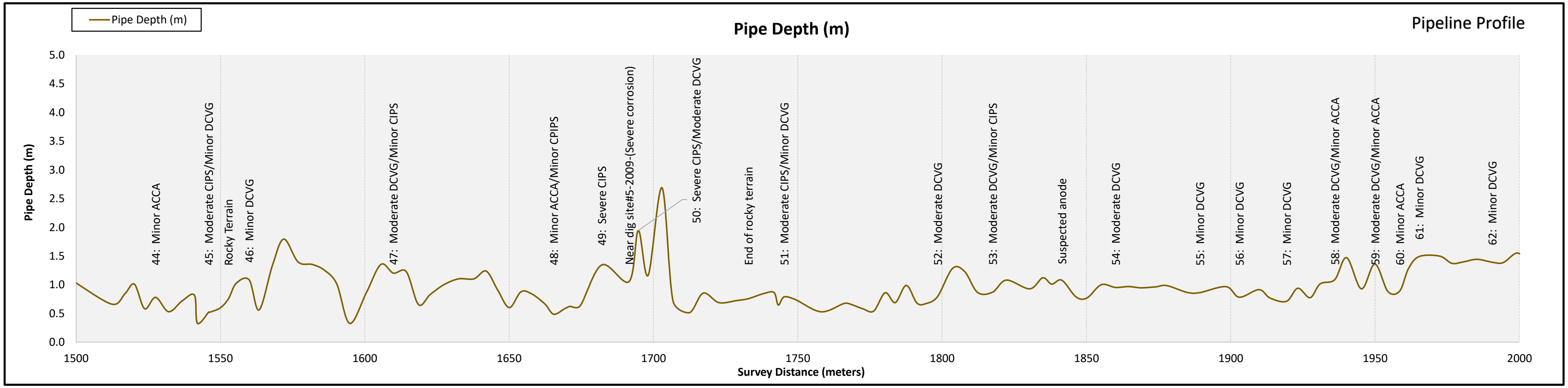




AEGION
Stronger. Safer. Infrastructure.
corrpro

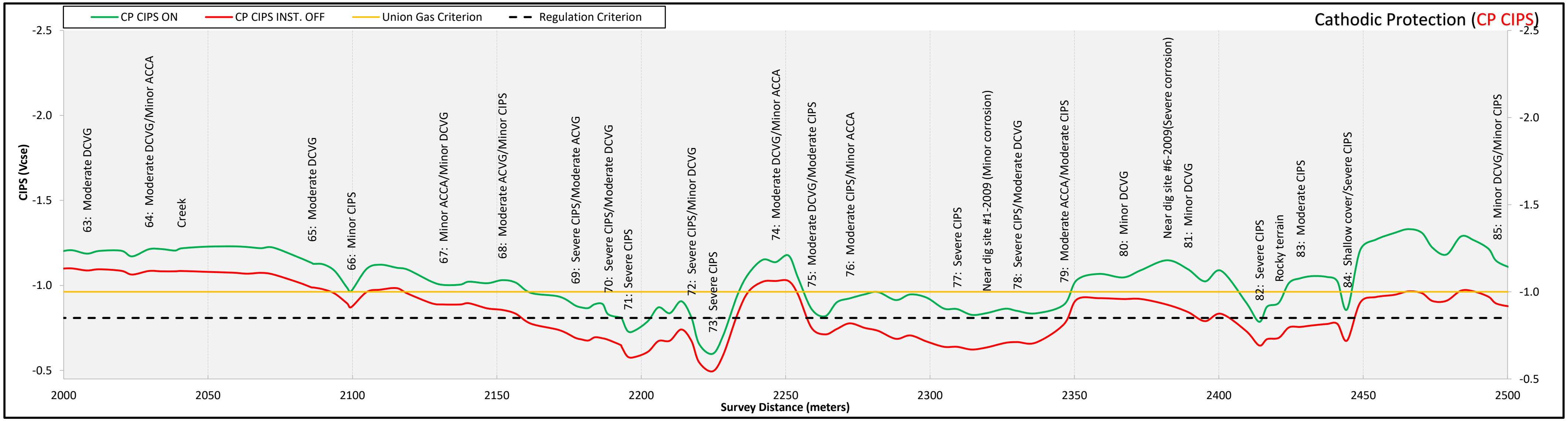
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

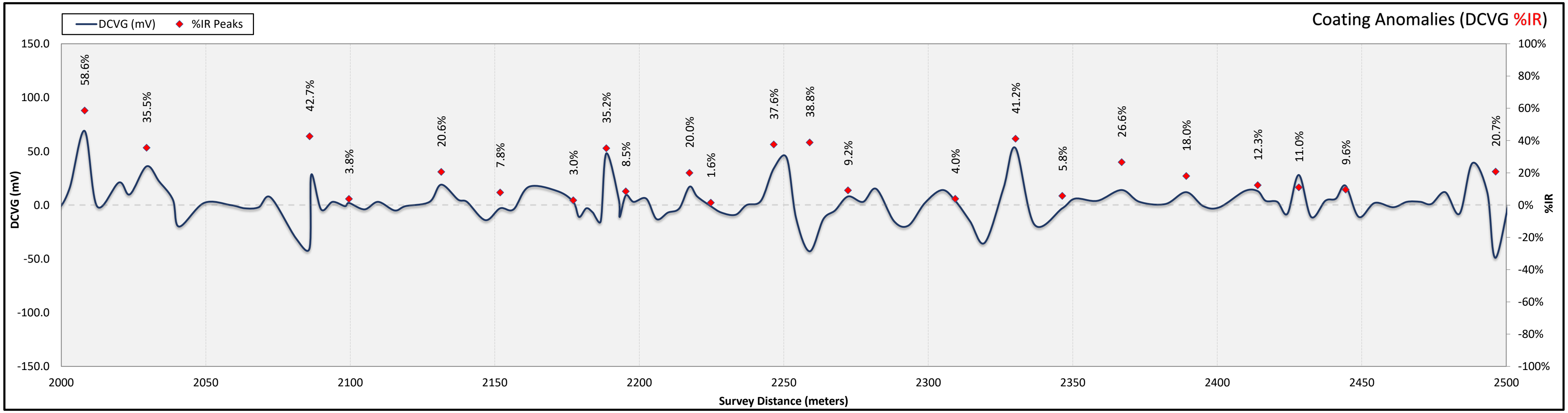




AEGION
Stronger. Safer. Infrastructure.
corrpro

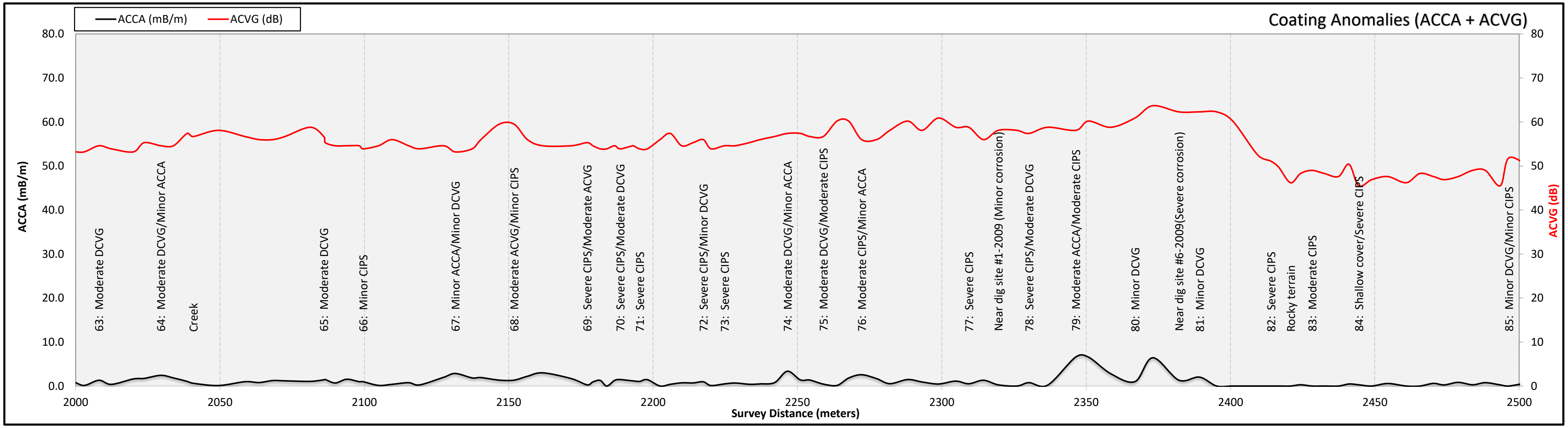
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

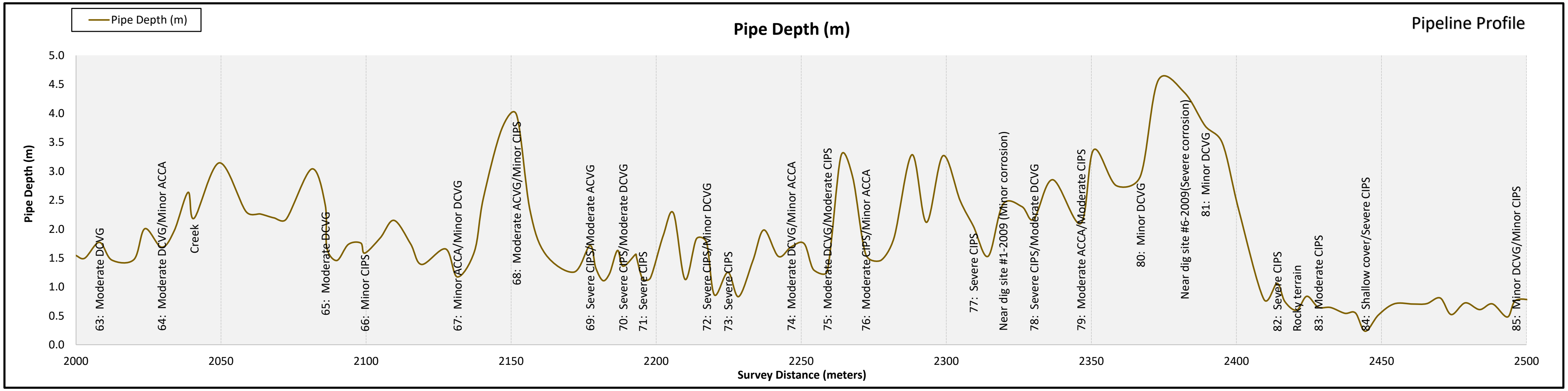




AEGION Stronger. Safer. Infrastructure. corrpro

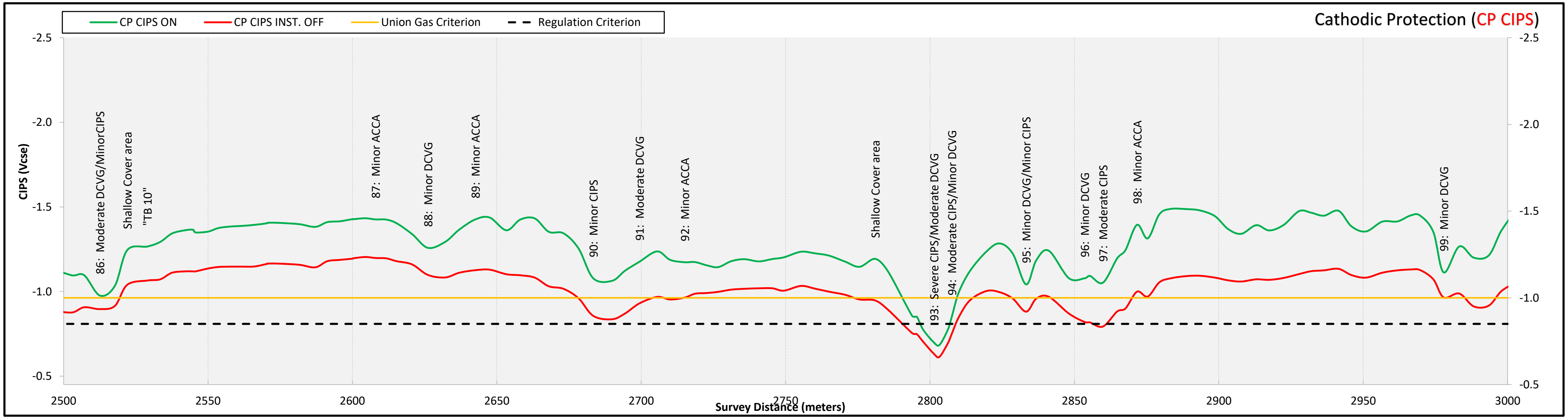
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

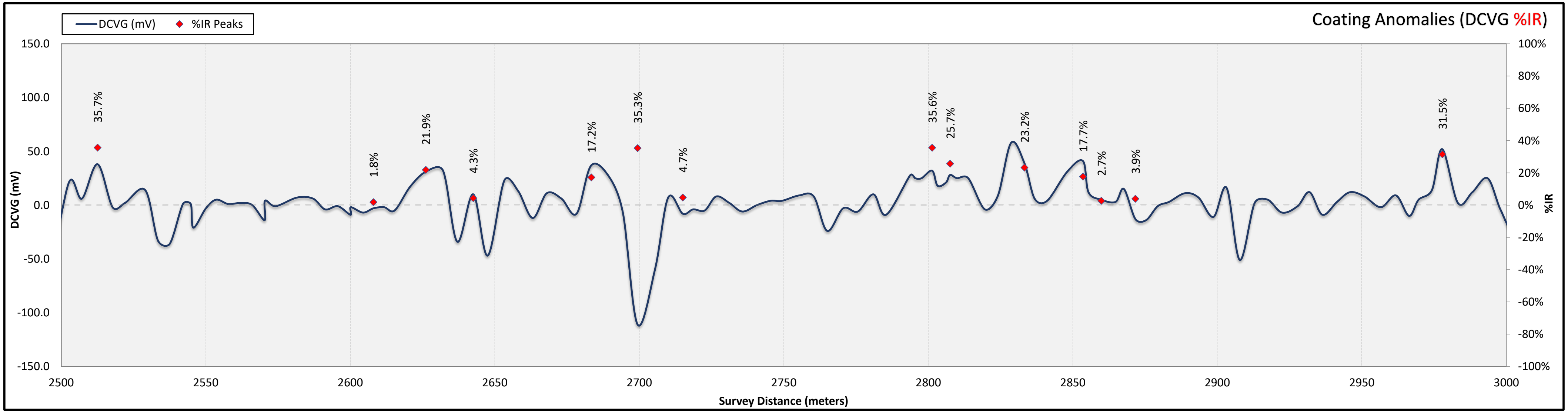




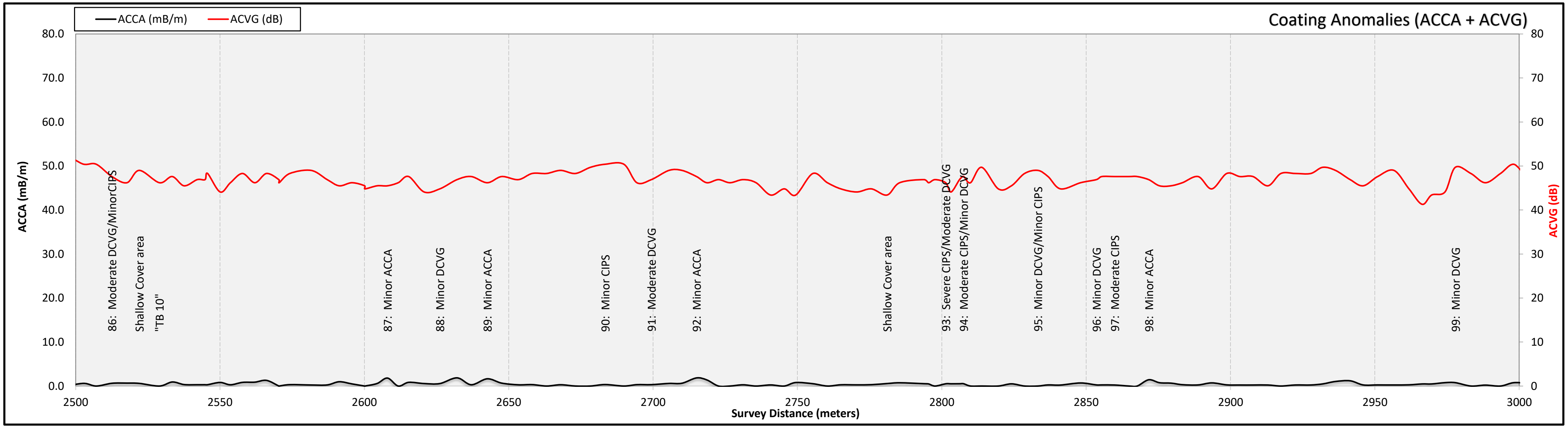
AEGION® Stronger. Safer. Infrastructure.® corrpro®

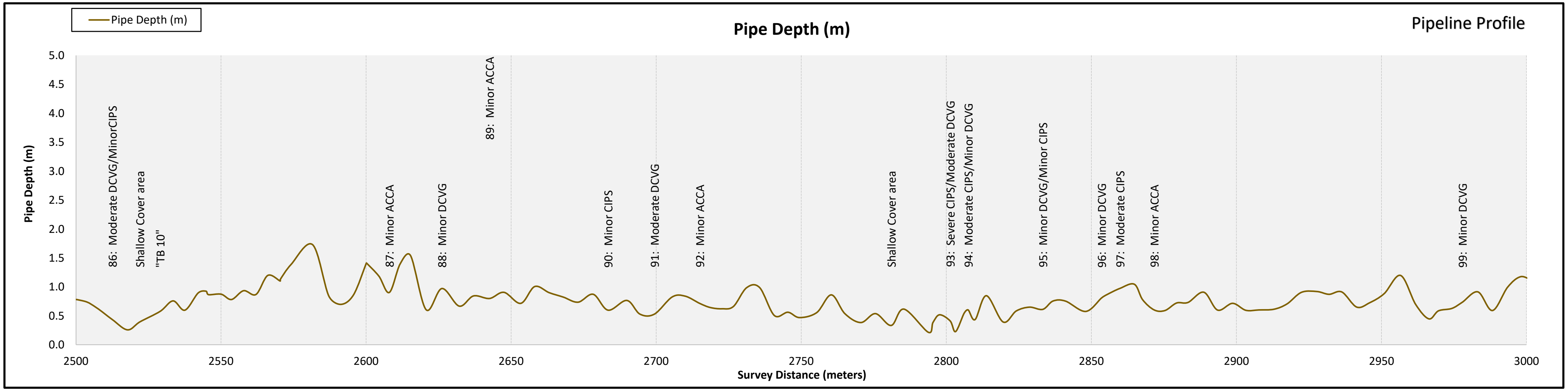
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700





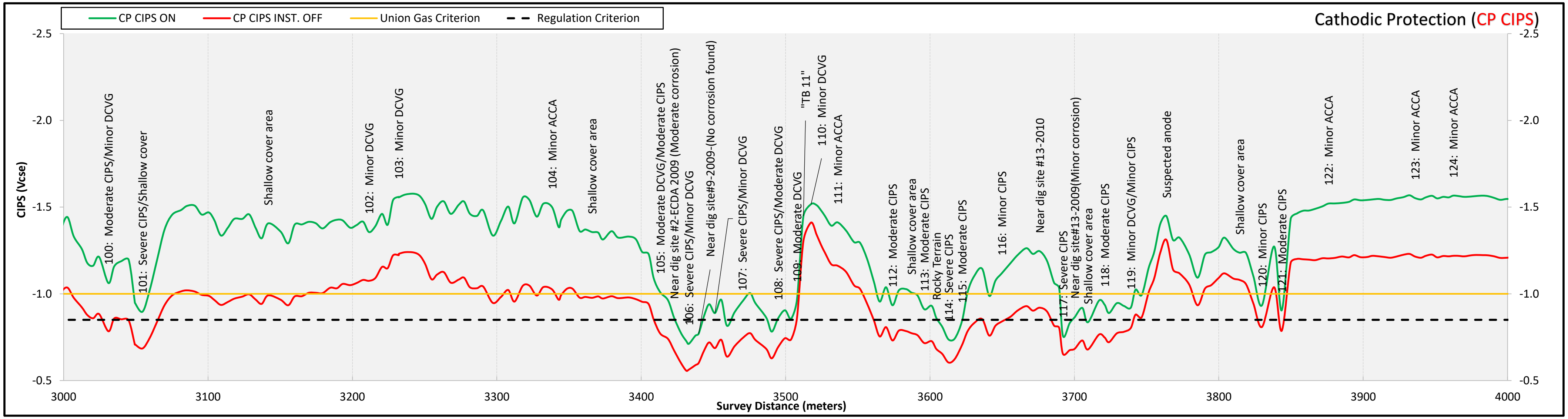
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

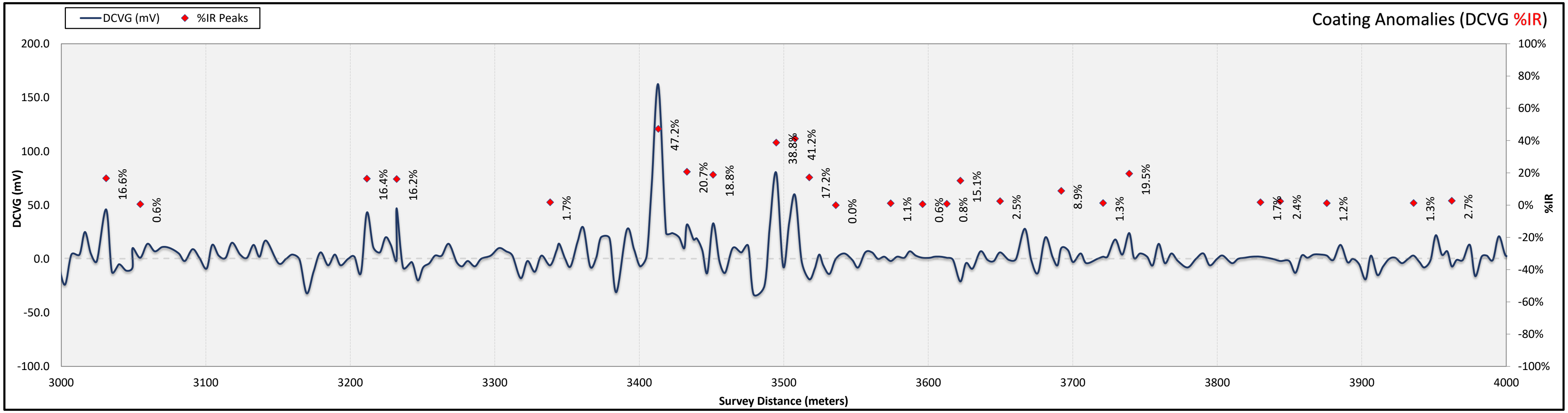




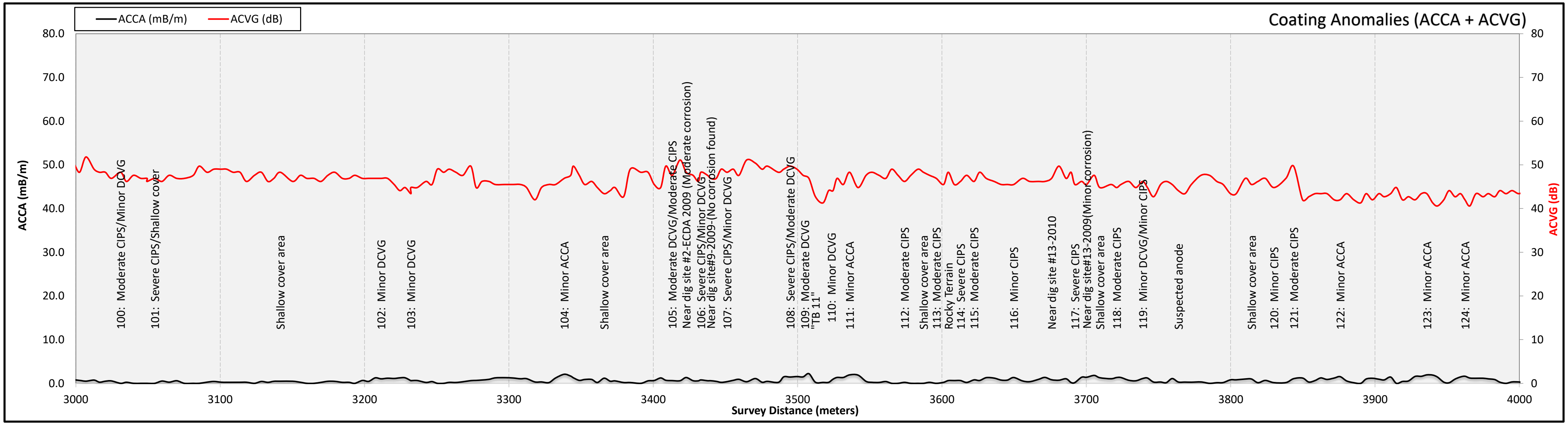
AEGION® Stronger. Safer. Infrastructure.® corrpro®

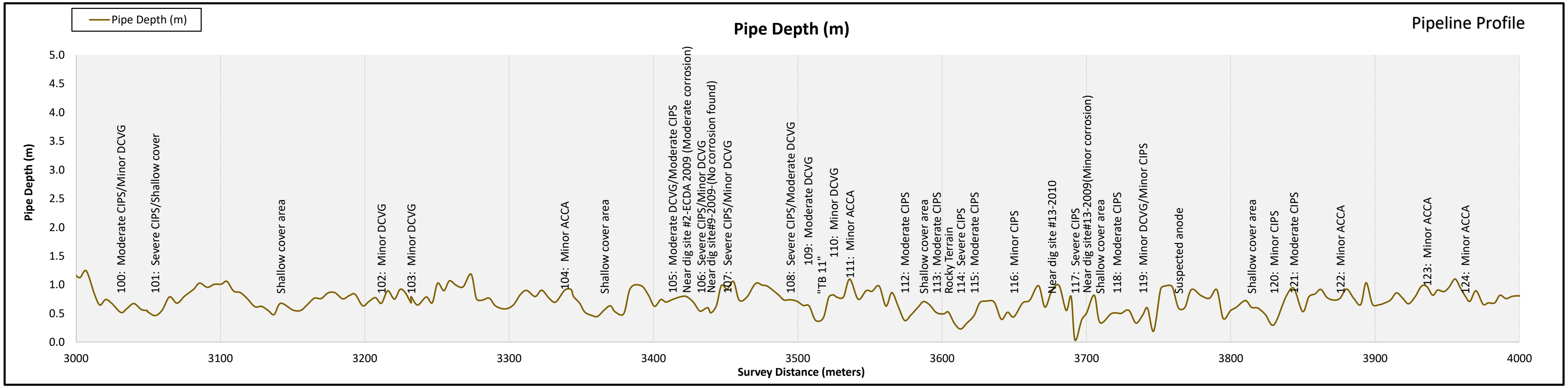
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700





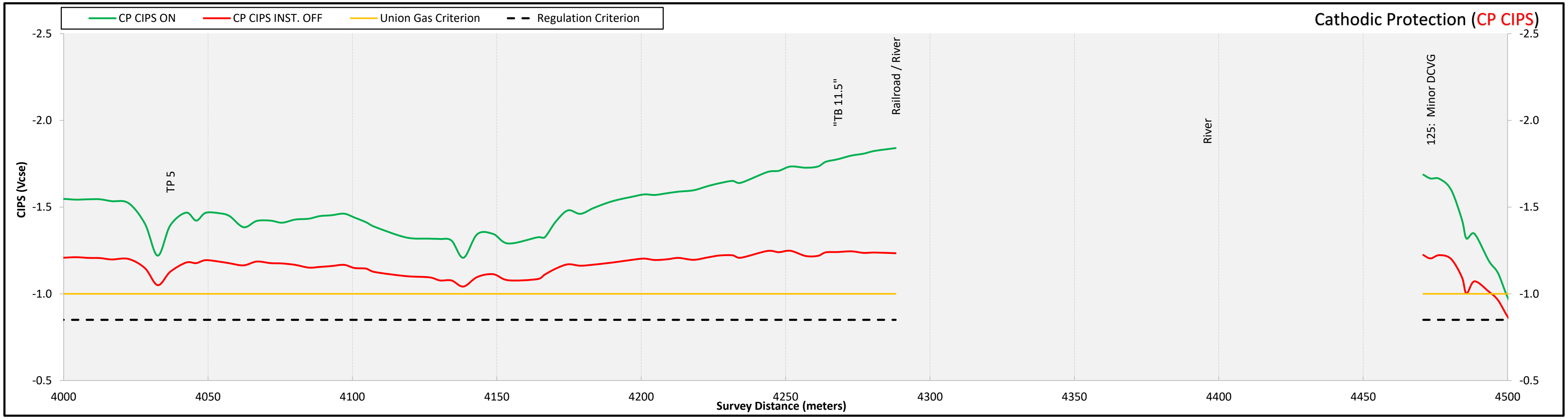
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

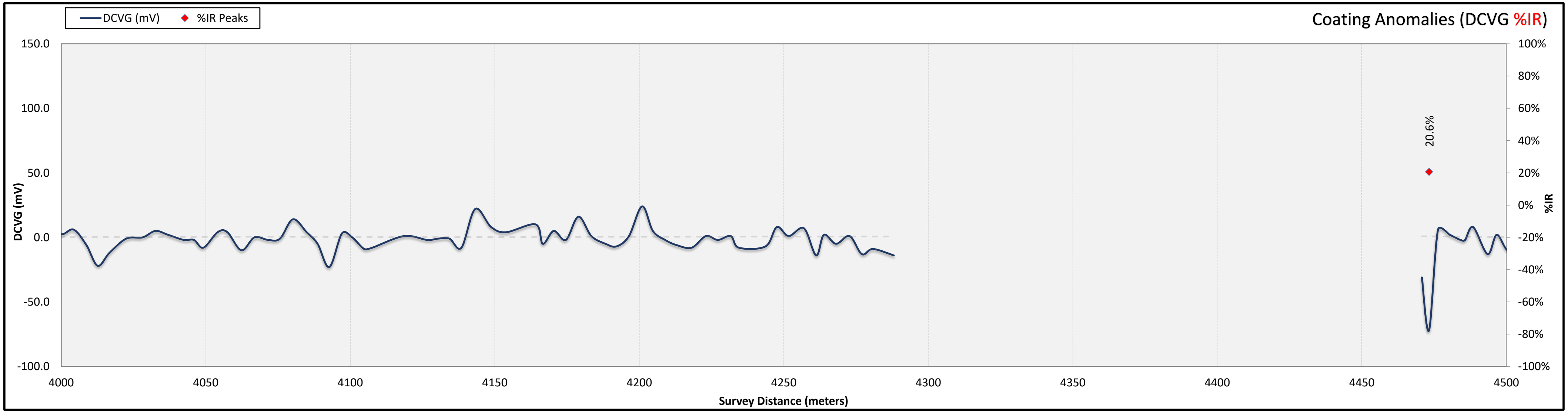




AEGION®
Stronger. Safer. Infrastructure.®
corrpro®

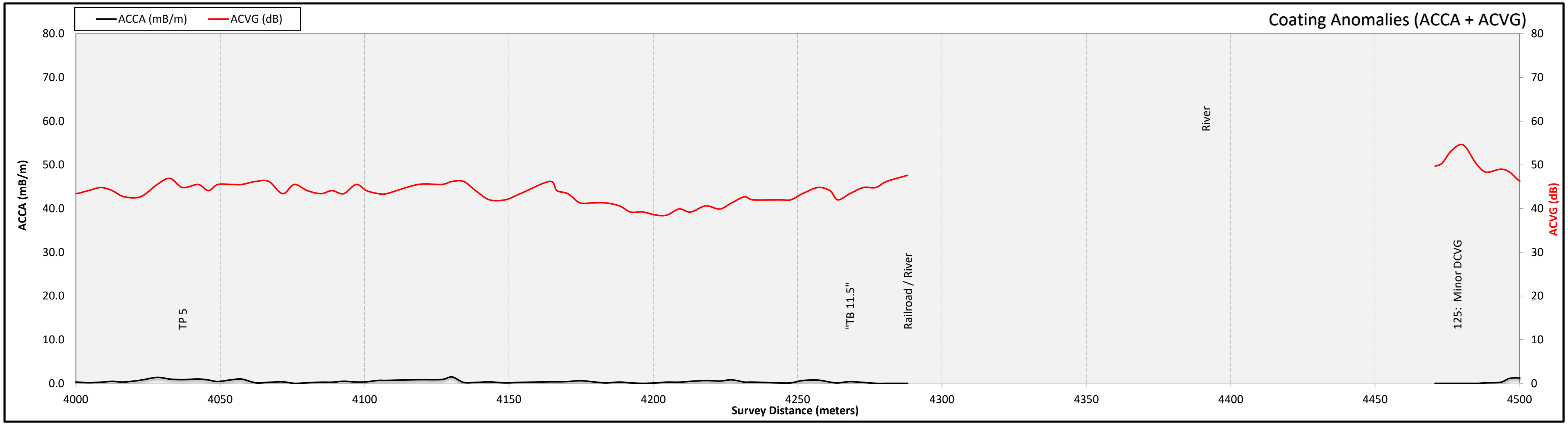
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

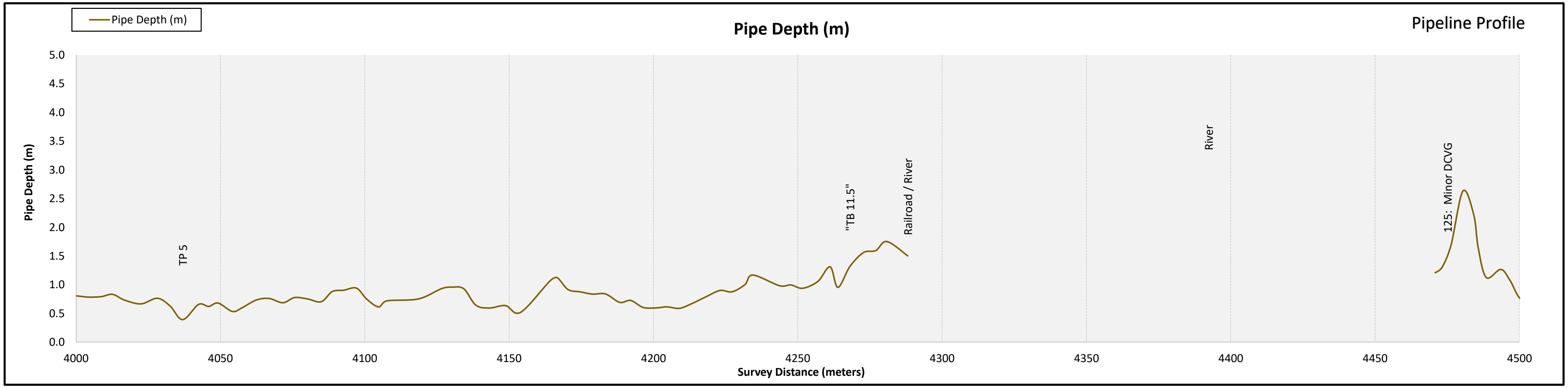




AEGION
Stronger. Safer. Infrastructure.
corrpro

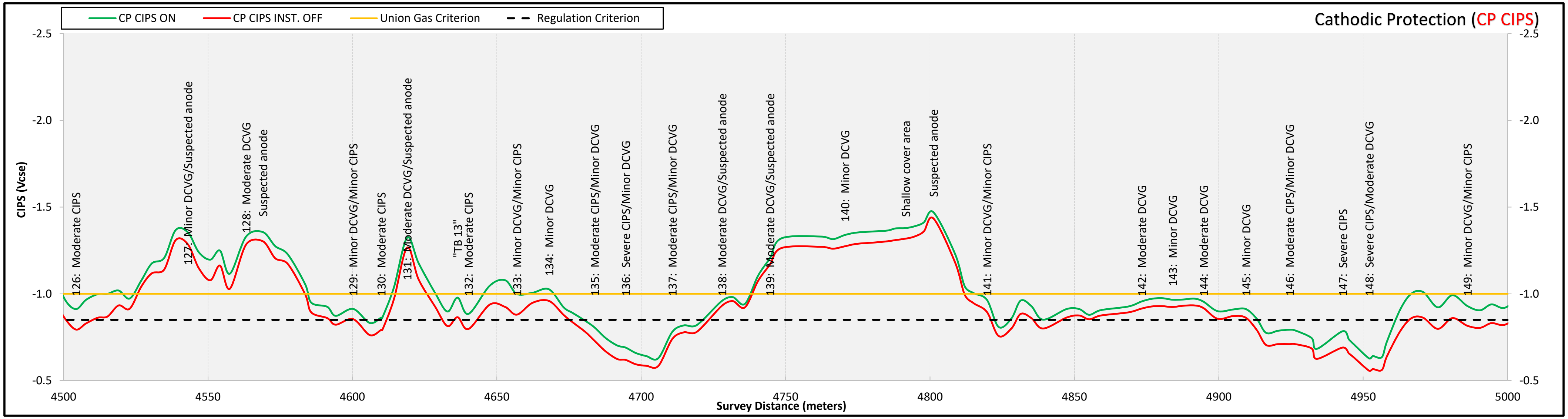
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

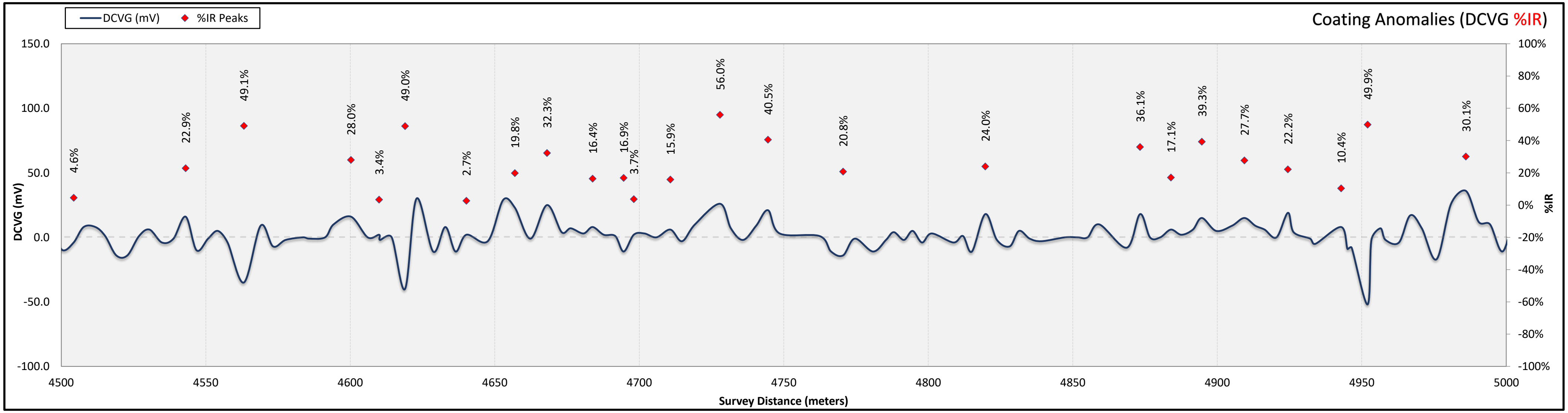




AEGION
Stronger. Safer. Infrastructure.
corrpro

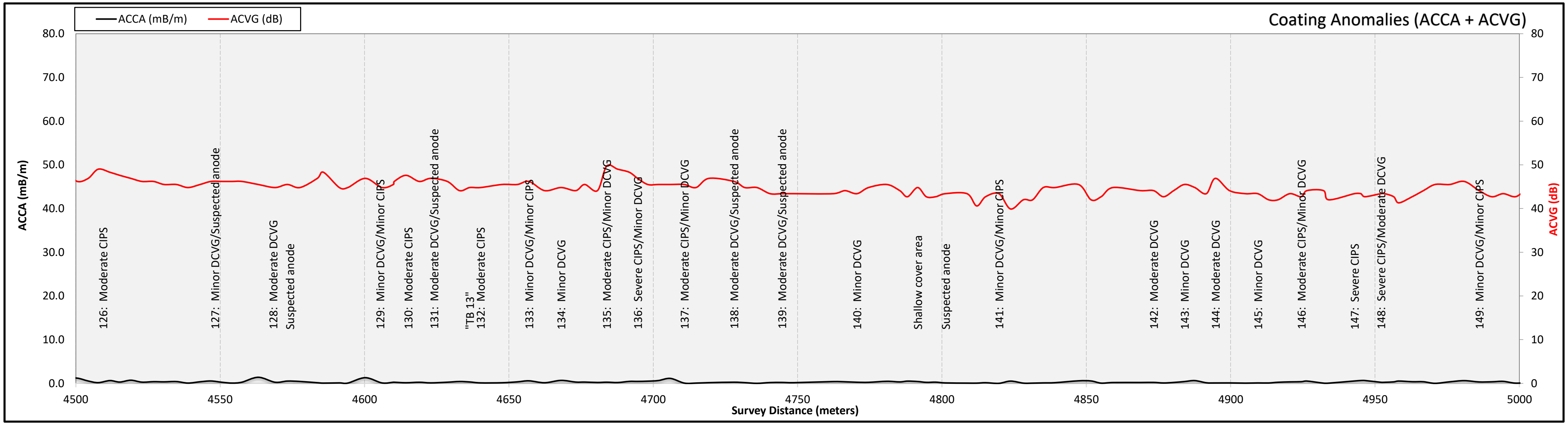
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

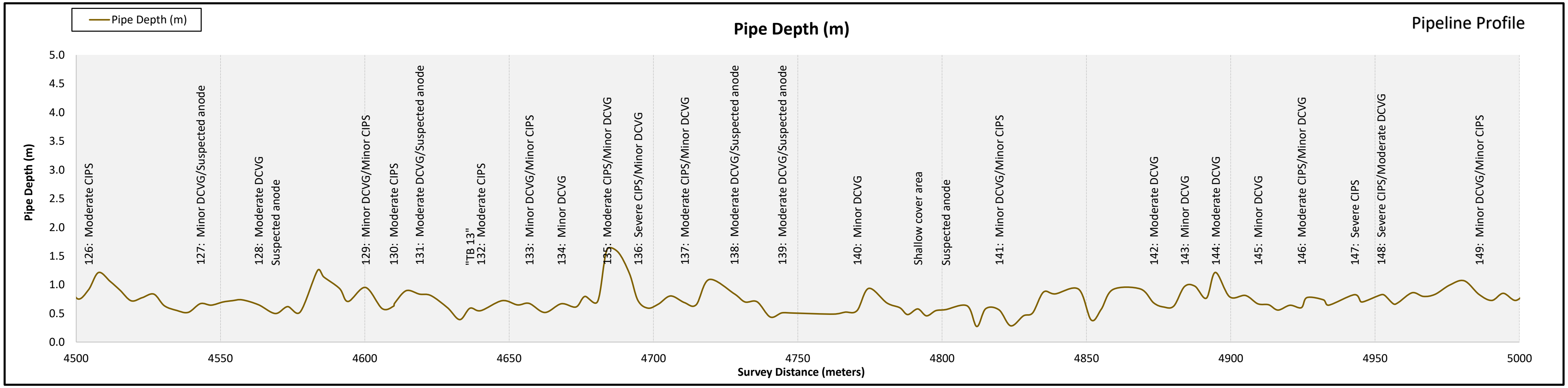




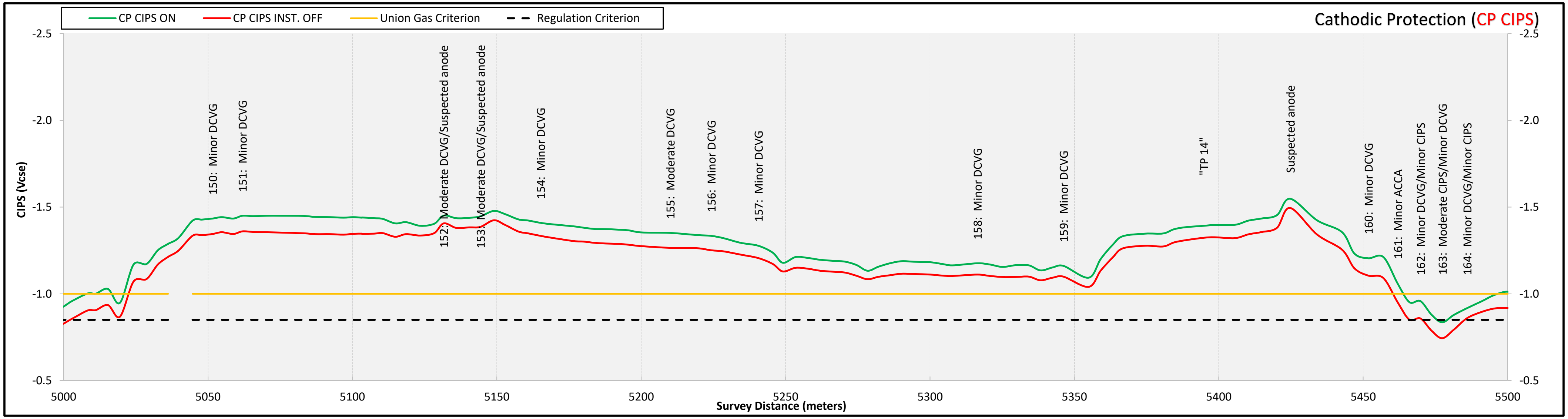
AEGION
Stronger. Safer. Infrastructure.
corrpro

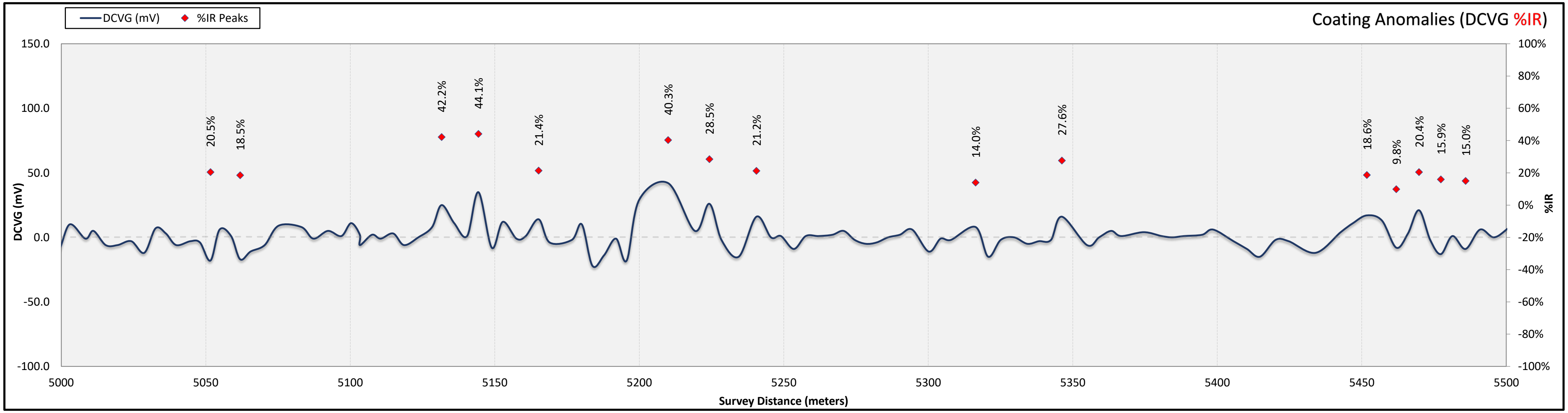
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700





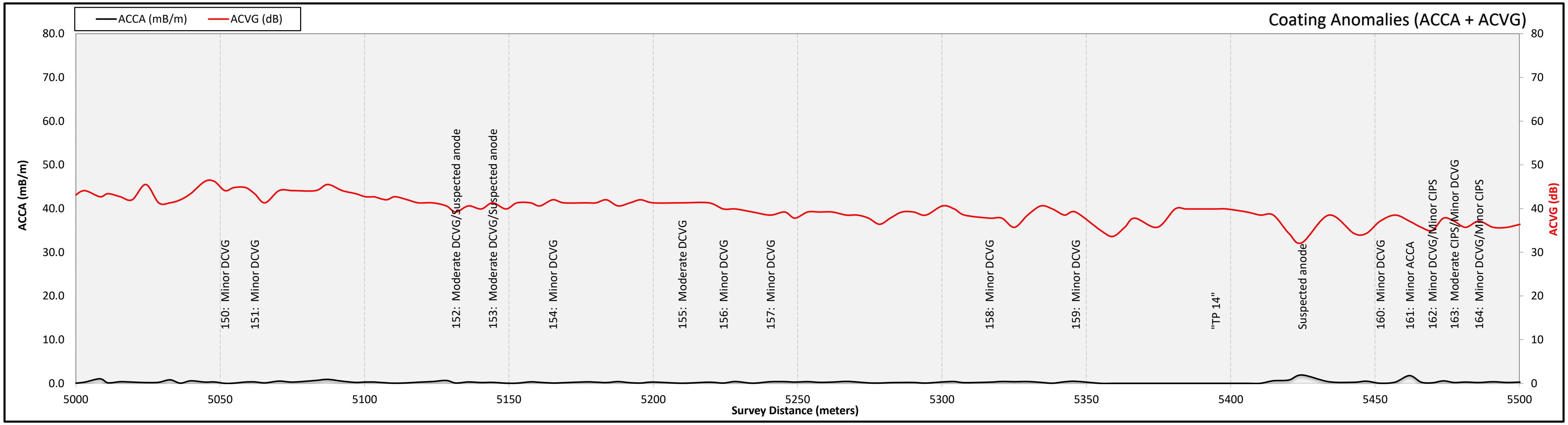
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

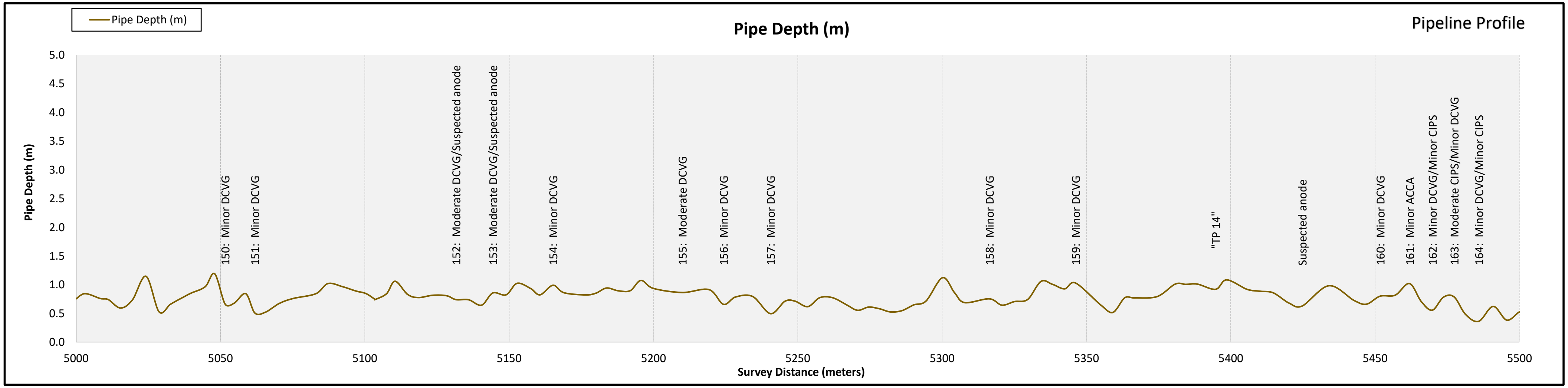




AEGION
Stronger. Safer. Infrastructure.
corrpro

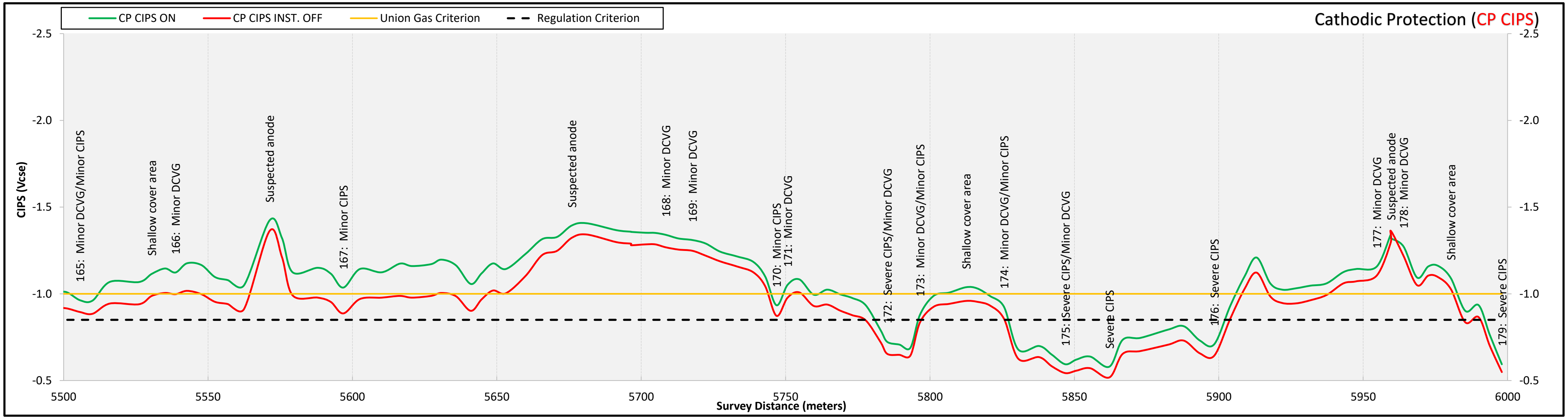
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

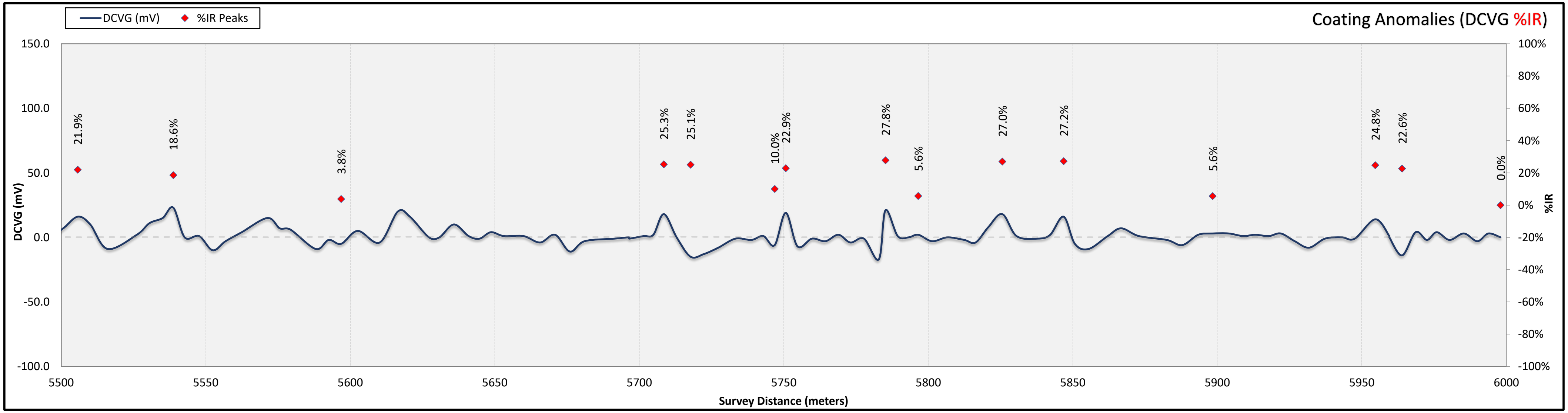




AEGION Stronger. Safer. Infrastructure. corrpro

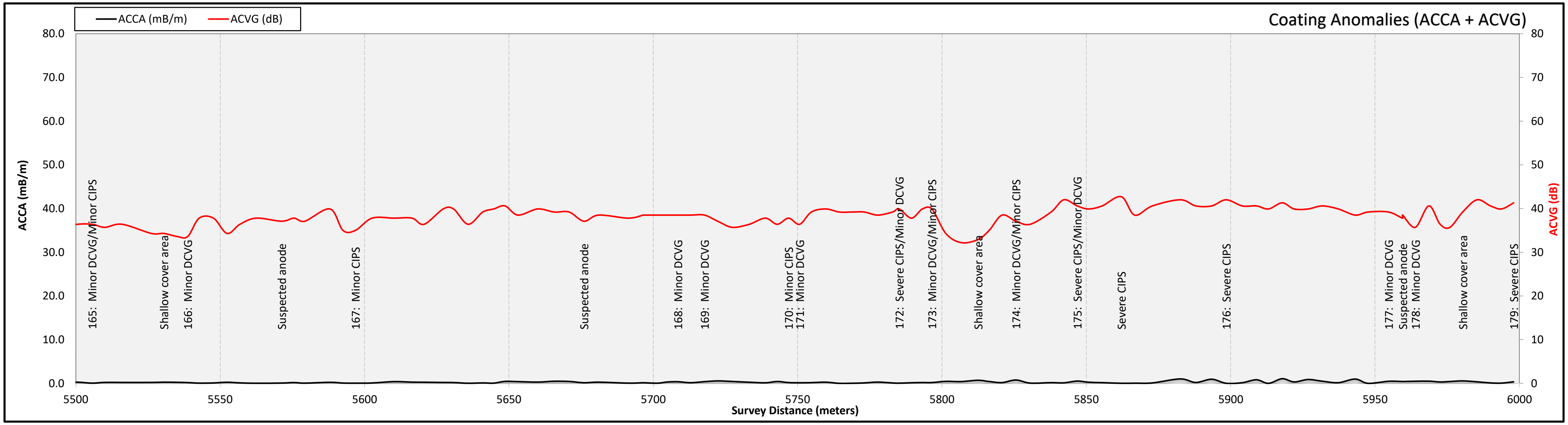
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

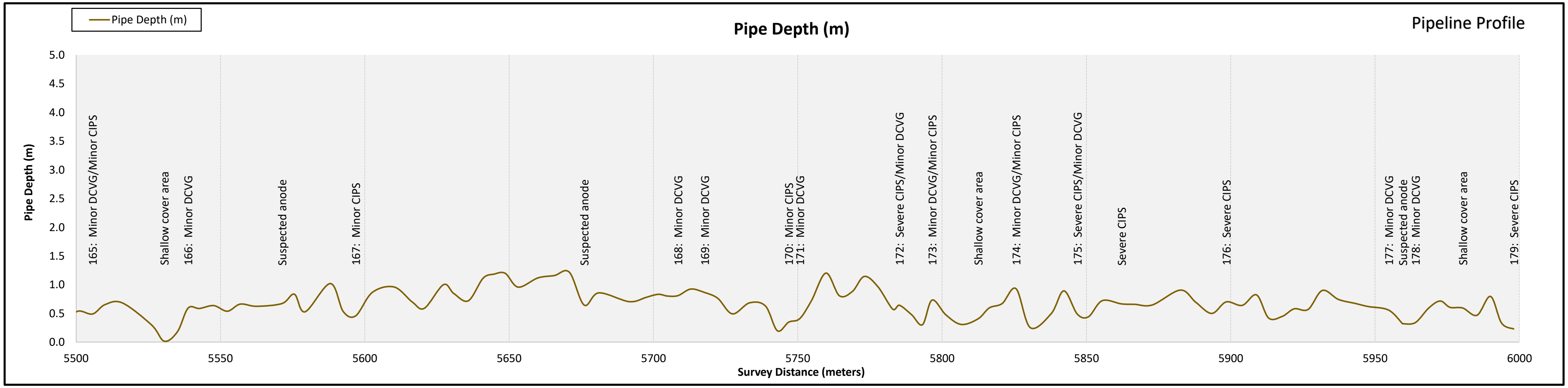




AEGION
Stronger. Safer. Infrastructure.
corrpro

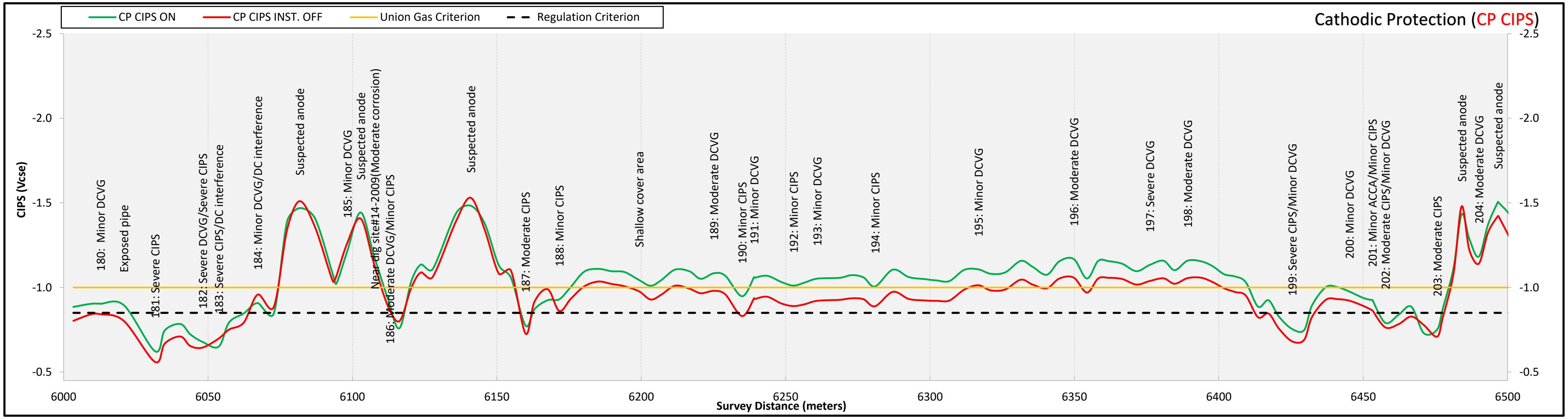
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

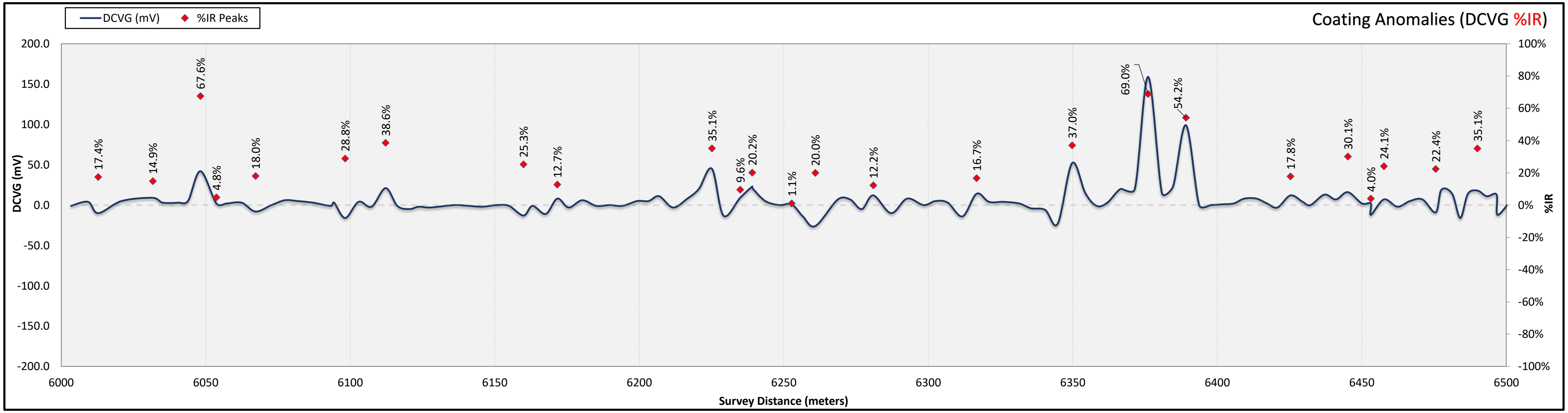




AEGION® Stronger. Safer. Infrastructure.® corrpro®

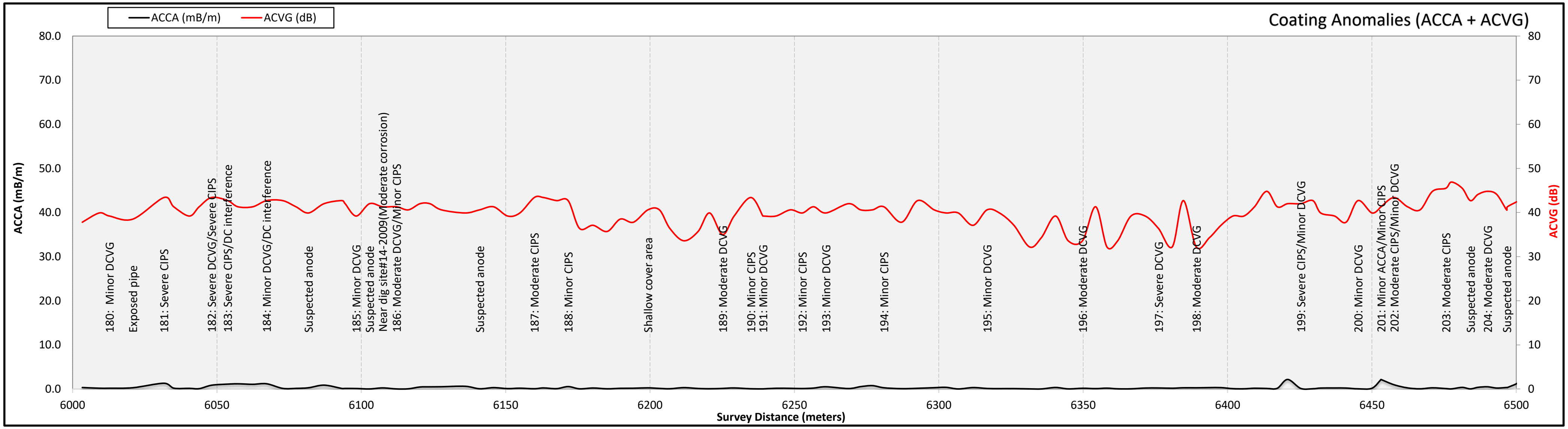
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

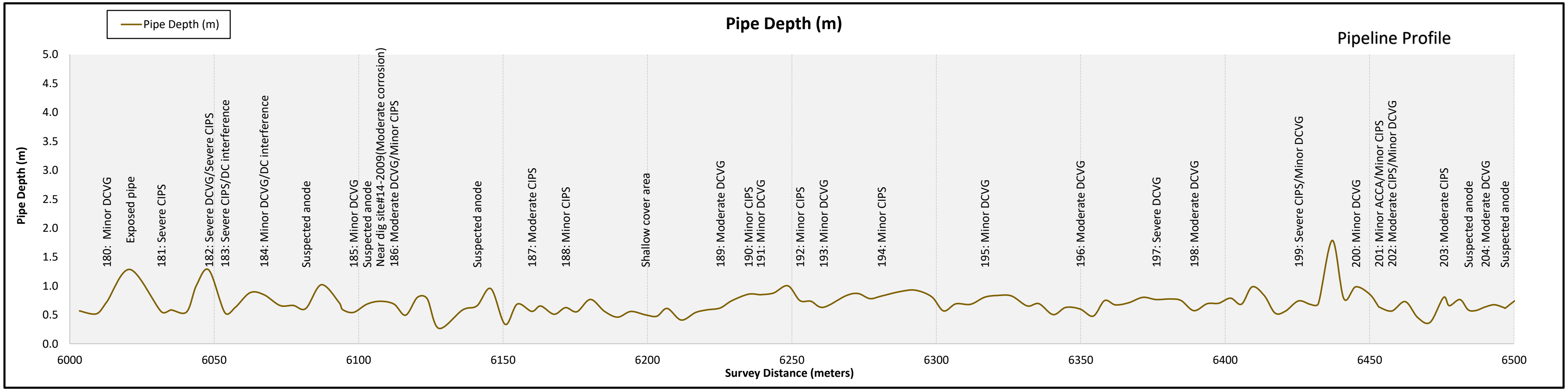




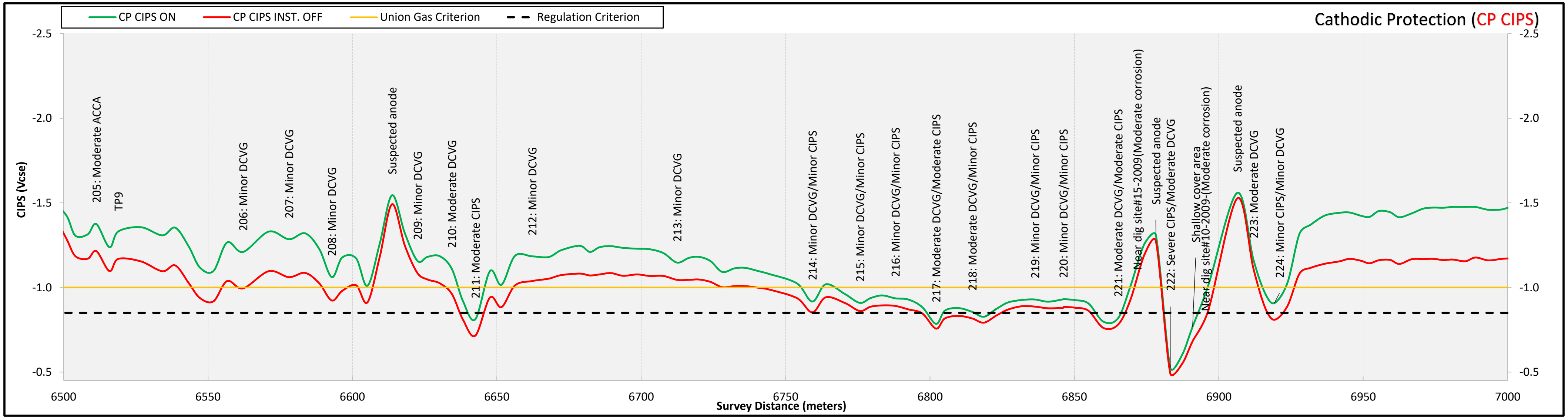
AEGION
Stronger. Safer. Infrastructure.
corrpro

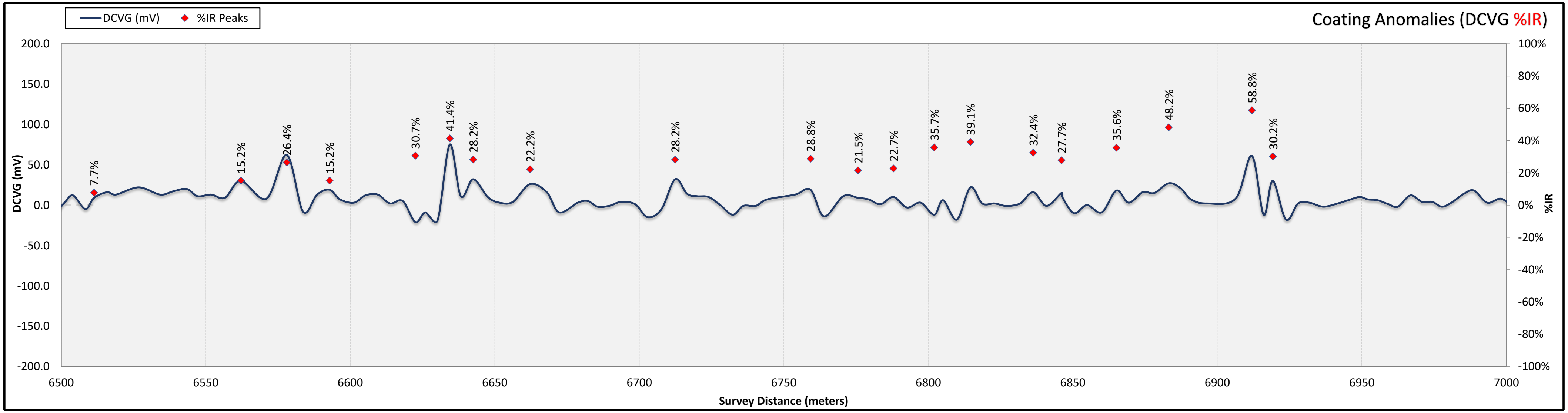
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700





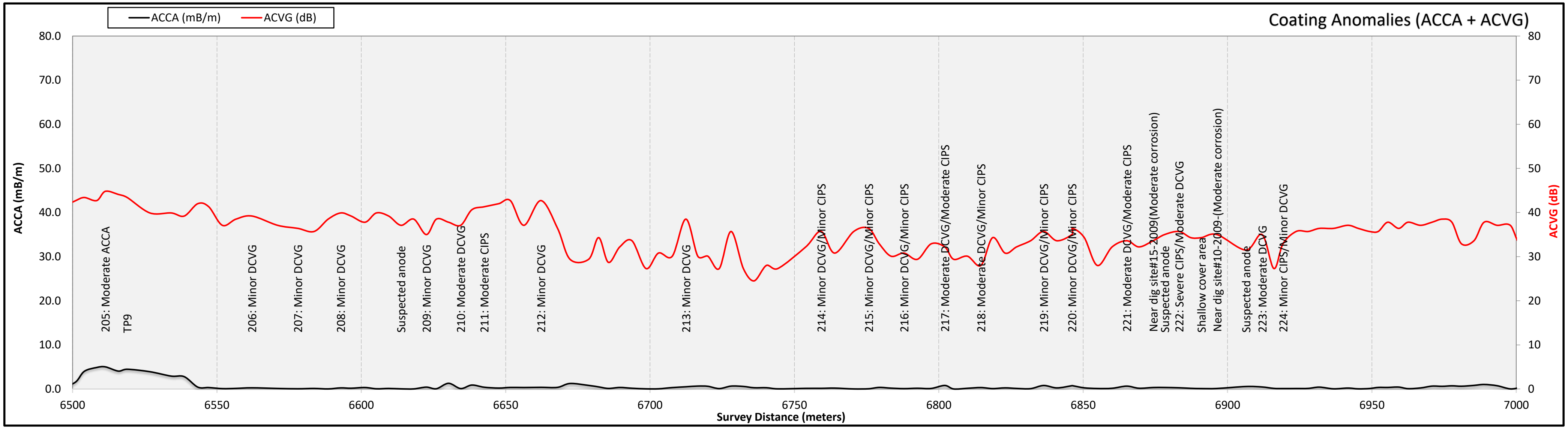
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

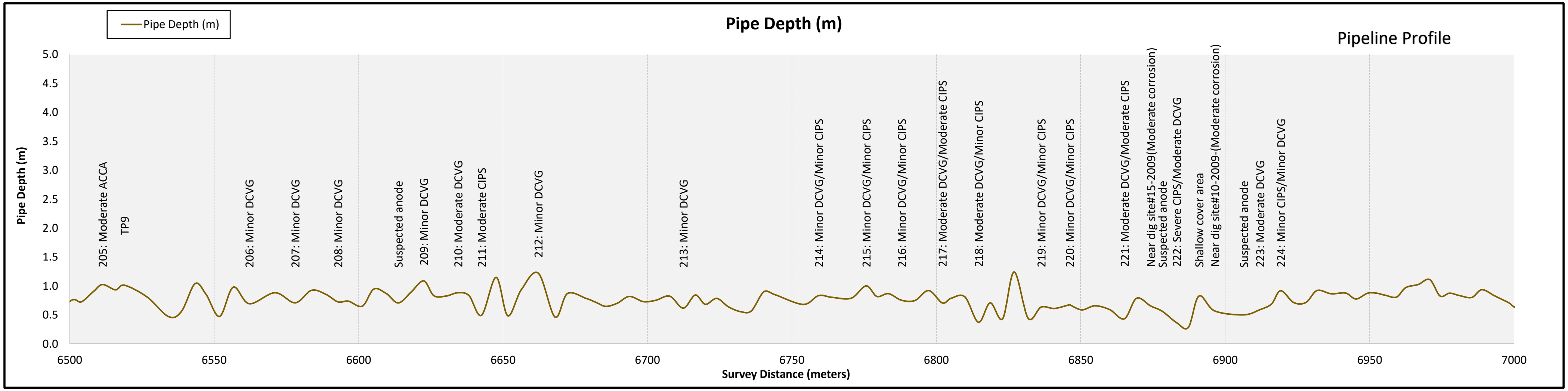




AEGION
Stronger. Safer. Infrastructure.
corrpro

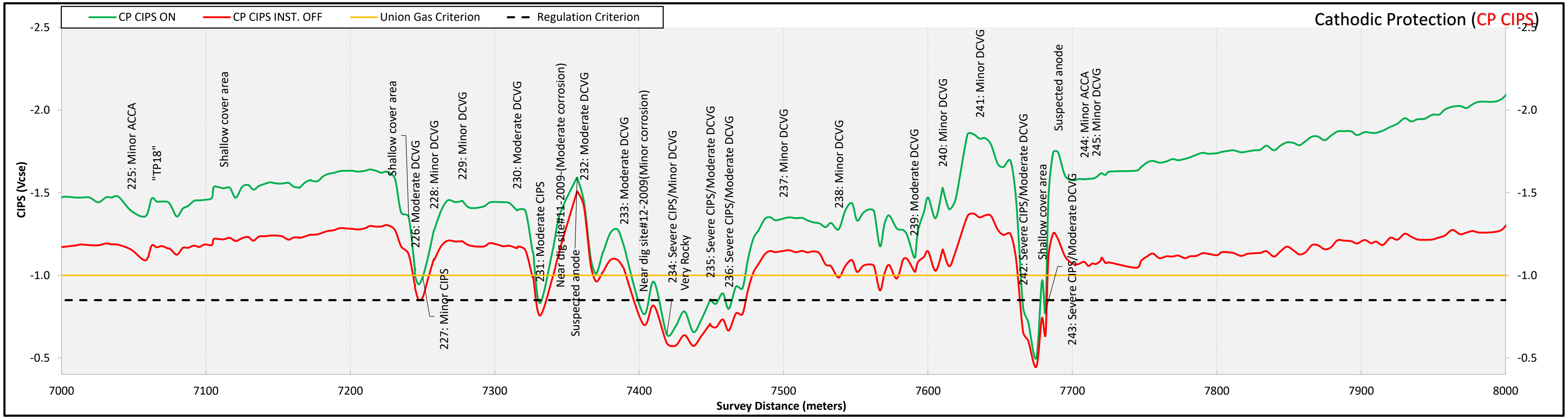
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

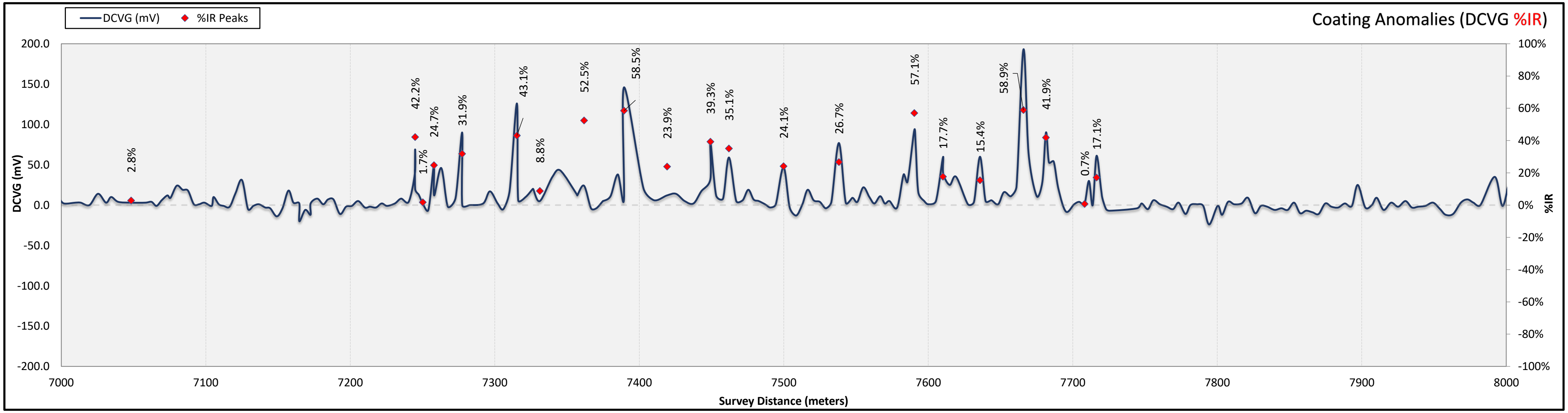




AEGION Stronger. Safer. Infrastructure. corrpro

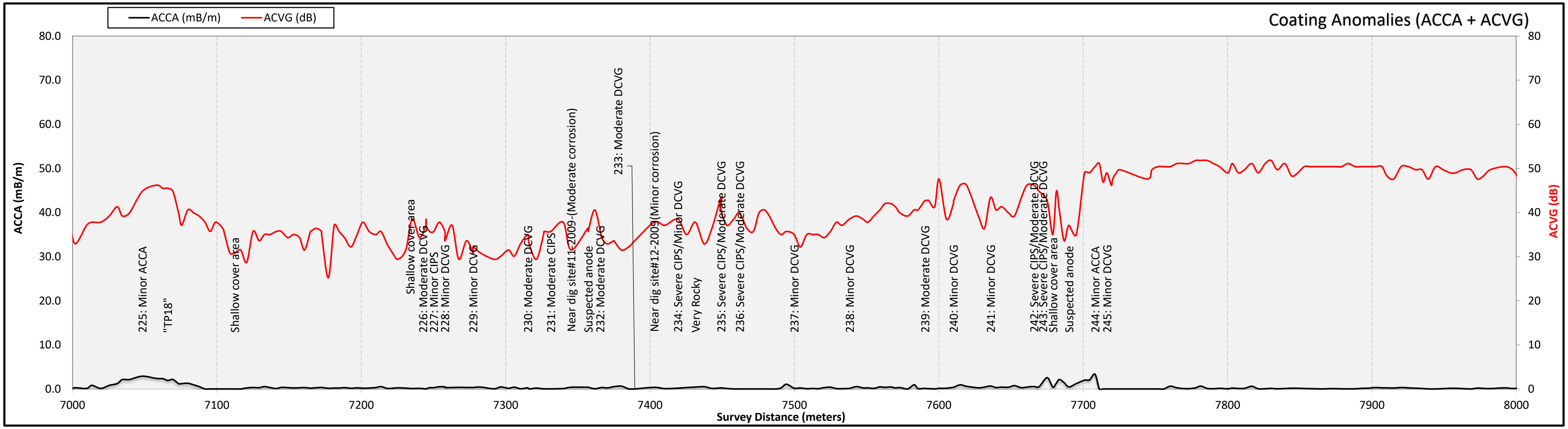
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

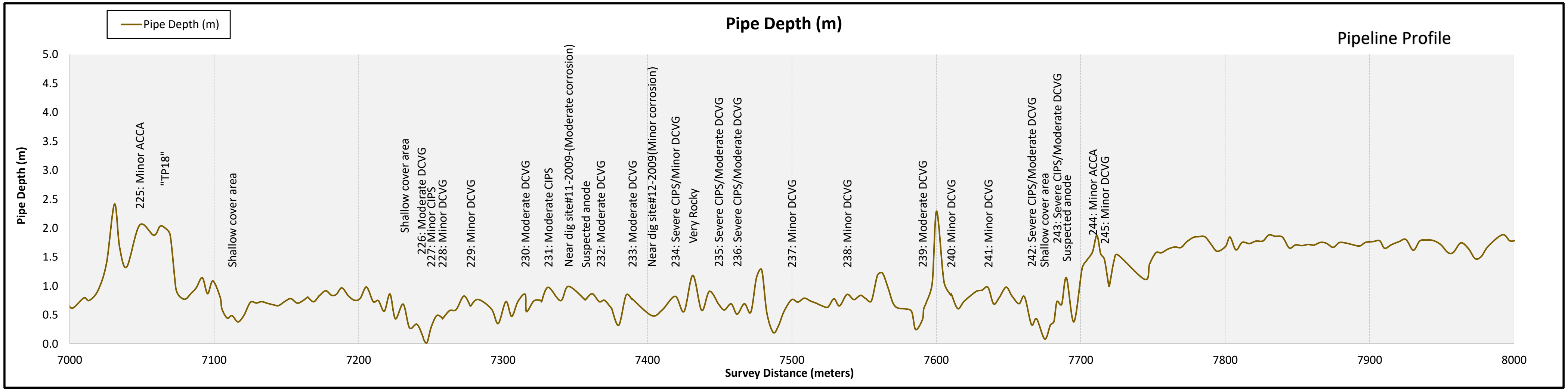




AEGION
Stronger. Safer. Infrastructure.
corrpro

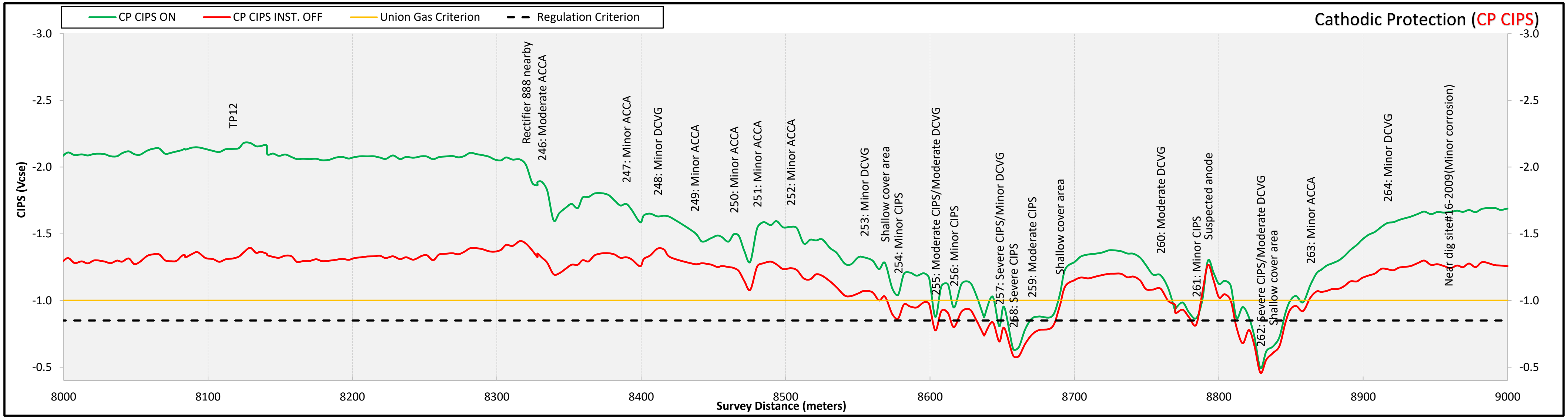
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

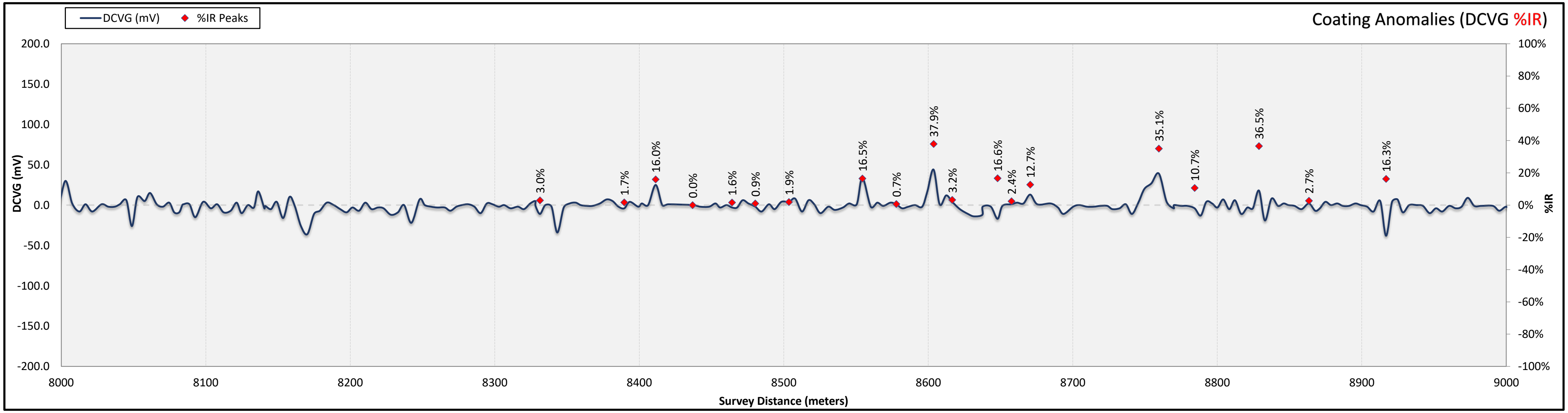




AEGION
Stronger. Safer. Infrastructure.
corrpro

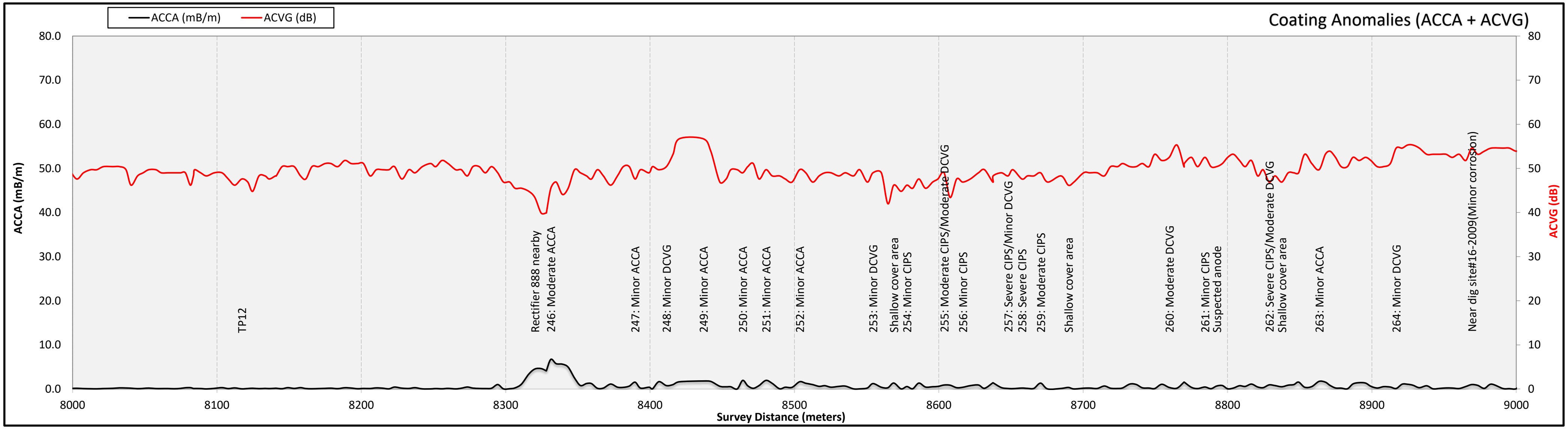
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

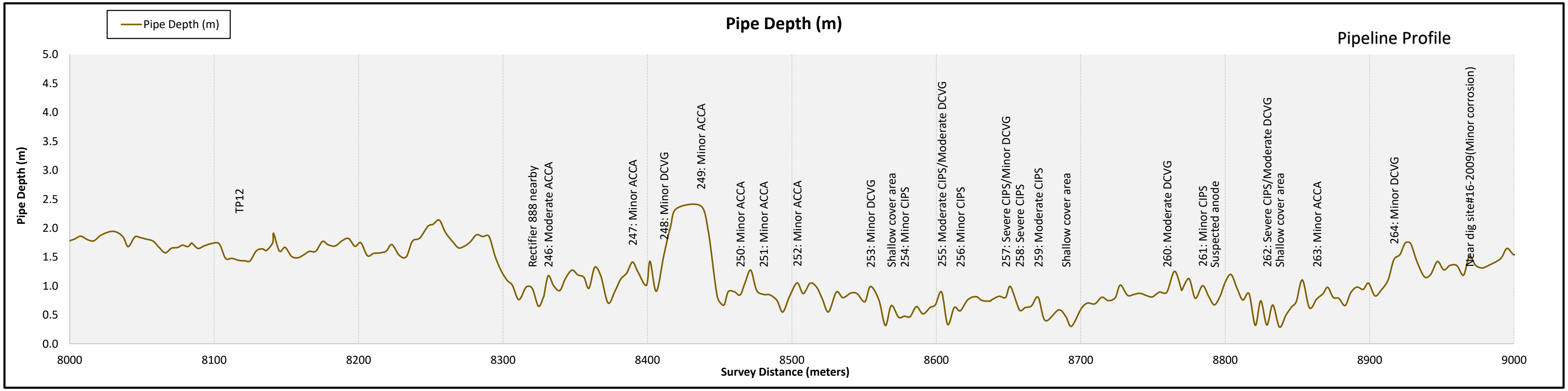




AEGION
Stronger. Safer. Infrastructure.
corrpro

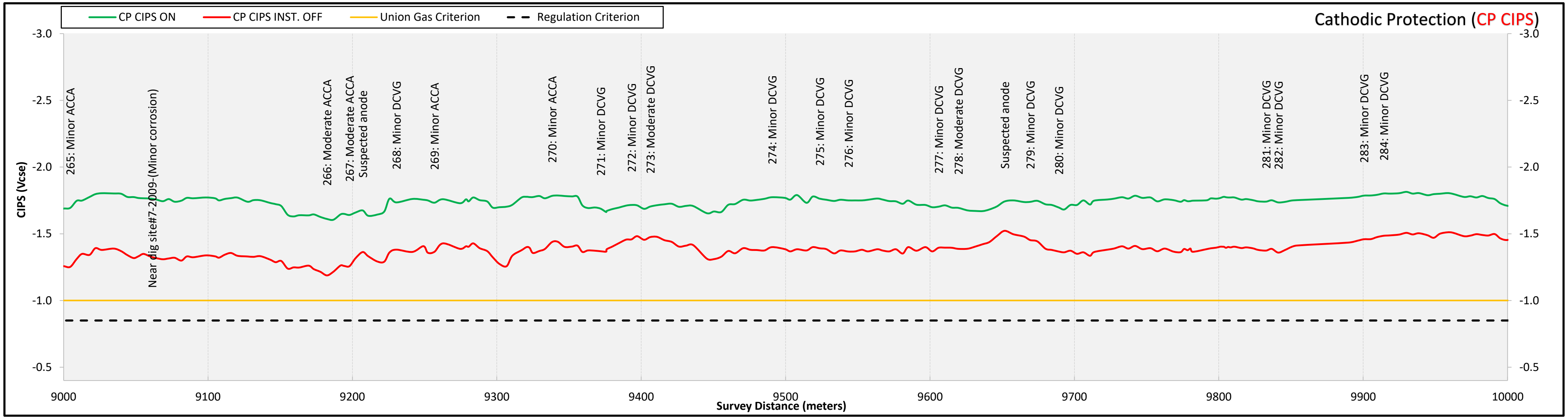
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

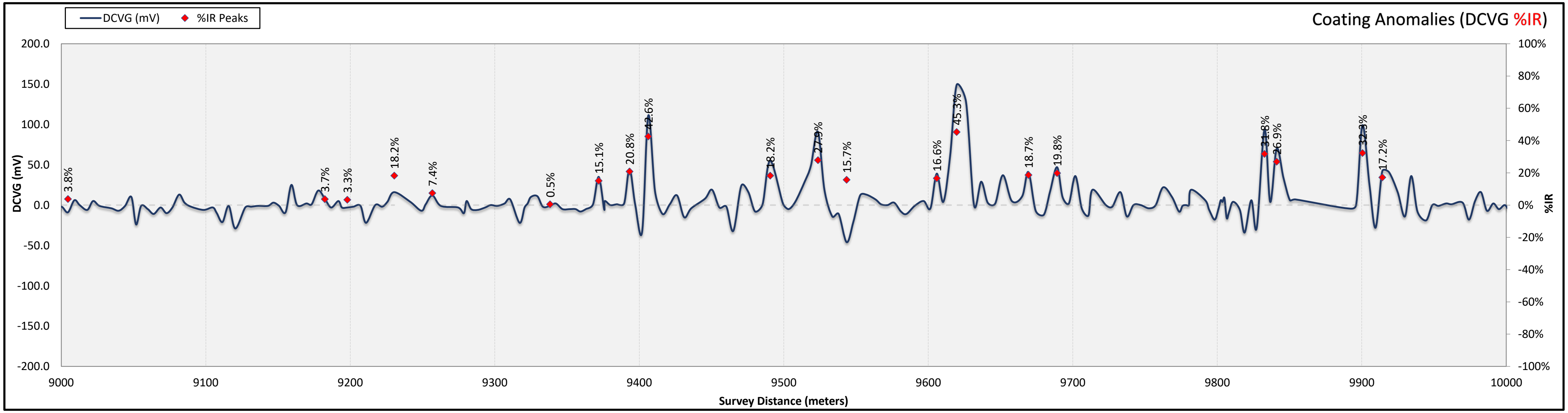




AEGION® Stronger. Safer. Infrastructure.® corrpro®

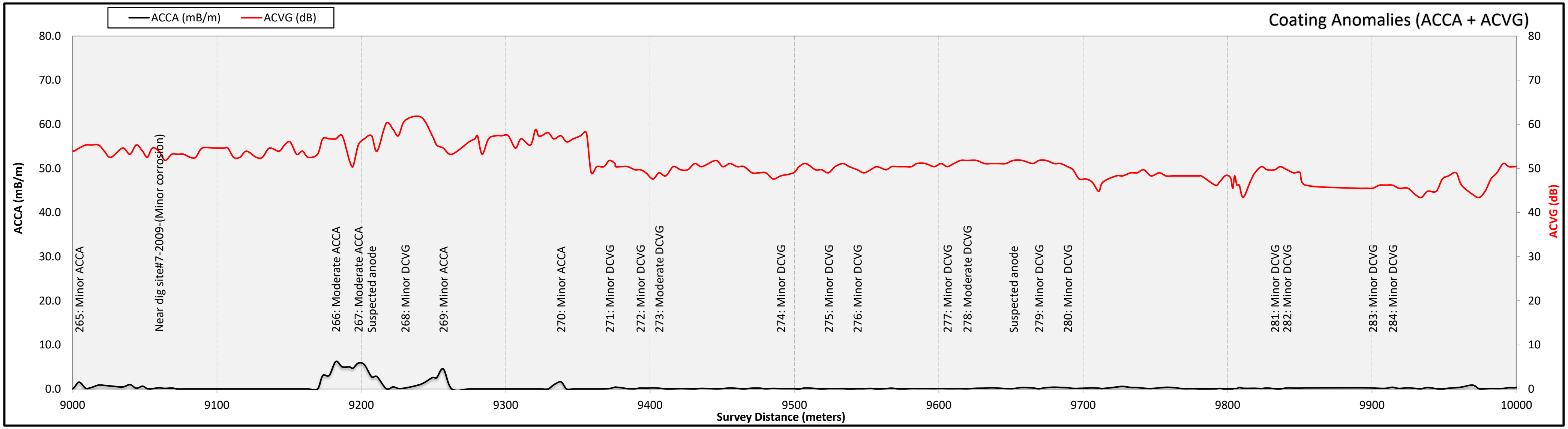
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

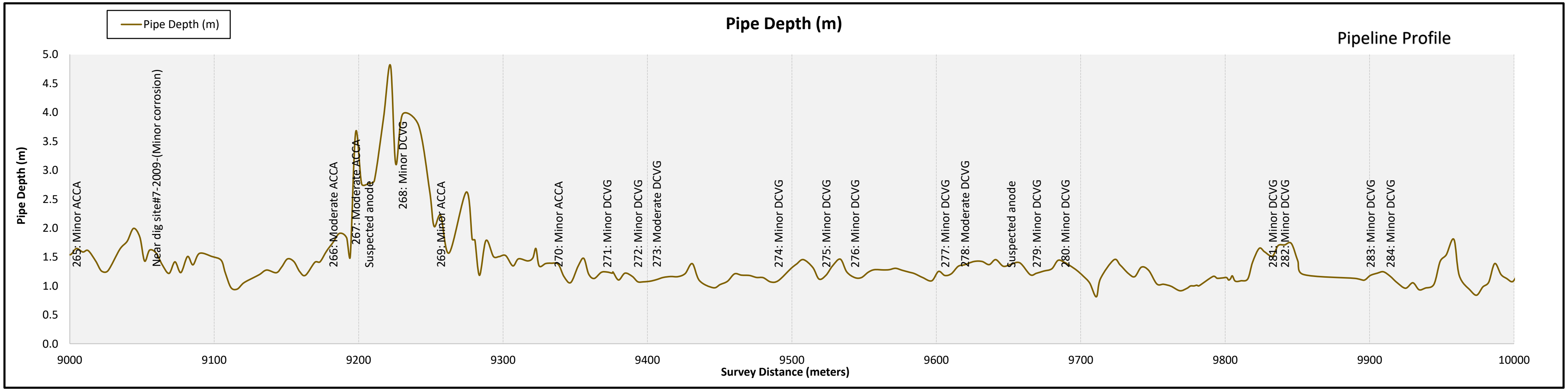




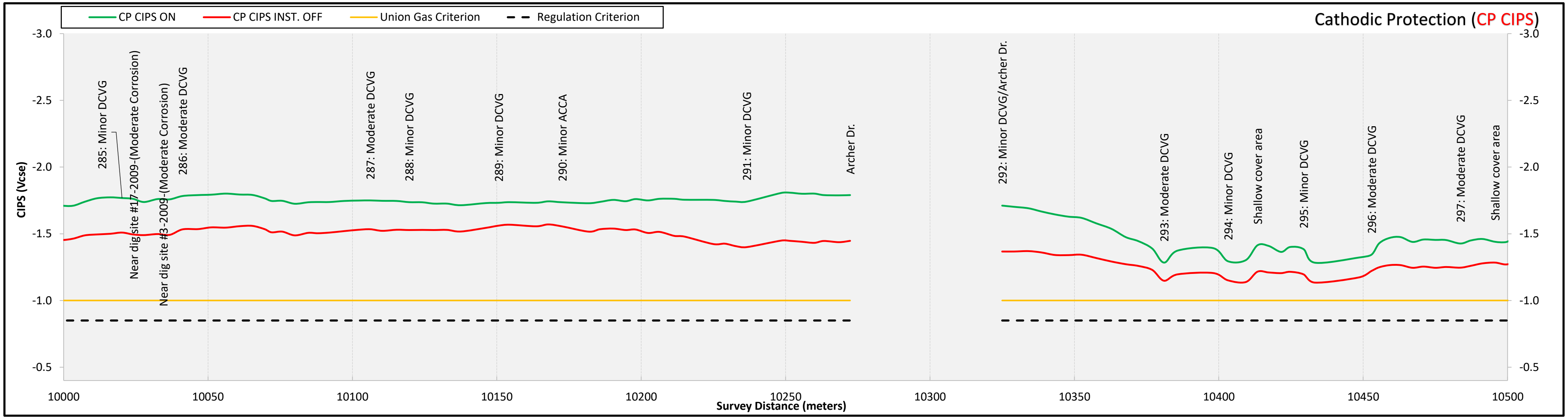
AEGION
Stronger. Safer. Infrastructure.
corrpro

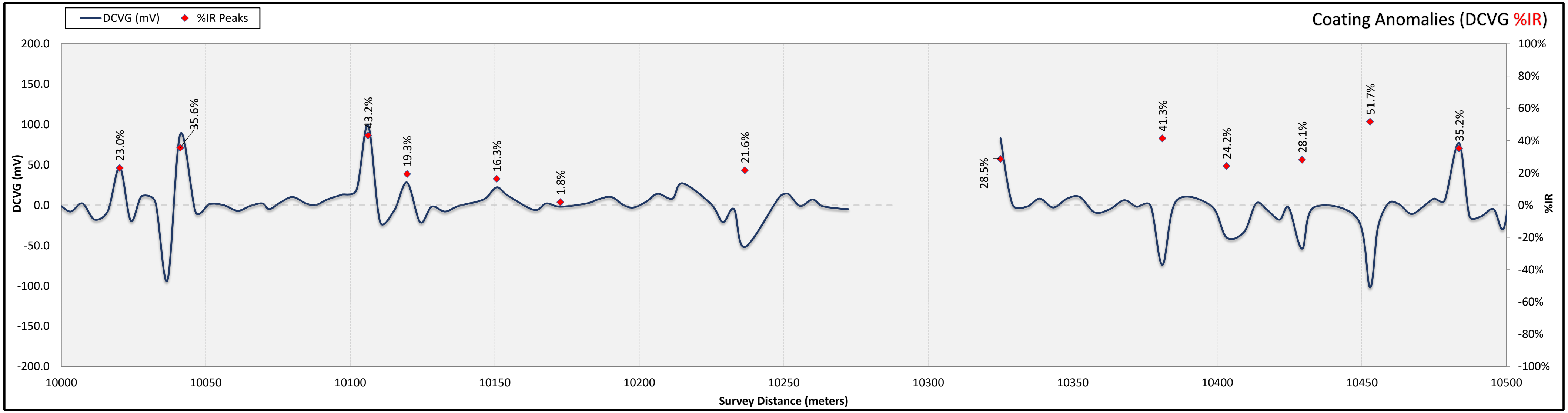
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700





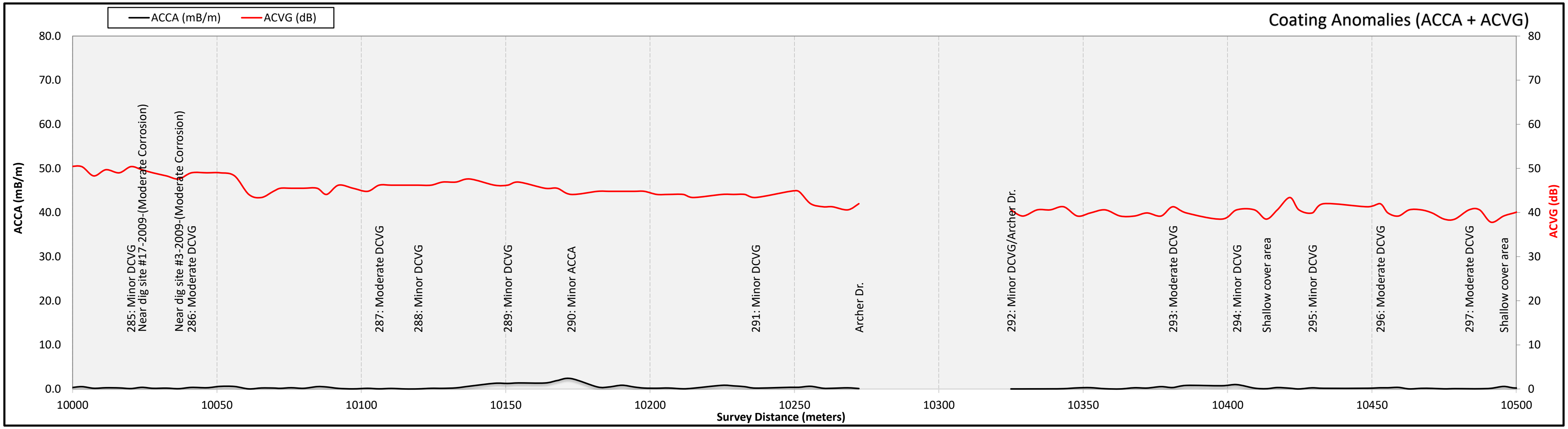
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

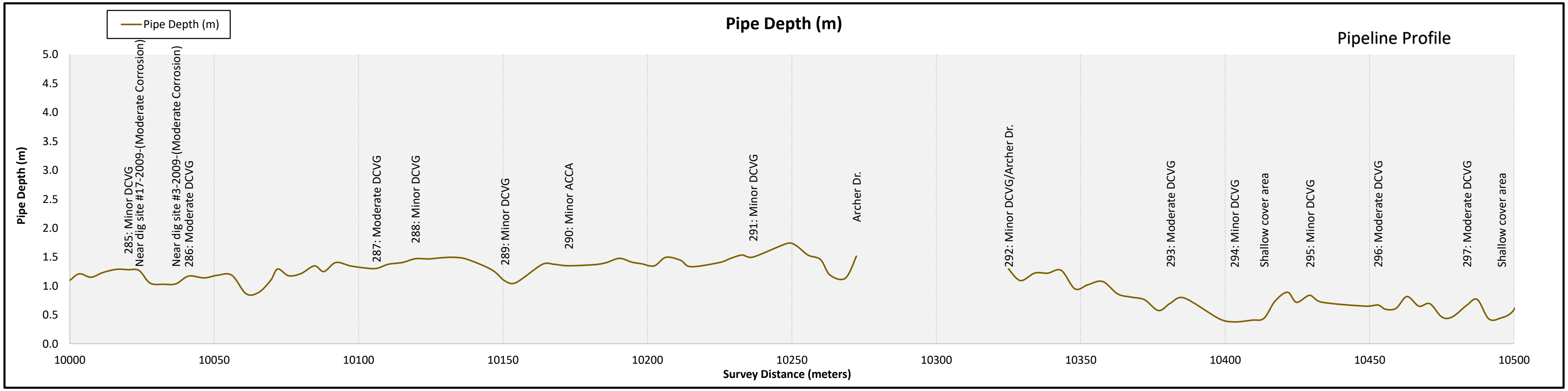




AEGION
Stronger. Safer. Infrastructure.
corrpro

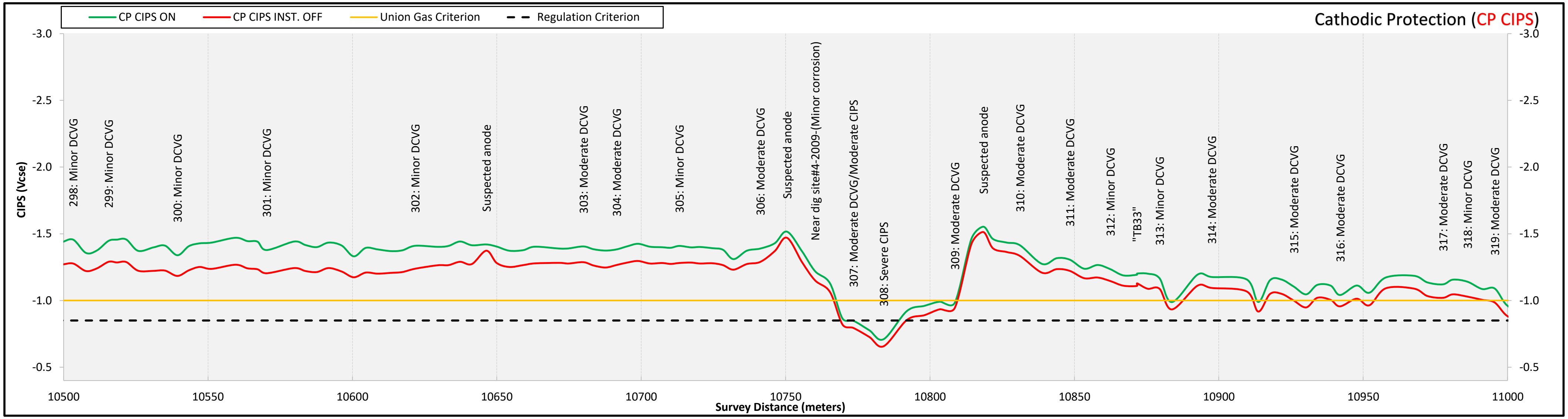
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

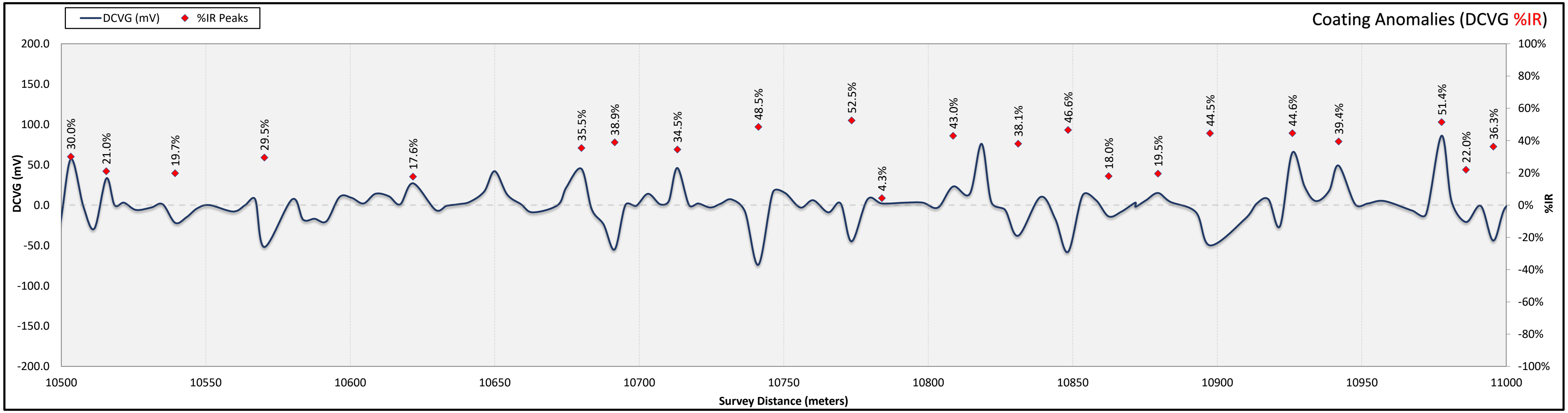




AEGION
Stronger. Safer. Infrastructure.
corrpro

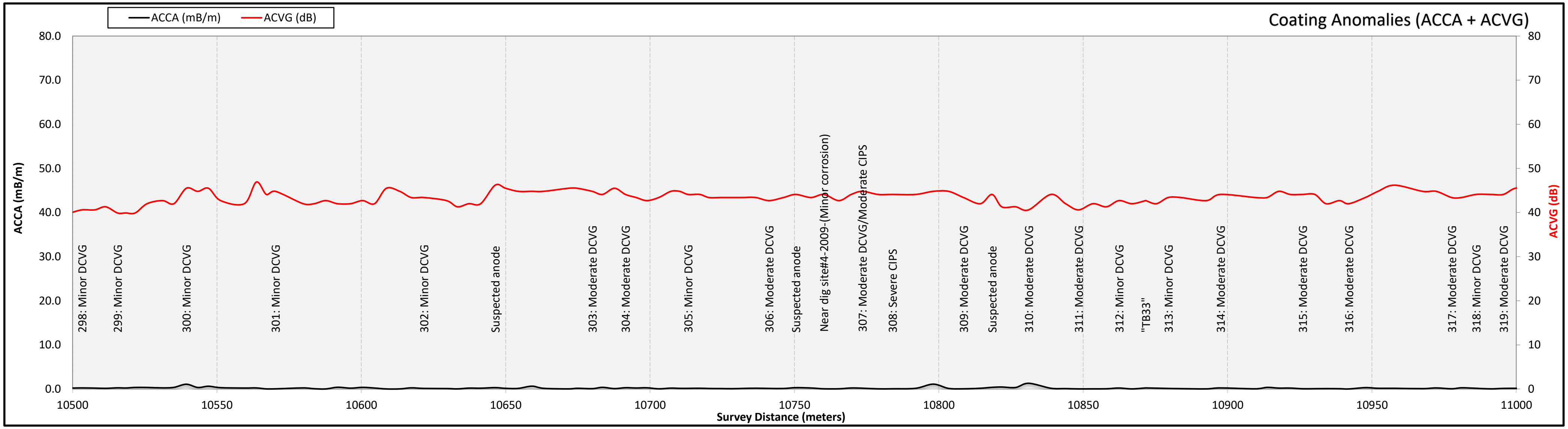
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

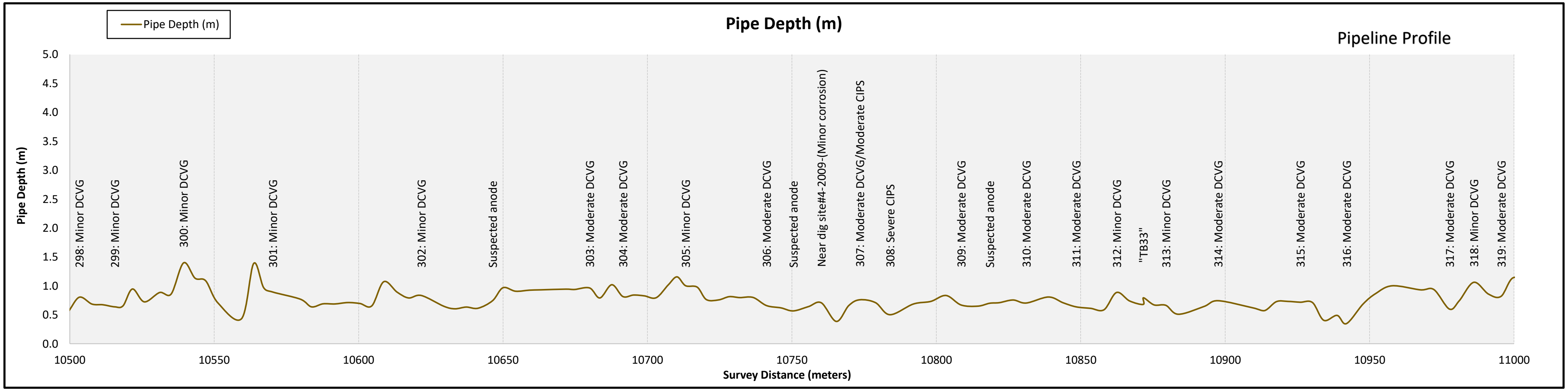




AEGION® Stronger. Safer. Infrastructure.® corrpro®

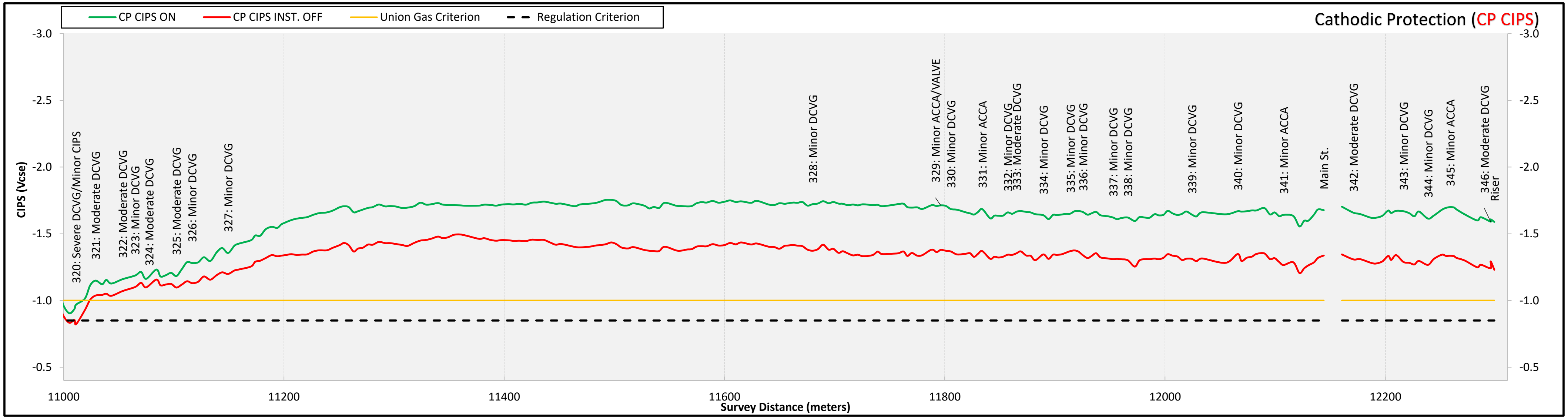
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

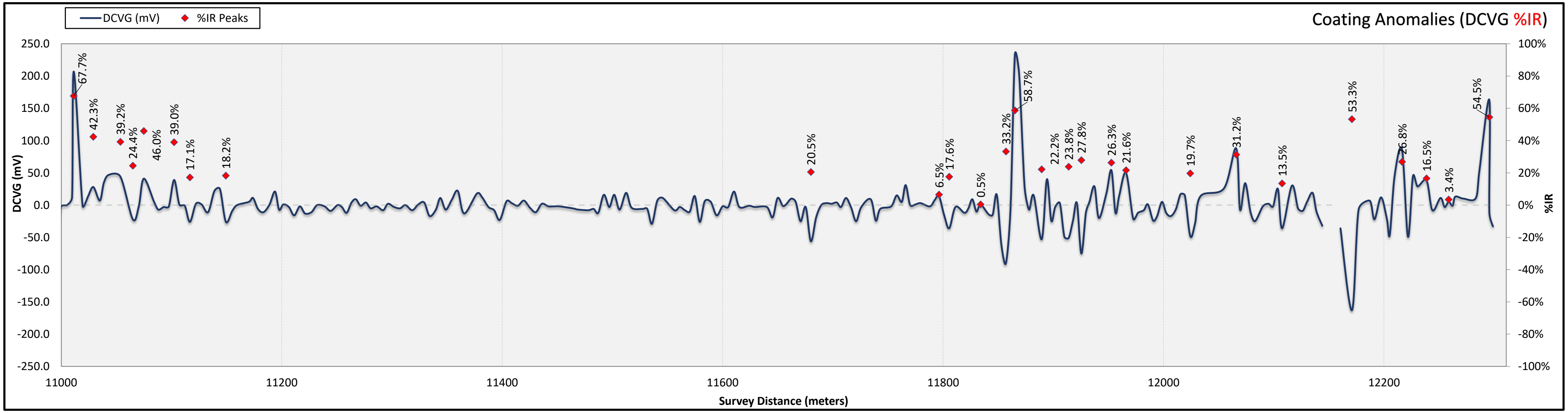




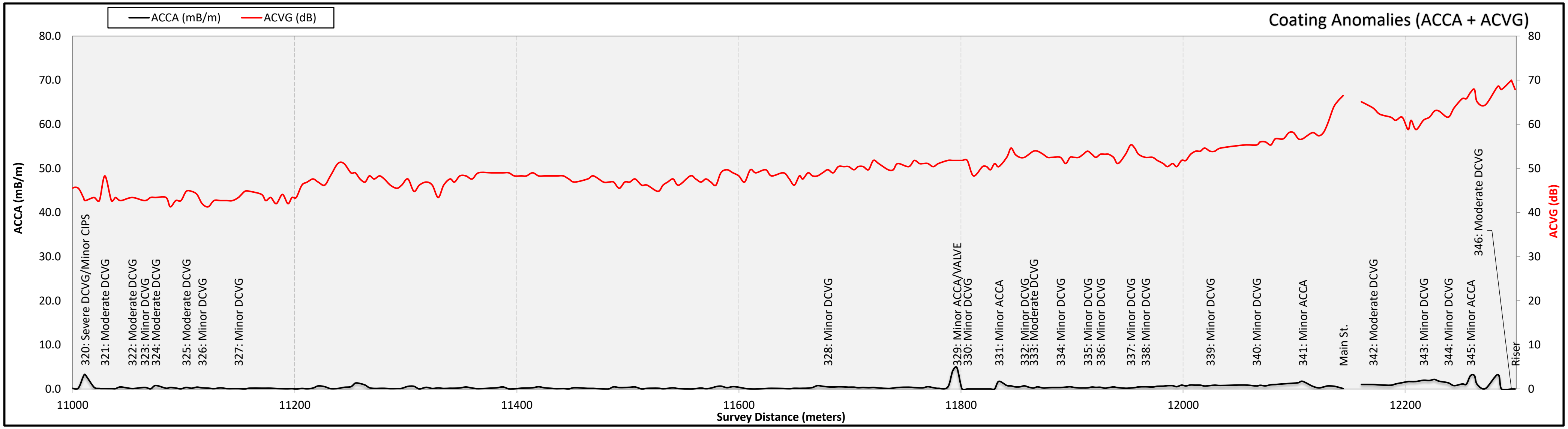
AEGION® Stronger. Safer. Infrastructure.® corrpro®

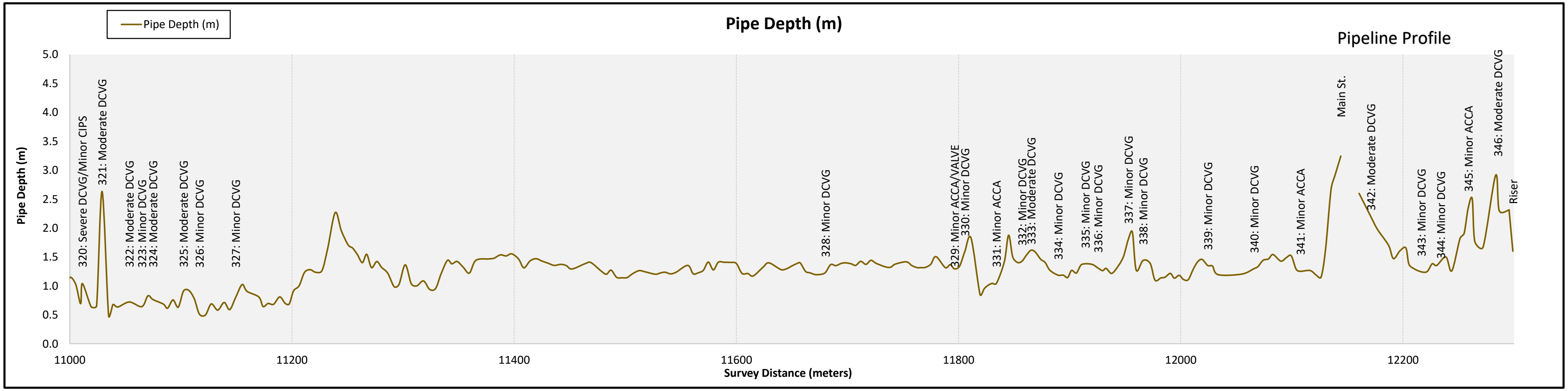
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700

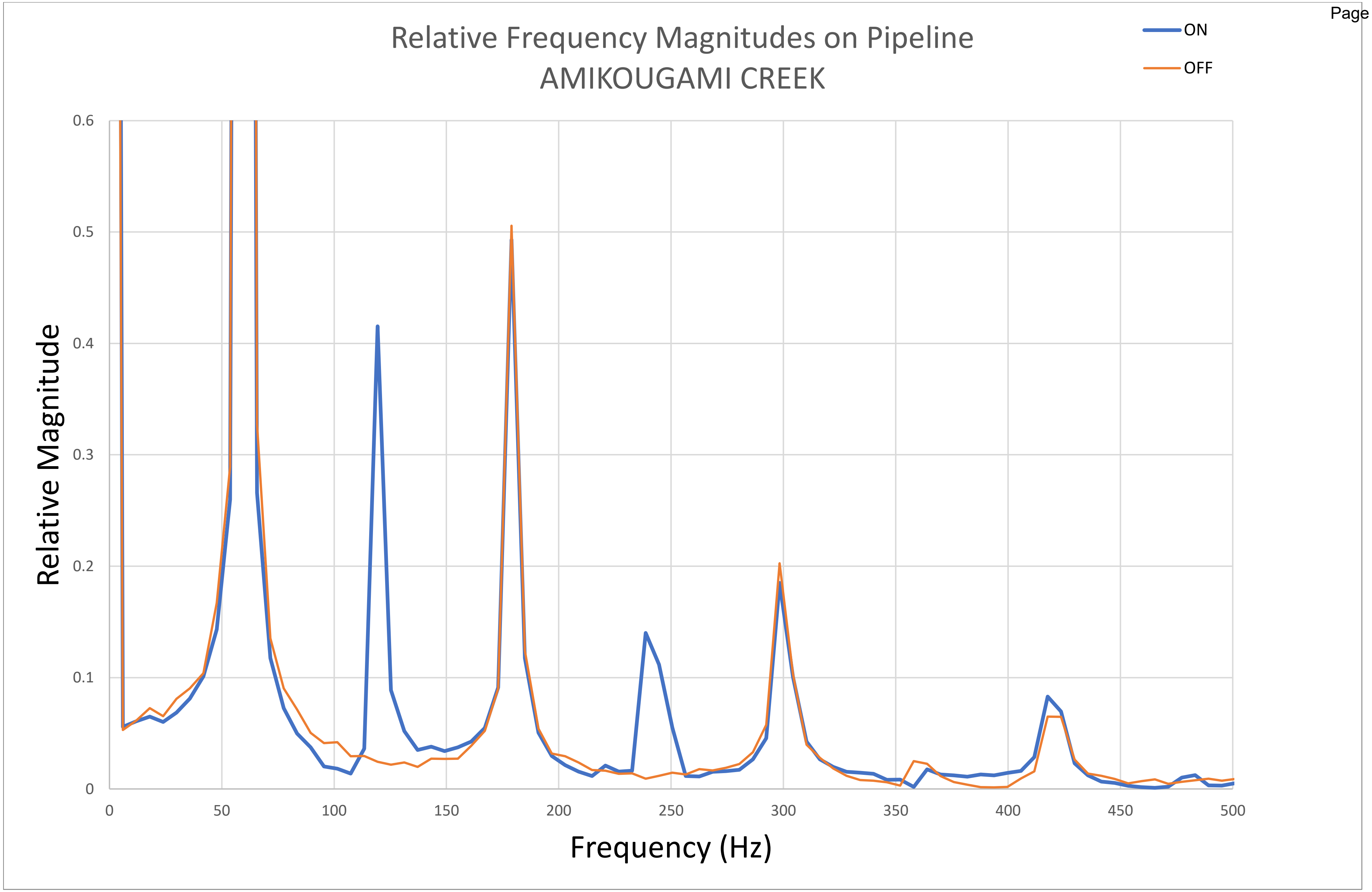


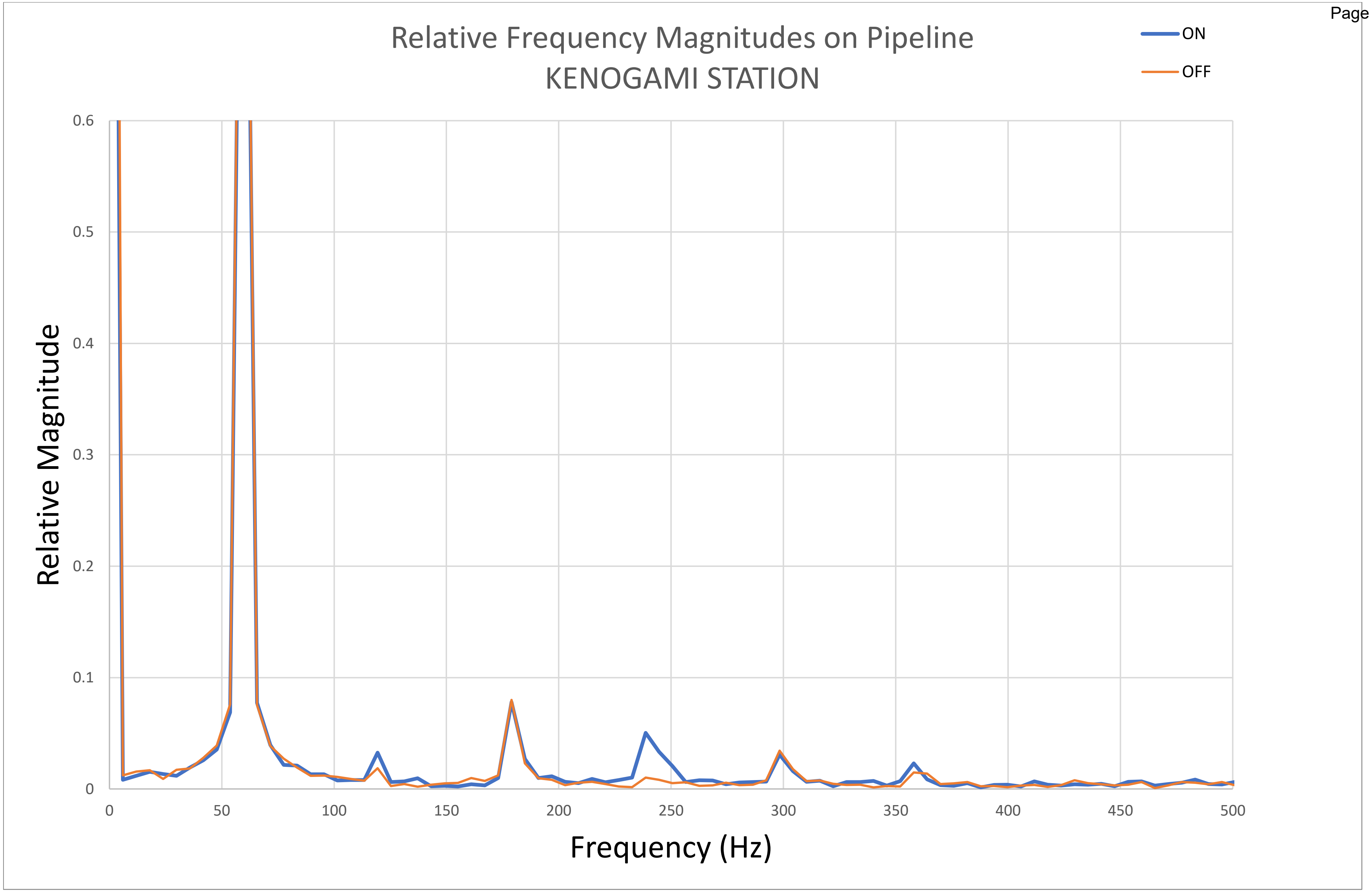


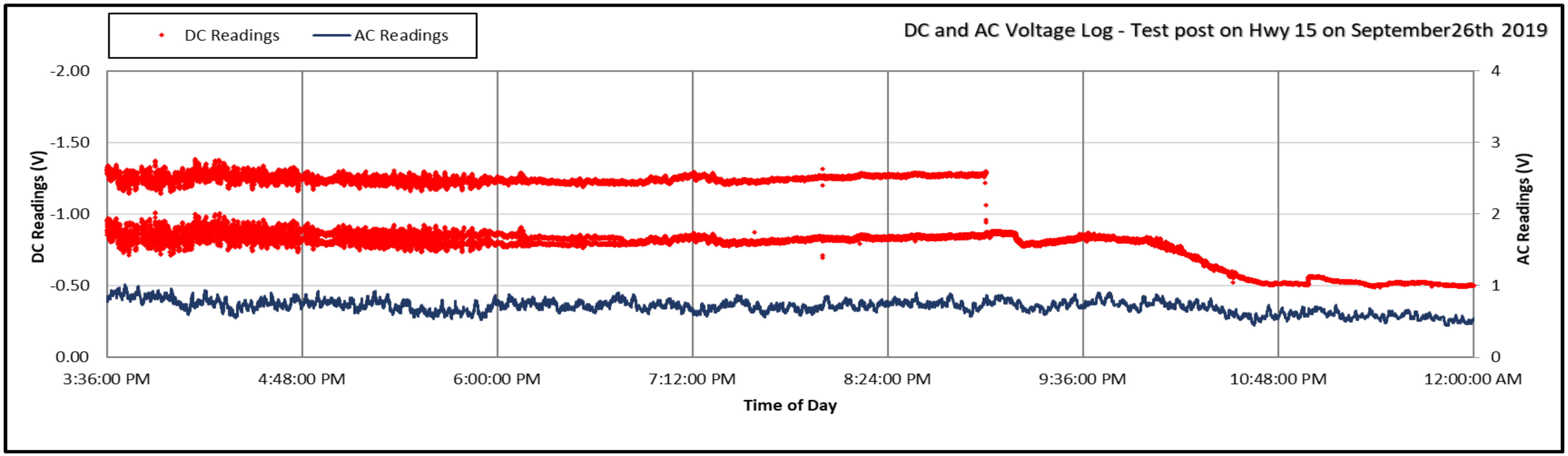
Mississauga Office
3-7895 Tranmere Drive
Mississauga, ON, L5S1V9
Tel: 905.677.2700






Relative Frequency Magnitudes on Pipeline
AMIKOUGAMI CREEK
ON
OFF
Relative Magnitude
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250
300
350
400
450
500
Frequency (Hz)


Relative Frequency Magnitudes on Pipeline
KENOGAMI STATION
ON
OFF
Relative Magnitude
0.6
0.5
0.4
0.3
0.2
0.1
0
0
50
100
150
200
250
300
350
400
450
500
Frequency (Hz)


DC Readings
AC Readings
DC and AC Voltage Log - Test post on Hwy 15 on September26th 2019
-2.00
-1.50
-1.00
-0.50
0.00
4
3
2
1
0
DC Readings (V)
AC Readings (V)
3:36:00 PM
4:48:00 PM
6:00:00 PM
7:12:00 PM
8:24:00 PM
9:36:00 PM
10:48:00 PM
12:00:00 AM
Time of Day

APPENDIX 3

EQUIPMENT INSPECTION TOLERANCES

XLI Inspection Tolerances

For a Corrpro ROW Geodetic inspection there are two tolerances to consider, Line Locator tolerance and GPS Tolerance as they are separate and independent.

Line Locator Tolerances

Corrpro's Line Locator accuracy varies with pipeline cover, as is presented in Table 4.1 below.

Table 4.1: Pipeline Line Locator Accuracy

Item	Accuracy
Maximum Depth of Cover	9+ meters (30+ feet) typical conditions (>100' has been recorded)
Minimum Signal Strength	100 mA
Range	1 to 5 + Km (depends on soil conditions and quality of coating)
Pipe Cover Accuracy (Conductive)	+/- 2.5% to 3 meters (10 feet) * +/- 5.0% to 9 meters (30 feet) * Note: Less than +/- 10 cm error when DOC < 3 meters
Pipe Cover Accuracy (Inductive)	Tolerances doubles when using inductive line illumination, i.e.; +/- 5.0% to 3 meters (10 feet) * +/- 10.0% to 9 meters (30 feet) *
Current Accuracy	+/- 1.5% of calculated value *
* Pipe cover and current accuracy is dependent on numerous factors and are achievable approximately 80% of the time.	

Please note that pipe cover accuracy doubles when the line is located using an inductive connection rather than a conductive connection. Figure 4.1 represents the conductive locator accuracy up to 9 meters of depth.

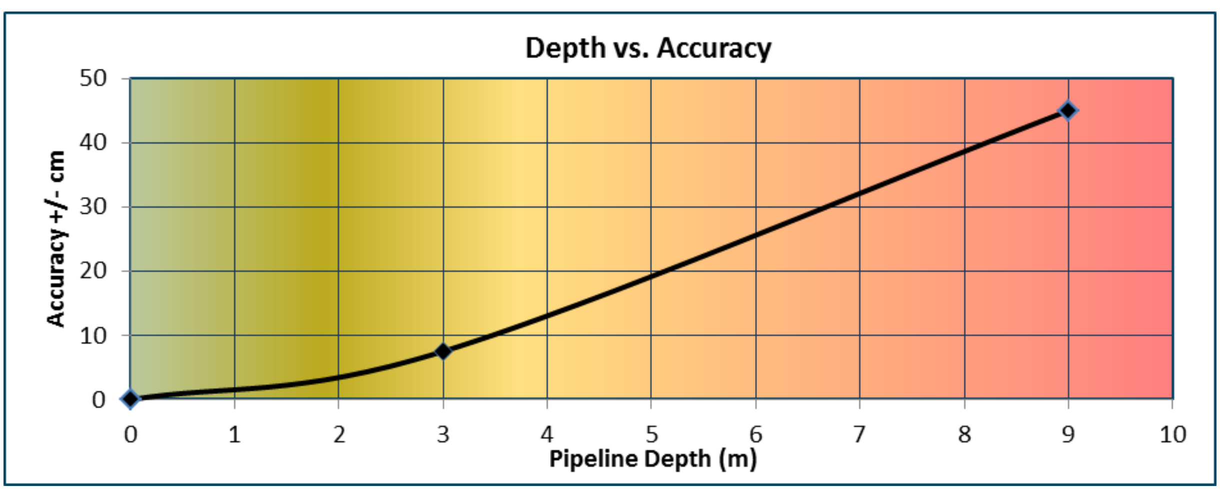


Figure 4.1: Conductive Locate Accuracy vs. Pipeline Depth (up to 10 meters)

A more detailed pipeline accuracy chart is presented below, focusing on the depths up to 3 meters (~ 10 feet).

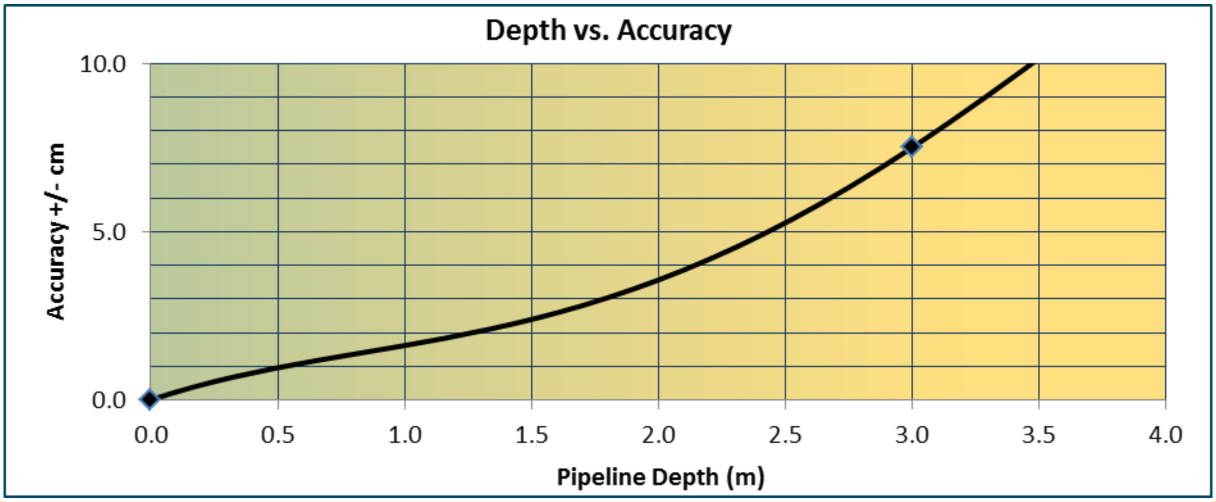


Figure 4.2: Conductive Locate Accuracy vs. Pipeline Depth (up to 3.0 meters)

GPS Tolerances

There are several levels of GPS inspection services provided by Corrpro, which are presented in table 4.2 below:

Table 4.2: GPS Specifications	
GPS	**Accuracy**
Pipeline Horizontal & Vertical Position (GPS) RTK Static GPS[1],[2]	Horizontal: +/- 10 mm (~ 3.9”) 98% of the time Vertical: +/- 20 mm (~ 7.9”) 98% of the time
Pipeline Horizontal & Vertical Position (DGPS) RTK OmniStar HP[1],[3]	Horizontal: +/- 20 cm (~ 7.9”) 98% of the time Vertical: +/- 40 cm (~ 15.7”) 98% of the time
Pipeline Horizontal & Vertical Position (DGPS) NTRIP[1],[4]	Horizontal: +/- 20 cm (~ 7.9”) 98% of the time Vertical: +/- 40 cm (~ 15.7”) 98% of the time
Pipeline Horizontal & Vertical Position SBAS (WAAS) [1]	Horizontal +/- 60 cm (~ 2’) 95% of the time Vertical +/- 120 cm (~ 4’) 95% of the time
Horizontal Accuracy (Autonomous, no Differential Correction) [1]	Horizontal +/- 2.5 m (~ 8.2’) 95% of the time Vertical +/- 5.0 m (~ 16.4’) 95% of the time
* DOC and current accuracy is dependent on numerous factors and are achievable approximately 80% of the time. [1] Depends on multipath environment, number of satellites in view, satellite geometry and ionospheric activity. [2] Depends also on baseline length. [3] Requires a subscription from OmniSTAR. [4] Requires a NTRIP subscription.	

Differential GPS (DGPS) refers to a technology that is used to reduce the errors created by atmospheric conditions between the satellite and receiver. The fundamental idea is that a ground station, which is positioned on a known coordinate, measures data from the satellites and compares it with the known position data. The ground station then transmits correction signals to GPS receivers based on the difference between what is received and what it expected to receive.

Real Time Kinematic (RTK) Differential GPS Correction uses a ground station in the immediate vicinity of the inspection (typically <10 Km away). The ground station broadcasts correction information via UHF or VHF radio frequency to the inspection receiver to incorporate corrections. NTRIP cellular connections can also be used to broadcast the correction information. The RTK method can produce coordinates in real time that are accurate to within 10 cm (horizontal and vertical) or better under ideal conditions.

GPS Latitude & Longitude

The meter was originally defined (by the French, around the time of their revolution) so that ten million of them would take you from the equator to a pole. That's 90 degrees, therefore one degree of latitude covers about 10^7/90 = 111,111 meters. Furthermore, a degree of longitude (east-west) is about the same or less in length than a degree of latitude, because the circles of latitude diminish down to the earth's axis as we move from the equator towards either pole (see Figure 4.3 below).

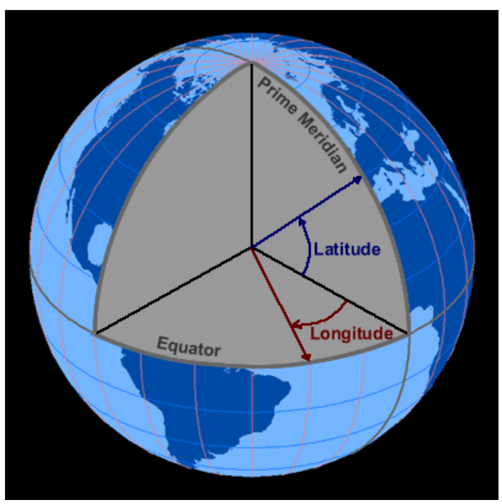


Figure 4.3: Earth Latitude and Longitude

The distance per degree is associated with the distances provided in Table 4.3. Each longitude degree represents a distance of 111.32 km (The radius of the earth is 6,378,160 meters; therefore, dividing by 360 degrees provides the result that each degree corresponds to a distance of 111.32 km). Corrpro reports all Latitude and Longitude coordinates to six decimal places. Table 4.3 provides the distance associated with each 0.000001 Degree change.

Table 4.3: GPS Latitude Accuracy		
One Longitude Degree @	**Distance (km)**	**Sixth Decimal Place Distance (cm)**
Equator (0 degrees Latitude)	111 km	11.1 cm
15 degrees	107 km	10.7 cm
30 degrees	96 km	9.6 cm
45 degrees	79 km	7.9 cm
60 degrees	56 km	5.6 cm
75 degrees	29 km	2.9 cm
89 degrees (one degree from north pole)	2 km	0.2 cm

Six decimal places indicate the latitude is within 0.11 meters of the true inspection point location and that the longitude is at least within 0.11 meters of the true inspection point location. Longitude decreases is length as the distance from the equator decreases, therefore at six decimal places, the longitude is 0.11 meters or less from the true inspection point location.

Voltage Inspection Accuracy

For the AC and DC Corrpro above ground inspection specifications, see Table 4.4 below:

Table 4.4: XLI Voltage Specifications	
DC Voltage Specifications	
Input Impedance:	10 MΩ (optional external 100 MΩ attachment)
Range:	+/- 9.58 Volts
Analog noise:	200 nano-Volts
AC rejection:	>100 db.
Effective resolution:	4 decimals at 24.0 bits with measurements taken 880 times per second
Accuracy:	0.03% of DC range (+/-1 mV @ 9.58 Volts)
AC Voltage Specifications	
Input Impedance:	10 MΩ (scalable external option for 100+ MΩ)
Range:	+/- 1 Volt
Accuracy:	+/- 1% (+/-1 mV @ 1.0 Volts)

CP CIPS Tolerances

Half cells have to be within 5 mV of a master reference cell. Therefore, the difference between a pair of inspection half cells must always be within 10 mV and each must be within 5 mV of the same reference cell to be used for inspection purposes.

Metallic IR Drop

The Metallic IR Drop is the drop in the pipeline potential from the far test station to the near test station. If the 'Instant OFF' metallic IR drop exceeds 6 mV, then the source of interference should be investigated before continuing the inspection. The 6 mV value is a guideline, to confirm interference the pipe diameter, wall thickness, and length between test posts need to be determined in order to calculate how much current the 6 mV represents. The current is the concern, not the voltage.

If an 'ON' pipe to soil metallic IR drop does not exceed 10 volts, then it is not likely any significant coating faults are located on the section of pipe. Figure 4.5 below represents a 50 mV gain in 'ON' pipe to soil potentials from the far test station to the near test station, which means 50 mV has come onto the pipe somewhere along this section.

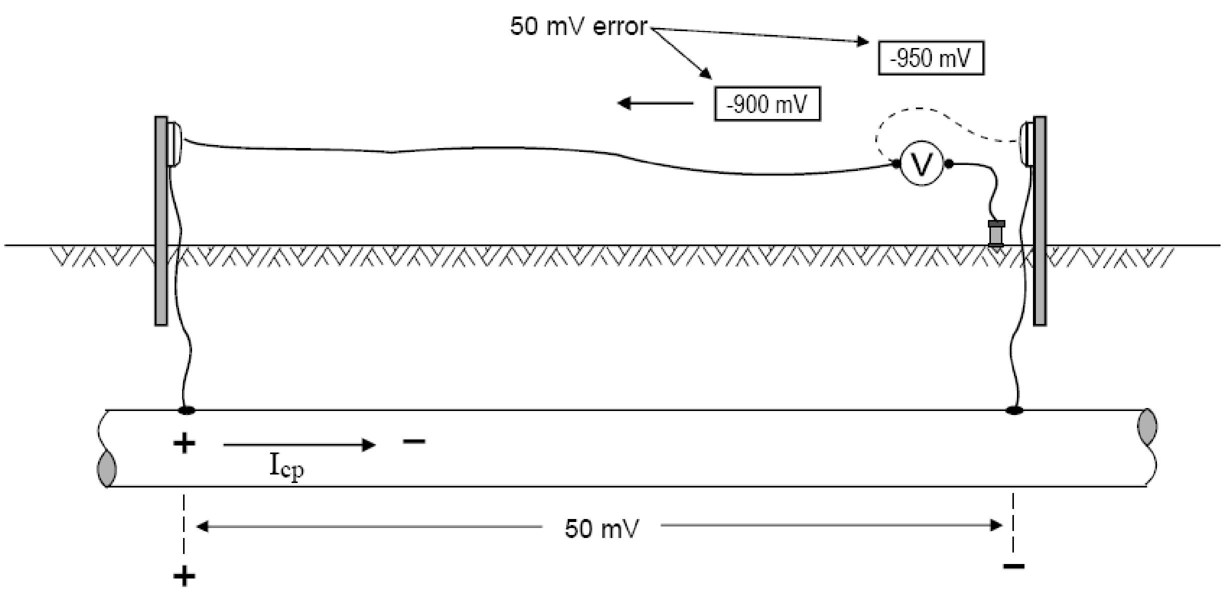


Figure 4.5: Metallic IR Drop

Electrolyte (Soil) IR Drop

Electrolyte IR Drop is the drop in 'ON' pipe-to-soil potentials as current flows through resistive earth and towards the pipeline. If the pipe to soil potential in Figure 1.6 is measured as -890 mVcse and each equipotential line represents a 10 mV drop in potential then the "true" pipe-to-soil potential is -790 mVcse (ten equipotential lines, each representing a 10 mV drop). Note that the potential does not go to zero just outside the pipe; most will be lost over the coating fault (the highest resistance). For example, 785 mVcse could be consumed by the pipe coating fault resistance, leaving 5 mV left to be lost over the remaining metallic path (from the coating fault through the metal pipe, and rectifier connecting wire).

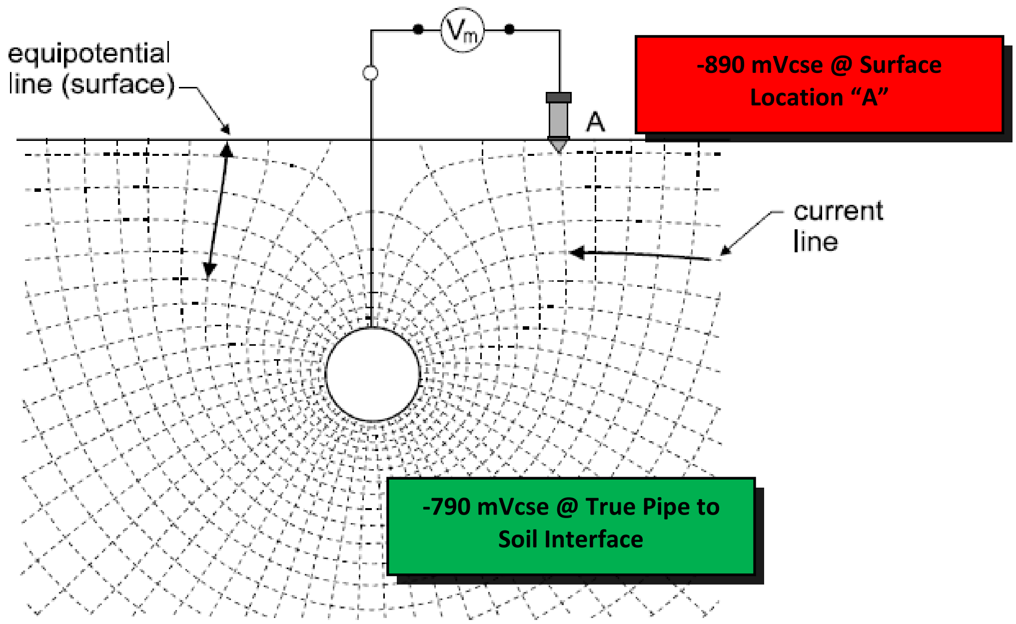


Figure 4.6: Electrolyte IR Drop

CP CIPS Measurement Length

When measuring a potential at one location, the amount of pipe sampled in the measurement is considered the length of pipe encompassed by a 120º arc centered on the reference electrode as shown in Figure 4.7 below.

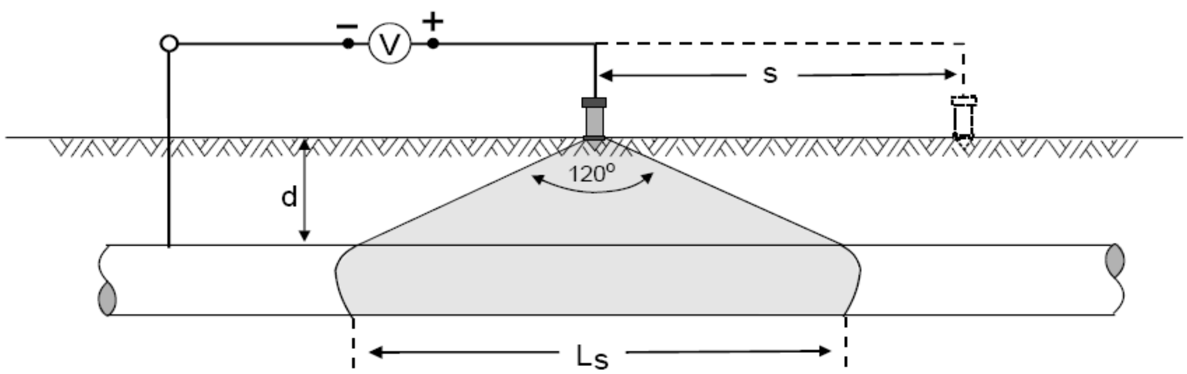


Figure 4.7: Pipe to Soil Measurement Area

Hence, the length of pipeline sampled (Ls) in a potential measurement is given by the equation:

Ls = 3.5d + 1

Parallel Pipeline Resolution

If the pipeline separation is greater than two times the depth of cover (DOC), then the above ground inspection can identify each line independently (see Figure 1.8 below, since “s” is more than twice the distance of “t”, the pipe to soil potentials (“V”) will be representative of pipe one only. Please note that “s” and “t” are from pipe centerline to centerline).

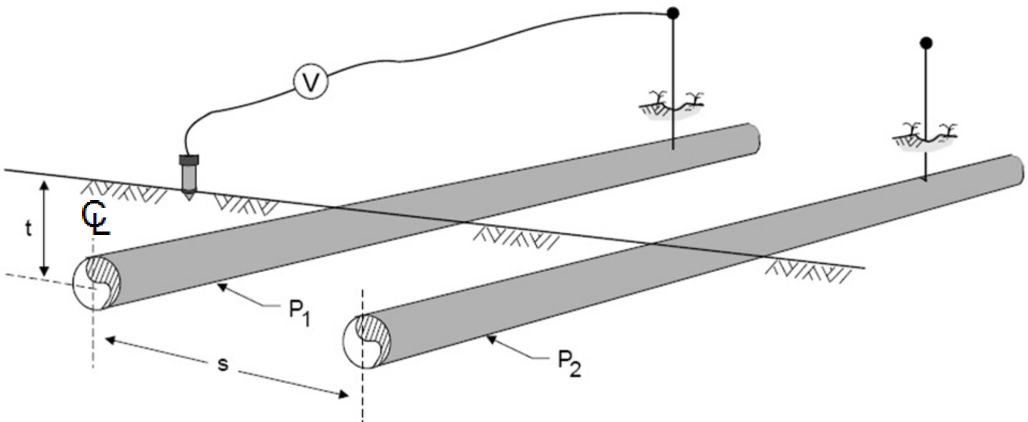


Figure 4.8: Parallel Pipelines

Note: It may be able to distinguish some pipelines, when conditions are favorable (i.e. good coating, limited interference, shallow DOC), and if the separation between them is equal or greater than DOC.

Stationary Data Logger (SDL) Inspection Tolerances

Fluctuations in ‘ON’ & ‘Instant OFF’ potentials which are greater than +/- 30 mV could be indicative of stray current, and therefore the inspection data may require a correction to be applied.

APPENDIX 4

DEFINITIONS

ABOVE GROUND INSPECTION DEFINITIONS

It is important to note that once an inspection has identified an integrity concern, it is classified as an "indication" rather than a "defect". ASME B31.8s defines an "indication" as:

Indication: Finding of a non-destructive testing technique. It may or may not be a defect.

As can be seen in Figure 5 above, an "indication" is not identified as a "defect" until the pipeline undergoes "examination" and "evaluation". These terms are defined in order of hierarchy:

Examination: Direct physical inspection of the pipelines by a person and may also include the use of non-destructive examination techniques (NDE).

Evaluation: Analysis and determination of the facility's fitness for service under the current operating conditions.

Defect: An imperfection of a type and magnitude exceeding acceptable criteria.

Therefore, no indication or anomaly from an NDE inspection can be called a defect or specific type of integrity threat until direct physical inspection by a person has been conducted. Corrpro uses the term "Anomaly" to define an NDE inspection indication. NACE SP0502, Pipeline External Corrosion Direct Assessment (ECDA) Methodology, defines the term Anomaly as;

Anomaly: Any deviation from nominal conditions in the external wall of a pipe, its coating, or the electromagnetic conditions around the pipe.

Lastly, in Canada, CSA Z662 has defined "Indication" and "Defect" with the same objective as presented by ASME B31.8s above.

A

Alternating Current Current Attenuation (ACCA) Inspection: A method of representing the severity of current loss along the line as a result of coating Disbondment

Alternating Current Pipe to Soil Potential (AC PSP) Inspection: A potential inspection performed on a buried or submerged metallic pipeline, in order to obtain valid AC structure-to-electrolyte potential measurements at a regular interval sufficiently small to permit a detailed assessment.

Alternating Current Voltage Gradient (ACVG) Inspection: A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity

Anode: The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode.

Anomaly: Any deviation from nominal conditions in the external wall of a pipe, its coating, or the electromagnetic conditions around the pipe.

Appurtenance: A component that is attached to the pipeline; e.g., valve, tee, casing, instrument connection.

B

B31G5: A method (from the ASME standard) of calculating the pressure-carrying capacity of a corroded pipe.

C

Cathode: The electrode of an electrochemical cell at which reduction is the principal reaction. Electrons flow toward the cathode in the external circuit.

Cathodic Disbondment: The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

Cathodic Protection (CP): A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Cathodic Protection (CP) Coupon: A metal specimen made of similar material as the structure under investigation, which is connected to the external surface of, and immersed in the electrolyte adjacent to, the structure being protected by cathodic protection.

Cell-to-Cell Inspection: An inspection measuring the potential difference between two reference electrodes. Cell-to-cell inspections include ACVG, DCVG, side-drain, and hot-spot inspections.

Class location: A geographical area classified according to its approximate population density and other characteristics that are to be considered when designing and pressure testing piping to be located in the area.

Class location assessment area: A geographical area that extends 200 m on both sides of the centerline of the pipeline.

Class location assessment area, undeveloped: A class location assessment area that is:

- At least 400 m long;
- Free of dwelling units, other buildings intended for human occupancy, places of public assembly, and industrial installations; and
- Unlikely to be developed.

Class location end boundary: The demarcation between different class locations.

Close-Interval Potential Survey (CIPS) (also Close - Interval Inspection [CIS]): A potential inspection performed on a buried or submerged metallic pipeline, in order to obtain valid DC structure-to-electrolyte potential measurements at a regular interval sufficiently small to permit a detailed assessment.

Close-Interval Inspection with Laterals: A hybrid inspection that simultaneously measures the structure-to-electrolyte potentials and the potential at a point lateral to the pipeline.

Coating: A liquid, liquefiable, or mastic composition that, after application to the surface, is converted into a solid protective, decorative, or functional adherent film. For the purposes of this standard, coating refers to a dielectric material applied to a structure to separate it from the environment.

Coating Fault: Any imperfection or defect in the coating, including disbonded areas and holidays.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Corrosion Potential (Ecorr): The potential of a corroding surface in an electrolyte relative to a reference electrode under open-circuit conditions (also known as rest potential, open-circuit potential, or freely corroding potential).

Criterion: Standard for assessment of the effectiveness of a CP system.

Crossing, water: The crossing by an onshore pipeline of a bay, lake, river, or major stream.

Current Density: The current to or from a unit area of an electrode surface.

Current Interrupter: A device that interrupts CP current.

D

Defect: A physically examined anomaly with dimensions or characteristics that exceed acceptable limits.

Depth of Cover (DOC): The burial depth from the ground directly above the pipeline to the top of the pipe.

Depolarization: The removal of factors resisting the current in an electrochemical cell. For the purposes of this standard, depolarization refers to a reduction in the level of protection due to a reduction or elimination of cathodic protection current.

Depolarized Close-Interval Potential Inspection: A CIS performed after influencing CP current sources have been turned off for a sufficient duration of time for depolarization to have occurred. This is often called a native-state CIS if it is performed prior to the initial application of CP.

Differential Global Positioning System (DGPS): Global Positioning System inspection using differential error correction in order to obtain more accurate positioning.

Direct Current Voltage Gradient (DCVG) Inspection: A method of measuring the change in the electrical voltage gradient in the soil along and around the pipeline to locate coating holidays.

Disbonded Coating: Any loss of adhesion between the protective coating and a pipe surface as a result of adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating holiday.

Downstream: In the direction of flow.

Drop-Cell Inspection: CIS of conventional submerged vertical riser.

Duty Cycle: The ratio of the duration CP current is applied to the duration CP current is interrupted.

Dynamic Stray Current: Stray current with changing amplitude and/or geographical path.

E

ECDA: The external corrosion direct assessment process as defined in this standard.

Electrical Connection: Point at which the structure is metallically connected to the measurement circuit.

Electrode: A conductor used to establish contact with an electrolyte and through which current is transferred to or from an electrolyte.

Electrolyte: A chemical substance containing ions that migrate in an electric field. For the purpose of this standard, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic piping system, including the moisture and other chemicals contained therein.

External Corrosion Direct Assessment (ECDA): A four step process that combines pre-assessment, indirect inspections, direct examinations, and post assessment to evaluate the impact of external corrosion on the integrity of a pipeline.

F

Far-Ground (FG) Potential: A structure-to-electrolyte potential measured directly over the pipeline, away from the electrical connection to the pipeline.

Fast-Cycle Interruption: An interruption cycle in which the 'OFF' cycle is less than one second. Usually used so that both an 'ON'" and an instant-off structure-to-electrolyte potential can be measured at each measurement location.

Fast-Cycle Inspection: An interrupted CIS using fast-cycle interruption.

Field Comments: Comments entered by the inspection personnel during the CIS.

Field Plots: CIS graphs generated during the inspection.

Flag: A pin flag, or the interval that the flag represents, generally 30 m (100 ft).

Footer Information: Set of comments, measurements, and other information entered at the end of an inspection run.

Foreign Structure: Any metallic structure that is not intended as a part of a system under CP.

G

Galvanic Anode: A metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the electron source in one type of CP.

GIS: Global Information System - A database where information is stored with spatial coordinates to facilitate mapping and surveying.

Global Positioning System (GPS): The navigational system utilizing satellite technology to provide a user a position on the earth's surface.

H

Header Information: Set of comments, measurements, and other information entered at the start of an inspection run.

High-Vapor-Pressure (HVP) pipeline system: A pipeline system conveying hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapor pressure greater than 110 kPa absolute at 38 °C, as determined using the Reid method (see ASTM D 323).

Holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment.

Hot-Spot Inspection: A cell-to-cell surface potential gradient inspection consisting of a series of potential gradients measured along the pipeline, often used on pipelines that are not electrically continuous or on bare or ineffectively coated pipelines in order to detect the probable current discharge (anodic) areas along a pipeline. Where the pipeline is electrically continuous, a close-interval inspection and lateral potentials will also detect areas of probable current discharge (anodic areas).

Hydrostatic Testing: Proof testing of sections of a pipeline by filling the line with water and pressurizing it until the nominal hoop stresses in the pipe reach a specified value.

I

Imperfection: An anomaly with characteristics that do not exceed acceptable limits.

Impressed Current: An electric current supplied by a device employing a power source that is external to the electrode system. (An example is direct current for CP.)

In-Line Inspection (ILI): The inspection of a steel pipeline using an electronic instrument or tool that travels along the interior of the pipeline.

Indication: Any deviation from the norm as measured by an indirect inspection tool such as CIS. An indication may be further classified or characterized as an anomaly or imperfection.

Input Impedance: The equivalent electrical impedance of a voltmeter's internal circuitry in the measurement circuit.

Input Resistance: The equivalent electrical resistance of a voltmeter's internal circuitry in the measurement circuit.

Instant-Off Potential: The polarized half-cell potential of an electrode taken immediately after the CP current is stopped, which closely approximates the potential without IR drop (i.e., the polarized potential) when the current was on.

Interference: Any electrical disturbance on a metallic structure as a result of stray current.

Interference Bond: An intentional metallic connection, between metallic systems in contact with a common electrolyte, designed to control electrical current interchange between the systems.

Interrupted Close-Interval Potential Inspection (On/Off Inspection): A series of structure-to-electrolyte potentials taken along a pipeline, with influencing CP current sources switched using equipment designed to interrupt the CP current briefly.

Interruption Cycle: Duration of current interruption in the 'ON' and 'OFF' cycle.

IR Drop: The voltage across a resistance in accordance with Ohm's Law.

J K L

Lateral Potentials: Structure-to-electrolyte potentials offset to each side of the pipeline, typically at a distance of approximately two and one-half times the pipe depth.

Line Current: The direct current flowing on a pipeline.

Long-Line Current: Current through the earth between an anodic and a cathodic area that returns along an underground metallic structure.

Long-Line Current Voltage Drop Error: The voltage drop error in the instant-off potential caused by current in the soil due to potential gradients along the pipe surface.

Low-vapor-pressure (LVP) pipeline system: A pipeline system conveying:

- a) Hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapor pressure of 110 kPa absolute or less at 38 °C, as determined using the Reid method (see ASTM D 323);
- b) Multiphase fluids; or
- c) Oilfield water.

M

Maximum Allowable Operating Pressure (MAOP): The maximum internal pressure permitted during the operation of a pipeline.

Metallic IR Drop: Component of IR drop that occurs in the metallic path of the measurement circuit, primarily in the pipeline, under normal conditions.

Microbiologically Influenced Corrosion (MIC): Localized corrosion resulting from the presence and activities of microorganisms, including bacteria and fungi.

N

NDE: Non-Destructive Evaluation: NDE is a wide group of analysis techniques used in science and industry to evaluate the properties of a material, component or system without causing damage. The terms Non-destructive testing (NDT), Non-destructive inspection (NDI), and Non-destructive examination (NDE) are also commonly used to describe this technology. Because NDT does not permanently alter the article being inspected, it is a highly valuable technique that can save both money and time in product evaluation, troubleshooting, and research.

Near-Ground (NG) Potential: A structure-to-electrolyte potential taken directly over the pipeline, at the spot of electrical connection.

O

'OFF' Cycle: The period of time CP current is interrupted during one cycle of interruption.

'OFF' Potential: See Instant-Off Potential.

'ON' Close-Interval Potential Inspection: A series of structure-to-electrolyte potentials taken along a pipeline with the CP current applied.

'ON' Cycle: The period of time CP current is applied during one cycle of interruption.

'ON' Potential: A potential measured with CP current applied.

Open-Circuit Potential: The potential of an electrode measured with respect to a reference electrode or another electrode in the absence of current.

P

Polarization: The change from the open-circuit potential as a result of current across the electrode/electrolyte interface.

Polarization Cell Replacement (PCR): Allows AC to Couple and flow to ground while simultaneously decoupling the DC so it remains on the pipeline.

Polarized Potential: The potential across the structure/electrolyte interface that is the sum of the corrosion potential and the cathodic polarization

Prioritization: The process of estimating the need to perform a direct examination at each indirect inspection indication based on current corrosion activity plus the extent and severity of prior corrosion.

Q R

Reference Electrode: An electrode whose open-circuit potential is constant under similar conditions of measurement. It is used for measuring the relative potentials of other electrodes. Examples include saturated copper/copper sulfate (CSE), saturated calomel (SCE), and silver/silver chloride (Ag/AgCl).

Remote Earth (also Electrically Remote): A location on the earth far enough from the affected structure that the soil potential gradients associated with currents entering the earth from the affected structure are insignificant.

ROW = Right-of-way: A right-of-way is legal land area designated for road, railway or pipelines, where the facility owner has a legal right-of-way.

Road: A generic term denoting a highway, road, or street.

S

Saturated: A solution obtained when a solvent (liquid) can dissolve no more of a solute (usually a solid) at a given temperature and pressure.

Scatter: Erroneous potentials usually caused by contact resistance.

Shielding: Preventing or diverting CP current from its natural path.

Shorted Pipeline Casing: A casing that is in direct metallic contact with the carrier pipe.

Side-Drain Potentials: Surface potential gradients measured between two reference electrodes, one located directly over the pipeline and the other offset to each side of the pipeline, typically at a distance of approximately two and one-half times the pipe depth.

Side-Drain Potential Inspection: A cell-to-cell surface potential gradient inspection consisting of a series of side-drain potentials measured along a pipeline.

Spiking: A momentary surging of potential that occurs on a pipeline when the protective current from an operating CP device is interrupted or applied.

Station Number: Distance information from a reference on the pipeline, used to locate a point on a pipeline.

Stray Current: Current through paths other than the intended circuit.

Stray-Current Corrosion: Corrosion resulting from current through paths other than the intended circuit, e.g., by any extraneous current in the earth.

Structure-to-Electrolyte Potential: The potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

Surface Potential Gradient: Change in the potential on the surface of the ground with respect to distance.

Surface Potential Gradient Inspection: A series of surface potential gradients measured along or normal (perpendicular) to a pipeline. Surface potential gradient inspections include DCVG, ACVG, hot-spot inspections, and side-drain inspections.

- **Inspection Direction:** The direction a CIS is conducted along a pipeline, usually expressed as up-station or down-station.
- **Inspection Interval:** The specified distance between potential measurements along the pipeline in a CIS.
- **Inspection Run:** The set of data associated with a single electrical connection to the structure, usually the measurements from one test lead to the next.
- **Inspection Wire:** Insulated wire, usually copper, used to connect inspection instrument to the pipeline during a CIS.

Synchronized Inspection: An interrupted CIS in which the CP current sources are all switched simultaneously.

T

Telluric Current: Current in the earth as a result of geomagnetic fluctuations.

Telluric Inspection: Inspection that is performed to correct for telluric currents.

Test Lead (also Test Station, Test Post): A wire or cable attached to a structure for electrical connection of inspection instrument to make CP potential or current measurements.

Trailing-Wire DCVG: A hybrid inspection that simultaneously measures the structure-to-electrolyte potentials and the potential difference between reference electrodes along the pipeline.

U

Upload: To send data from the field data acquisition system to a personal computer (PC).

Upstation: In the direction of decreasing station number or KP/MP.

Upstream: In the direction opposite to the direction of flow.

V

Voltage: An electromotive force or a difference in electrode potentials expressed in volts.

Voltage Drop: The voltage across a resistance according to Ohm's Law.

Voltmeter Accuracy: The capability of the instrument to faithfully indicate the value of the measured signal. This term is not related to resolution; however, it can never be better than the resolution of the instrument.

Voltmeter Resolution: The smallest amount of input signal change that the instrument can detect reliably.

W

Wire: A slender rod or filament of drawn metal. In practice, the term is also used for smaller-gauge conductors (No. 10 AWG or smaller).

Wire Counter: A device that measures inspection distance based on the length of spooled wire.

XYZ

XLI: external Line Inspection – XLI is a family of products designed for comprehensive External Line Inspection. It integrates geodetic line mapping (GPS Centerline) and external corrosion direct assessment (ECDA) indirect inspection techniques (IIT)

APPENDIX 5

FULL LIST OF INDICATIONS / DEFICIENCIES

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
1: Severe DC interference	0 to 538	-	-	-	-	**Scheduled**	**Severe DC interference detected with electropositive shifts higher than 60mV along this 538m stretch - Begin by upgrading priority at biggest coating indication to immediate - Proceed by upgrading other indications according to results of direct examination.**	48.0956622	-80.1801563
2: Minor DCVG	166.6	-1.270	46.2	1.2	20.4%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0967075	-80.1788642
3: Minor DCVG	177.0	-1.272	42.0	3.0	23.8%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0967919	-80.1788051
4: Minor DCVG	228.5	-1.296	39.2	0.7	32.0%	**Immediate**	**DE#1: Upgraded to "Immediate action required" due to the severe dc interference detected. DE results here will affect prioritization of all anomalies located between chainage 0 and 540 (Approx.)**	48.0972482	-80.1787766
5: Minor DCVG	246.4	-1.271	39.2	1.0	17.1%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0974091	-80.1787723
6: Minor ACCA	257.4	-1.267	39.9	3.2	0.0%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0975081	-80.1787685
7: Minor ACCA	273.5	-1.307	39.2	2.2	8.0%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0976524	-80.1787644
8: Minor DCVG	293.8	-1.265	39.2	1.1	15.1%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0978335	-80.1787492
9: Minor ACCA	302.5	-1.331	39.9	2.7	4.6%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0979044	-80.1786987
10: Minor ACCA	319.4	-1.284	35.0	3.8	4.8%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0979332	-80.1784894
11: Minor DCVG	377.7	-1.285	32.9	0.4	21.6%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.098055	-80.1777302
12: Moderate ACCA	435.1	-1.243	37.1	6.3	4.5%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0981782	-80.1769831
13: Minor DCVG	508.1	-1.170	40.6	0.4	16.4%	**Monitored**	May be upgraded depending on direct examination results of DE#1.	48.0983453	-80.1760389
14: Severe DCVG	538.3	-1.210	40.6	0.0	71.5%	**Immediate**	**DE#2: Severe DCVG indication and located in close proximity to region of severe DC interference.**	48.0984125	-80.1756487
15: Moderate ACVG	543.5	-1.125	54.6	0.0	7.5%	**Monitored**	Suitable for monitoring	48.0984181	-80.1755789
16: Minor DCVG	600.9	-1.167	50.4	0.3	29.4%	**Monitored**	Suitable for monitoring	48.0985418	-80.1748348
17: Minor DCVG	626.9	-1.250	51.8	0.3	26.4%	**Monitored**	Suitable for monitoring	48.0986052	-80.1744983

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
18: Minor DCVG	639.1	-1.221	49.0	0.2	32.6%	**Monitored**	Suitable for monitoring	48.0986264	-80.1743388
19: Minor DCVG	658.2	-1.215	51.1	0.1	29.1%	**Monitored**	Suitable for monitoring	48.0986697	-80.174092
20: Minor DCVG	690.3	-1.158	49.7	0.3	20.0%	**Monitored**	Suitable for monitoring	48.0987394	-80.1736769
21: Minor DCVG	728.7	-1.147	50.4	0.2	29.2%	**Monitored**	Suitable for monitoring	48.0988225	-80.1731766
22: Minor ACVG	774.8	-1.121	45.5	0.3	11.6%	**Monitored**	Suitable for monitoring	48.0989203	-80.1725765
23: Minor DCVG	790.4	-1.125	44.8	0.4	18.2%	**Monitored**	Suitable for monitoring	48.098953	-80.1723754
24: Minor DCVG	823.8	-1.078	44.8	1.4	25.2%	**Monitored**	Suitable for monitoring	48.099027	-80.1719426
25: Minor DCVG	832.2	-1.063	41.3	0.2	28.1%	**Monitored**	Suitable for monitoring	48.0990476	-80.1718344
26: Minor DCVG	848.0	-1.112	41.3	0.2	24.3%	**Monitored**	Suitable for monitoring	48.0990824	-80.1716303
27: Minor DCVG	860.2	-1.045	44.8	0.3	26.7%	**Monitored**	Suitable for monitoring	48.0991061	-80.1714704
28: Minor DCVG	878.6	-1.013	42.7	0.2	29.2%	**Monitored**	Suitable for monitoring	48.0991461	-80.1712318
29: Minor DCVG	921.4	-0.986	44.8	0.0	25.8%	**Monitored**	Suitable for monitoring	48.0992454	-80.1706822
30: Minor CIPS	951.9	-0.898	41.3	0.6	8.7%	**Monitored**	Suitable for monitoring	48.0993156	-80.1702887
31: Minor DCVG/Minor CIPS	975.6	-0.875	45.5	0.3	28.7%	**Monitored**	Suitable for monitoring	48.0993615	-80.1699813
32: Moderate ACCA / Severe CIPS	991.8	-0.574	49.0	7.4	2.2%	**Scheduled**	**Scheduled action required - Recommended for DE (#9)**	48.0993909	-80.1697683
33: Moderate ACCA / Minor CIPS	1008.9	-0.869	46.9	7.2	10.3%	**Monitored**	Suitable for monitoring	48.0994285	-80.169582
34: Minor DCVG	1129.0	-1.071	40.6	0.5	23.4%	**Monitored**	Suitable for monitoring	48.0996846	-80.1680399
35: Severe CIPS/Moderate DCVG	1171.3	-0.593	46.2	0.3	42.4%	**Immediate**	**DE#3: Upgraded to "Immidate action required" due to DCVG indication characteristics in combination with severe CIPS indication.**	48.0997917	-80.1675181
36: Minor DCVG	1198.3	-1.041	44.1	0.2	21.4%	**Monitored**	Suitable for monitoring	48.0998471	-80.1671671

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
37: Minor DCVG	1226.7	-1.296	44.8	0.1	19.8%	**Monitored**	Suitable for monitoring	48.0998931	-80.1667928
38: Minor DCVG	1297.6	-1.252	47.6	1.2	16.4%	**Monitored**	Suitable for monitoring	48.1000557	-80.165877
39: Minor DCVG	1359.3	-1.188	46.9	0.7	15.1%	**Monitored**	Suitable for monitoring	48.1001736	-80.1650903
40: Moderate ACVG	1376.8	-1.172	51.1	0.8	10.1%	**Monitored**	Suitable for monitoring	48.1002118	-80.1648629
41: Minor ACCA	1383.6	-1.166	49.7	1.9	14.3%	**Monitored**	Suitable for monitoring	48.1002317	-80.1647867
42: Minor ACCA	1415.6	-1.021	49.0	2.0	5.0%	**Monitored**	Suitable for monitoring	48.1002674	-80.1643652
43: Minor DCVG	1492.9	-0.956	49.7	0.0	15.5%	**Monitored**	Suitable for monitoring	48.1002074	-80.1633356
44: Minor ACCA	1527.5	-0.958	44.8	1.7	3.4%	**Monitored**	Suitable for monitoring	48.1002152	-80.162879
45: Moderate CIPS/Minor DCVG	1545.9	-0.760	45.5	0.3	18.7%	**Monitored**	Suitable for monitoring	48.1002113	-80.1626562
46: Minor DCVG	1559.9	-0.928	46.9	0.5	18.9%	**Monitored**	Suitable for monitoring	48.1001897	-80.1624725
47: Moderate DCVG/Minor CIPS	1609.9	-0.820	48.3	0.5	38.1%	**Monitored**	May be upgraded depending on direct examination results of DE#3.	48.1001519	-80.1618059
48: Minor ACCA/Minor CPIPS	1665.4	-0.804	44.8	1.8	3.7%	**Monitored**	May be upgraded depending on direct examination results of DE#3.	48.1000958	-80.1610728
49: Severe CIPS	1682.1	-0.563	48.3	0.5	8.0%	**Scheduled**	**Scheduled action required - May be upgraded depending on direct examination results of DE#3.**	48.1000751	-80.1608515
50: Severe CIPS/Moderate DCVG	1694.7	-0.600	50.4	0.6	46.6%	**Immediate**	**DE#4: Upgraded to "Immediate action required" due to proximity to region with significant prior corrosion.**	48.1000674	-80.1606817
51: Moderate CIPS/Minor DCVG	1745.2	-0.797	45.5	0.1	22.4%	**Monitored**	May be upgraded depending on direct examination results of DE#3.	48.1000933	-80.1600316
52: Moderate DCVG	1798.4	-0.928	44.8	0.1	41.4%	**Monitored**	Suitable for monitoring	48.1000499	-80.1593346
53: Moderate DCVG/Minor CIPS	1817.5	-0.854	45.5	0.5	43.5%	**Monitored**	Suitable for monitoring	48.1000427	-80.159084
54: Moderate DCVG	1860.1	-1.188	45.5	0.2	53.0%	**Monitored**	Suitable for monitoring	48.1000099	-80.1585154
55: Minor DCVG	1889.3	-1.154	44.1	0.2	33.1%	**Monitored**	Suitable for monitoring	48.0999913	-80.1581271

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
56: Minor DCVG	1903.0	-1.152	45.5	0.3	20.4%	**Monitored**	Suitable for monitoring	48.0999851	-80.1579445
57: Minor DCVG	1919.3	-1.150	44.1	0.7	16.6%	**Monitored**	Suitable for monitoring	48.09999	-80.1577267
58: Moderate DCVG/Minor ACCA	1936.0	-1.157	46.2	3.6	36.3%	**Monitored**	Suitable for monitoring	48.1000263	-80.1575088
59: Moderate DCVG/Minor ACCA	1950.0	-1.151	50.4	3.2	45.0%	**Monitored**	Suitable for monitoring	48.1000648	-80.1573418
60: Minor ACCA	1958.5	-1.141	51.1	4.5	14.0%	**Monitored**	Suitable for monitoring	48.1000853	-80.1572309
61: Minor DCVG	1965.3	-1.136	51.8	1.7	19.5%	**Monitored**	Suitable for monitoring	48.1001019	-80.1571439
62: Minor DCVG	1990.5	-1.088	53.2	0.3	25.7%	**Monitored**	Suitable for monitoring	48.100164	-80.1568213
63: Moderate DCVG	2008.1	-1.088	54.6	1.3	58.6%	**Monitored**	Suitable for monitoring	48.1002095	-80.1565971
64: Moderate DCVG/Minor ACCA	2029.5	-1.085	54.6	2.4	35.5%	**Monitored**	Suitable for monitoring	48.1002625	-80.1563205
65: Moderate DCVG	2085.9	-0.988	56.7	1.4	42.7%	**Monitored**	Suitable for monitoring	48.1004035	-80.1555969
66: Minor CIPS	2099.5	-0.872	53.9	1.0	3.8%	**Monitored**	Suitable for monitoring	48.1004415	-80.1554264
67: Minor ACCA/Minor DCVG	2131.5	-0.888	53.2	2.8	20.6%	**Monitored**	Suitable for monitoring	48.1005241	-80.1550176
68: Moderate ACVG/Minor CIPS	2151.9	-0.856	59.5	1.3	7.8%	**Monitored**	Suitable for monitoring	48.100557	-80.1547498
69: Severe CIPS/Moderate ACVG	2177.2	-0.692	55.3	0.3	3.0%	**Scheduled**	**Scheduled action required**	48.1006255	-80.1544274
70: Severe CIPS/Moderate DCVG	2188.6	-0.680	53.9	1.5	35.2%	**Scheduled**	**Scheduled action required - Candidate for DE**	48.1006517	-80.1542793
71: Severe CIPS	2195.3	-0.581	53.9	1.0	8.5%	**Scheduled**	**Scheduled action required**	48.1006741	-80.1541956
72: Severe CIPS/Minor DCVG	2217.4	-0.674	56.0	1.0	20.0%	**Scheduled**	**Scheduled action required**	48.1007297	-80.1539122
73: Severe CIPS	2224.7	-0.495	54.6	0.5	1.6%	**Scheduled**	**Scheduled action required**	48.1007474	-80.1538169
74: Moderate DCVG/Minor ACCA	2246.5	-1.026	57.4	3.4	37.6%	**Monitored**	Suitable for monitoring	48.1008079	-80.15354

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
75: Moderate DCVG/Moderate CIPS	2259.0	-0.751	56.7	0.4	38.8%	**Monitored**	Suitable for monitoring	48.1008402	-80.1533805
76: Moderate CIPS/Minor ACCA	2272.2	-0.777	56.0	2.6	9.2%	**Monitored**	Suitable for monitoring	48.1008717	-80.1532105
77: Severe CIPS	2309.3	-0.639	58.8	0.5	4.0%	**Scheduled**	**Scheduled action required**	48.1009731	-80.1527369
78: Severe CIPS/Moderate DCVG	2330.2	-0.667	57.4	0.8	41.2%	**Immediate**	**DE#5: Upgraded to "Immediate action required" due to proximity to region with significant prior corrosion.**	48.1010268	-80.1524694
79: Moderate ACCA/Moderate CIPS	2346.4	-0.772	58.1	6.6	5.8%	**Monitored**	Suitable for monitoring	48.1010894	-80.1522731
80: Minor DCVG	2366.9	-0.920	60.9	1.0	26.6%	**Monitored**	Suitable for monitoring	48.1011921	-80.1520459
81: Minor DCVG	2389.3	-0.844	62.3	2.0	18.0%	**Monitored**	Suitable for monitoring	48.1013044	-80.1517975
82: Severe CIPS	2414.0	-0.647	51.1	0.0	12.3%	**Scheduled**	**Scheduled action required**	48.101419	-80.1515183
83: Moderate CIPS	2428.2	-0.756	49.0	0.0	11.0%	**Monitored**	Suitable for monitoring	48.1014857	-80.1513648
84: Shallow cover/Severe CIPS	2444.4	-0.676	45.5	0.3	9.6%	**Scheduled**	**Scheduled action required**	48.1015608	-80.1511853
85: Minor DCVG/Minor CIPS	2496.3	-0.892	51.8	0.0	20.7%	**Monitored**	Suitable for monitoring	48.1017987	-80.1505913
86: Moderate DCVG/MinorCIPS	2512.5	-0.896	47.6	0.6	35.7%	**Monitored**	Suitable for monitoring	48.1018627	-80.1503975
87: Minor ACCA	2608.0	-1.198	45.5	1.8	1.8%	**Monitored**	Suitable for monitoring	48.1023044	-80.1493077
88: Minor DCVG	2626.1	-1.098	44.8	0.6	21.9%	**Monitored**	Suitable for monitoring	48.1023712	-80.1490905
89: Minor ACCA	2642.6	-1.126	46.2	1.6	4.3%	**Monitored**	Suitable for monitoring	48.1024013	-80.1488758
90: Minor CIPS	2683.4	-0.856	50.4	0.3	17.2%	**Monitored**	Suitable for monitoring	48.1024038	-80.1483315
91: Moderate DCVG	2699.4	-0.930	46.9	0.3	35.3%	**Monitored**	Suitable for monitoring	48.1024212	-80.1481192
92: Minor ACCA	2715.0	-0.964	47.6	1.8	4.7%	**Monitored**	Suitable for monitoring	48.1024259	-80.1479111
93: Severe CIPS/Moderate DCVG	2801.3	-0.632	46.2	0.5	35.6%	**Scheduled**	**Scheduled action required - Recommended for DE (#10)**	48.1026128	-80.1467934

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
94: Moderate CIPS/Minor DCVG	2807.5	-0.750	47.6	0.5	25.7%	**Monitored**	Suitable for monitoring	48.1026233	-80.1467128
95: Minor DCVG/Minor CIPS	2833.3	-0.881	49.0	0.0	23.2%	**Monitored**	Suitable for monitoring	48.1026897	-80.1463832
96: Minor DCVG	2853.5	-0.820	46.9	0.3	17.7%	**Monitored**	Suitable for monitoring	48.1027324	-80.1461227
97: Moderate CIPS	2859.9	-0.793	47.6	0.2	2.7%	**Monitored**	Suitable for monitoring	48.1027361	-80.1460384
98: Minor ACCA	2871.7	-0.999	46.9	1.4	3.9%	**Monitored**	Suitable for monitoring	48.1027497	-80.1458873
99: Minor DCVG	2977.9	-0.965	49.7	0.8	31.5%	**Monitored**	Suitable for monitoring	48.1026636	-80.144495
100: Moderate CIPS/Minor DCVG	3031.0	-0.784	48.3	0.0	16.6%	**Monitored**	Suitable for monitoring	48.1026598	-80.1437933
101: Severe CIPS/Shallow cover	3054.6	-0.685	46.9	0.0	0.6%	**Scheduled**	**Scheduled action required**	48.1026487	-80.143477
102: Minor DCVG	3211.5	-1.075	46.9	1.0	16.4%	**Monitored**	Suitable for monitoring	48.1025366	-80.1413832
103: Minor DCVG	3232.1	-1.230	44.8	0.6	16.2%	**Monitored**	Suitable for monitoring	48.1025386	-80.1411068
104: Minor ACCA	3338.3	-1.025	46.9	2.1	1.7%	**Monitored**	Suitable for monitoring	48.1024763	-80.1396863
105: Moderate DCVG/Moderate CIPS	3413.2	-0.771	47.6	0.6	47.2%	**Immediate**	**DE#6: Upgraded to "Immediate action required" due to proximity to region with significant prior corrosion.**	48.1025625	-80.1387027
106: Severe CIPS/Minor DCVG	3433.0	-0.563	48.3	0.8	20.7%	**Scheduled**	**Scheduled action required**	48.102613	-80.1384496
107: Severe CIPS/Minor DCVG	3451.1	-0.687	48.3	0.4	18.8%	**Scheduled**	**Scheduled action required**	48.1026662	-80.1382203
108: Severe CIPS/Moderate DCVG	3494.8	-0.692	49.7	1.4	38.8%	**Scheduled**	**Scheduled action required - Candidate for DE**	48.1027937	-80.1376687
109: Moderate DCVG	3507.8	-0.858	46.9	2.2	41.2%	**Monitored**	Suitable for monitoring	48.1028206	-80.1374987
110: Minor DCVG	3517.6	-1.411	41.3	0.2	17.2%	**Monitored**	Suitable for monitoring	48.1028465	-80.1373737
111: Minor ACCA	3536.0	-1.162	48.3	1.9	0.0%	**Monitored**	Suitable for monitoring	48.102892	-80.1371375
112: Moderate CIPS	3574.0	-0.731	46.2	0.2	1.1%	**Monitored**	Suitable for monitoring	48.1029922	-80.1366499

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating ACVG (dB)	Coating Atten (mB/m)	Coating DCVG (%IR)	Prioritization	Comments	Latitude	Longitude
113: Moderate CIPS	3596.0	-0.716	46.9	0.0	0.6%	**Monitored**	Suitable for monitoring	48.1030517	-80.1363679
114: Severe CIPS	3612.8	-0.604	46.2	0.6	0.8%	**Scheduled**	**Scheduled action required**	48.1030979	-80.1361538
115: Moderate CIPS	3622.2	-0.705	46.2	0.8	15.1%	**Monitored**	Suitable for monitoring	48.1031264	-80.1360351
116: Minor CIPS	3649.7	-0.840	45.5	1.3	2.5%	**Monitored**	Suitable for monitoring	48.1031973	-80.1356838
117: Severe CIPS	3692.0	-0.654	45.5	0.2	8.9%	**Scheduled**	**Scheduled action required**	48.1033097	-80.1351417
118: Moderate CIPS	3721.0	-0.748	44.8	1.3	1.3%	**Monitored**	Suitable for monitoring	48.1033821	-80.1347697
119: Minor DCVG/Minor CIPS	3739.1	-0.803	46.2	1.1	19.5%	**Monitored**	Suitable for monitoring	48.1034208	-80.1345375
120: Minor CIPS	3829.9	-0.809	44.8	0.2	1.7%	**Monitored**	Suitable for monitoring	48.1036705	-80.1333811
121: Moderate CIPS	3843.6	-0.787	49.7	1.1	2.4%	**Monitored**	Suitable for monitoring	48.1037135	-80.1332095
122: Minor ACCA	3875.8	-1.204	42.0	1.5	1.2%	**Monitored**	Suitable for monitoring	48.1037916	-80.1327952
123: Minor ACCA	3935.9	-1.215	43.4	1.9	1.3%	**Monitored**	Suitable for monitoring	48.1039342	-80.1320178
124: Minor ACCA	3962.3	-1.219	42.0	1.6	2.7%	**Monitored**	Suitable for monitoring	48.104001	-80.1316784
125: Minor DCVG	4473.3	-1.204	50.4	0.0	20.6%	**Monitored**	Suitable for monitoring	48.1069892	-80.1281863
126: Moderate CIPS	4504.3	-0.794	46.9	0.5	4.6%	**Monitored**	Suitable for monitoring	48.1072603	-80.1281775
127: Minor DCVG/Suspected anode	4543.0	-1.285	45.5	0.4	22.9%	**Monitored**	Suitable for monitoring	48.1076079	-80.1281488
128: Moderate DCVG	4563.2	-1.284	45.5	1.4	49.1%	**Monitored**	Suitable for monitoring	48.1077877	-80.1281206
129: Minor DCVG/Minor CIPS	4600.2	-0.854	46.9	1.3	28.0%	**Monitored**	Suitable for monitoring	48.1080715	-80.1279146
130: Moderate CIPS	4610.0	-0.792	45.5	0.2	3.4%	**Monitored**	Suitable for monitoring	48.1081186	-80.1278059
131: Moderate DCVG/Suspected anode	4618.9	-1.266	46.2	0.2	49.0%	**Monitored**	Suitable for monitoring	48.1081534	-80.1276993

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
132: Moderate CIPS	4640.2	-0.797	44.8	0.1	2.7%	**Monitored**	Suitable for monitoring	48.108246	-80.1274507
133: Minor DCVG/Minor CIPS	4656.9	-0.880	46.2	0.6	19.8%	**Monitored**	Suitable for monitoring	48.1083207	-80.1272566
134: Minor DCVG	4668.1	-0.959	44.8	0.7	32.3%	**Monitored**	Suitable for monitoring	48.1083682	-80.1271254
135: Moderate CIPS/Minor DCVG	4683.8	-0.729	49.7	0.3	16.4%	**Monitored**	Suitable for monitoring	48.1084326	-80.1269477
136: Severe CIPS/Minor DCVG	4694.6	-0.619	46.9	0.4	16.9%	**Scheduled**	**Scheduled action required**	48.1084744	-80.1268181
137: Moderate CIPS/Minor DCVG	4710.7	-0.739	45.5	0.1	15.9%	**Monitored**	Suitable for monitoring	48.1085423	-80.1266267
138: Moderate DCVG/Suspected anode	4727.9	-0.931	46.2	0.3	56.0%	**Monitored**	Suitable for monitoring	48.1086095	-80.1264212
139: Moderate DCVG/Suspected anode	4744.5	-1.168	43.4	0.2	40.5%	**Monitored**	Suitable for monitoring	48.1086784	-80.1262244
140: Minor DCVG	4770.5	-1.274	43.4	0.2	20.8%	**Monitored**	Suitable for monitoring	48.1087942	-80.1259217
141: Minor DCVG/Minor CIPS	4819.7	-0.895	43.4	0.0	24.0%	**Monitored**	Suitable for monitoring	48.1090064	-80.1253481
142: Moderate DCVG	4873.3	-0.915	44.1	0.2	36.1%	**Monitored**	Suitable for monitoring	48.1092204	-80.1247072
143: Minor DCVG	4883.9	-0.924	45.5	0.4	17.1%	**Monitored**	Suitable for monitoring	48.1092666	-80.1245817
144: Moderate DCVG	4894.7	-0.918	46.9	0.1	39.3%	**Monitored**	Suitable for monitoring	48.1093103	-80.1244535
145: Minor DCVG	4909.4	-0.862	43.4	0.1	27.7%	**Monitored**	Suitable for monitoring	48.1093588	-80.1242718
146: Moderate CIPS/Minor DCVG	4924.4	-0.710	42.7	0.4	22.2%	**Monitored**	Suitable for monitoring	48.1094213	-80.1240925
147: Severe CIPS	4942.9	-0.690	43.4	0.5	10.4%	**Scheduled**	**Scheduled action required**	48.1095081	-80.1238843
148: Severe CIPS/Moderate DCVG	4952.0	-0.557	43.4	0.2	49.9%	**Scheduled**	**Scheduled action required - Candidate for DE**	48.1095514	-80.12378
149: Minor DCVG/Minor CIPS	4986.0	-0.816	44.1	0.3	30.1%	**Monitored**	Suitable for monitoring	48.1096954	-80.1233787
150: Minor DCVG	5051.6	-1.345	44.1	0.0	20.5%	**Monitored**	Suitable for monitoring	48.1099734	-80.1226108

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
151: Minor DCVG	5061.9	-1.360	43.4	0.3	18.5%	**Monitored**	Suitable for monitoring	48.1100232	-80.1224954
152: Moderate DCVG/Suspected anode	5131.6	-1.406	39.2	0.1	42.2%	**Monitored**	Suitable for monitoring	48.1103182	-80.1216739
153: Moderate DCVG/Suspected anode	5144.3	-1.386	41.3	0.2	44.1%	**Monitored**	Suitable for monitoring	48.1103737	-80.1215245
154: Minor DCVG	5165.2	-1.334	42.0	0.1	21.4%	**Monitored**	Suitable for monitoring	48.1104603	-80.1212766
155: Moderate DCVG	5210.0	-1.265	41.3	0.0	40.3%	**Monitored**	Suitable for monitoring	48.1106538	-80.120749
156: Minor DCVG	5224.3	-1.251	39.9	0.1	28.5%	**Monitored**	Suitable for monitoring	48.1107113	-80.1205787
157: Minor DCVG	5240.5	-1.206	38.5	0.4	21.2%	**Monitored**	Suitable for monitoring	48.1107795	-80.1203853
158: Minor DCVG	5316.4	-1.111	37.8	0.3	14.0%	**Monitored**	Suitable for monitoring	48.1111028	-80.1194914
159: Minor DCVG	5346.2	-1.099	39.2	0.5	27.6%	**Monitored**	Suitable for monitoring	48.1112306	-80.1191392
160: Minor DCVG	5451.7	-1.105	37.1	0.0	18.6%	**Monitored**	Suitable for monitoring	48.1116706	-80.1179295
161: Minor ACCA	5461.9	-0.951	37.1	1.8	9.8%	**Monitored**	Suitable for monitoring	48.111708	-80.1178045
162: Minor DCVG/Minor CIPS	5469.8	-0.858	35.0	0.1	20.4%	**Monitored**	Suitable for monitoring	48.111739	-80.1177105
163: Moderate CIPS/Minor DCVG	5477.4	-0.744	37.1	0.2	15.9%	**Monitored**	Suitable for monitoring	48.111776	-80.1176257
164: Minor DCVG/Minor CIPS	5485.9	-0.859	37.1	0.2	15.0%	**Monitored**	Suitable for monitoring	48.1118091	-80.1175223
165: Minor DCVG/Minor CIPS	5505.7	-0.895	36.4	0.0	21.9%	**Monitored**	Suitable for monitoring	48.1118969	-80.1172929
166: Minor DCVG	5538.8	-0.998	33.6	0.2	18.6%	**Monitored**	Suitable for monitoring	48.1120417	-80.1169054
167: Minor CIPS	5596.8	-0.887	35.0	0.0	3.8%	**Monitored**	Suitable for monitoring	48.1122861	-80.1162178
168: Minor DCVG	5708.5	-1.268	38.5	0.4	25.3%	**Monitored**	Suitable for monitoring	48.1127557	-80.1148961
169: Minor DCVG	5717.7	-1.248	38.5	0.4	25.1%	**Monitored**	Suitable for monitoring	48.1128012	-80.1147924

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
170: Minor CIPS	5746.9	-0.873	37.8	0.2	10.0%	**Monitored**	Suitable for monitoring	48.1129349	-80.1144586
171: Minor DCVG	5750.7	-0.978	36.4	0.1	22.9%	**Monitored**	Suitable for monitoring	48.1129501	-80.1144122
172: Severe CIPS/Minor DCVG	5785.2	-0.654	39.9	0.0	27.8%	**Scheduled**	**Scheduled action required**	48.113069	-80.1139874
173: Minor DCVG/Minor CIPS	5796.5	-0.835	39.9	0.2	5.6%	**Monitored**	Suitable for monitoring	48.1131194	-80.1138553
174: Minor DCVG/Minor CIPS	5825.6	-0.856	37.1	0.8	27.0%	**Monitored**	Suitable for monitoring	48.1132573	-80.1135248
175: Severe CIPS/Minor DCVG	5846.8	-0.543	40.6	0.5	27.2%	**Scheduled**	**Scheduled action required**	48.113369	-80.1132939
176: Severe CIPS	5898.4	-0.643	42.0	0.0	5.6%	**Scheduled**	**Scheduled action required**	48.1135824	-80.1126802
177: Minor DCVG	5954.7	-1.105	39.2	0.5	24.8%	**Monitored**	Suitable for monitoring	48.1137965	-80.1119997
178: Minor DCVG	5964.0	-1.219	35.7	0.5	22.6%	**Monitored**	Suitable for monitoring	48.1138371	-80.1118914
179: Severe CIPS	5998.0	-0.549	41.3	0.4	0.0%	**Scheduled**	**Scheduled action required**	48.1139768	-80.1114852
180: Minor DCVG	6012.8	-0.842	39.2	0.2	17.4%	**Monitored**	Suitable for monitoring	48.1140441	-80.1113165
181: Severe CIPS	6031.7	-0.560	43.4	1.3	14.9%	**Scheduled**	**Scheduled action required**	48.1141244	-80.1110961
182: Severe DCVG/Severe CIPS	6048.1	-0.645	43.4	0.8	67.6%	**Immediate**	**DE#7: "Immediate action required" due to severe indication by multiple inspection tools and possible DC intereference nearby. The two data anomalies were merged together as one dig site due to their close proximity to eachother.**	48.1141901	-80.1108978
183: Severe CIPS/DC interference	6053.7	-0.698	42.7	1.1	4.8%	**Immediate**		48.1142175	-80.1108357
184: Minor DCVG/DC interference	6067.2	-0.958	42.7	1.2	18.0%	**Monitored**	Suitable for monitoring	48.1142715	-80.1106732
185: Minor DCVG	6098.2	-1.263	39.2	0.1	28.8%	**Monitored**	Suitable for monitoring	48.1143415	-80.1102717
186: Moderate DCVG/Minor CIPS	6112.2	-0.893	41.3	0.0	38.6%	**Scheduled**	**Upgraded to "Scheduled action required" due to having multiple inspection tools showing indications, proximity to a region with significant prior corrosion and low potential shift.**	48.1143617	-80.1100863
187: Moderate CIPS	6159.9	-0.728	43.4	0.0	25.3%	**Scheduled**	**Upgraded to "Scheduled action required" due to having multiple inspection tools showing indications, proximity to a region with significant prior corrosion and possible DC interference nearby.**	48.1144425	-80.1094593

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
188: Minor CIPS	6171.6	-0.861	42.7	0.5	12.7%	**Monitored**	Suitable for monitoring	48.1144622	-80.109305
189: Moderate DCVG	6225.1	-0.980	35.0	0.1	35.1%	**Monitored**	Suitable for monitoring	48.1145557	-80.108602
190: Minor CIPS	6234.9	-0.831	43.4	0.0	9.6%	**Monitored**	Suitable for monitoring	48.1145784	-80.1084752
191: Minor DCVG	6239.1	-0.936	39.2	0.0	20.2%	**Monitored**	Suitable for monitoring	48.1145879	-80.1084211
192: Minor CIPS	6252.7	-0.890	39.9	0.1	1.1%	**Monitored**	Suitable for monitoring	48.1146051	-80.1082403
193: Minor DCVG	6260.9	-0.921	39.9	0.5	20.0%	**Monitored**	Suitable for monitoring	48.1146206	-80.1081332
194: Minor CIPS	6281.0	-0.889	41.3	0.3	12.2%	**Monitored**	Suitable for monitoring	48.1146541	-80.1078682
195: Minor DCVG	6316.7	-1.013	40.6	0.1	16.7%	**Monitored**	Suitable for monitoring	48.1147291	-80.1074019
196: Moderate DCVG	6349.8	-1.058	33.6	0.2	37.0%	**Monitored**	Suitable for monitoring	48.1147768	-80.106964
197: Severe DCVG	6376.1	-1.038	36.4	0.2	69.0%	**Scheduled**	**Scheduled action required**	48.1148212	-80.1066186
198: Moderate DCVG	6389.2	-1.055	32.2	0.3	54.2%	**Monitored**	Suitable for monitoring	48.1148416	-80.1064467
199: Severe CIPS/Minor DCVG	6425.4	-0.682	42.0	0.1	17.8%	**Scheduled**	**Scheduled action required**	48.1149104	-80.1059725
200: Minor DCVG	6445.2	-0.922	42.7	0.0	30.1%	**Monitored**	Suitable for monitoring	48.1149365	-80.1057109
201: Minor ACCA/Minor CIPS	6453.2	-0.865	41.3	2.1	4.0%	**Monitored**	Suitable for monitoring	48.1149454	-80.1056048
202: Moderate CIPS/Minor DCVG	6457.7	-0.764	43.4	1.0	24.1%	**Monitored**	Suitable for monitoring	48.1149511	-80.1055447
203: Moderate CIPS	6475.6	-0.709	45.5	0.1	22.4%	**Monitored**	Suitable for monitoring	48.1149774	-80.1053073
204: Moderate DCVG	6490.0	-1.140	44.8	0.5	35.1%	**Monitored**	Suitable for monitoring	48.1150049	-80.1051196
205: Moderate ACCA	6511.3	-1.215	44.8	5.0	7.7%	**Monitored**	Suitable for monitoring	48.1150423	-80.1048408
206: Minor DCVG	6562.1	-0.995	39.2	0.3	15.2%	**Monitored**	Suitable for monitoring	48.11513	-80.1041731

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating ACVG (dB)	Coating Atten (mB/m)	Coating DCVG (%IR)	Prioritization	Comments	Latitude	Longitude
207: Minor DCVG	6574.6	-1.061	37.1	0.2	16.4%	**Monitored**	Suitable for monitoring	48.115154	-80.1040089
208: Minor DCVG	6592.8	-0.923	39.9	0.2	15.2%	**Monitored**	Suitable for monitoring	48.1151843	-80.1037688
209: Minor DCVG	6622.5	-1.085	35.0	0.4	30.7%	**Monitored**	Suitable for monitoring	48.1152377	-80.1033788
210: Moderate DCVG	6634.4	-0.962	37.1	0.1	41.4%	**Monitored**	Suitable for monitoring	48.1152513	-80.1032205
211: Moderate CIPS	6642.5	-0.715	41.3	0.4	28.2%	**Monitored**	Suitable for monitoring	48.1152723	-80.103116
212: Minor DCVG	6662.2	-1.038	42.7	0.4	22.2%	**Monitored**	Suitable for monitoring	48.1153036	-80.1028579
213: Minor DCVG	6712.4	-1.045	38.5	0.5	28.2%	**Monitored**	Suitable for monitoring	48.1153956	-80.102204
214: Minor DCVG/Minor CIPS	6759.2	-0.853	35.7	0.1	28.8%	**Monitored**	Suitable for monitoring	48.1154709	-80.1015876
215: Minor DCVG/Minor CIPS	6775.7	-0.861	36.4	0.0	21.5%	**Monitored**	Suitable for monitoring	48.1155011	-80.1013714
216: Minor DCVG/Minor CIPS	6788.0	-0.891	30.8	0.1	22.7%	**Monitored**	Suitable for monitoring	48.1155202	-80.1012092
217: Moderate DCVG/Moderate CIPS	6802.1	-0.757	32.2	0.8	35.7%	**Scheduled**	**Upgraded to "Schedule action required" due to multiple inspection tools showing moderate indications coupled with proximity to regions with significant prior corrosion - Candidate for DE.**	48.115544	-80.101023
218: Moderate DCVG/Minor CIPS	6814.6	-0.817	28.0	0.3	39.1%	**Monitored**	Suitable for monitoring	48.1155624	-80.1008573
219: Minor DCVG/Minor CIPS	6836.3	-0.887	35.7	0.8	32.4%	**Monitored**	Suitable for monitoring	48.1155984	-80.1005718
220: Minor DCVG/Minor CIPS	6846.1	-0.880	35.0	0.7	27.7%	**Monitored**	Suitable for monitoring	48.1156222	-80.1004451
221: Moderate DCVG/Moderate CIPS	6865.1	-0.780	33.6	0.6	35.6%	**Scheduled**	**Upgraded to "Schedule action required" due to multiple inspection tools showing moderate indications coupled with proximity to regions with significant prior corrosion - Candidate for DE.**	48.1156534	-80.1001978
222: Severe CIPS/Moderate DCVG	6883.2	-0.493	35.7	0.3	48.2%	**Immediate**	**DE#8: Upgraded to "Immediate action required" due to proximity to region with significant prior corrosion.**	48.1156866	-80.0999603
223: Moderate DCVG	6912.0	-1.113	35.0	0.4	58.8%	**Monitored**	Suitable for monitoring	48.1157401	-80.0995846

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating ACVG (dB)	Coating Atten (mB/m)	Coating DCVG (%IR)	Prioritization	Comments	Latitude	Longitude
224: Minor CIPS/Minor DCVG	6919.2	-0.809	32.9	0.1	30.2%	**Monitored**	Suitable for monitoring	48.1157574	-80.099491
225: Minor ACCA	7048.3	-1.155	44.8	2.9	2.8%	**Monitored**	Suitable for monitoring	48.1163848	-80.0980491
226: Moderate DCVG	7244.9	-0.942	38.5	0.0	42.2%	**Monitored**	Suitable for monitoring	48.1173818	-80.0958876
227: Minor CIPS	7250.2	-0.867	35.7	0.3	1.7%	**Monitored**	Suitable for monitoring	48.1174093	-80.0958304
228: Minor DCVG	7257.9	-1.099	35.7	0.5	24.7%	**Monitored**	Suitable for monitoring	48.1174464	-80.0957433
229: Minor DCVG	7277.4	-1.207	30.8	0.3	31.9%	**Monitored**	Suitable for monitoring	48.1175474	-80.095532
230: Moderate DCVG	7315.3	-1.165	35.0	0.2	43.1%	**Monitored**	Suitable for monitoring	48.1177379	-80.095112
231: Moderate CIPS	7331.2	-0.757	35.7	0.0	8.8%	**Scheduled**	**Upgraded to "Scheduled action required" due to proximity to region with significant prior corrosion.**	48.1178091	-80.0949399
232: Moderate DCVG	7361.8	-1.417	40.6	0.0	52.5%	**Monitored**	Suitable for monitoring/Supsected anode	48.1179624	-80.0946096
233: Moderate DCVG	7389.4	-1.041	33.6	0.0	58.5%	**Monitored**	Suitable for monitoring	48.1180755	-80.0942823
234: Severe CIPS/Minor DCVG	7419.2	-0.590	38.5	0.2	23.9%	**Scheduled**	**Scheduled action required**	48.1182622	-80.0940146
235: Severe CIPS/Moderate DCVG	7449.2	-0.698	40.6	0.2	39.3%	**Scheduled**	**Scheduled action required**	48.1183699	-80.0936511
236: Severe CIPS/Moderate DCVG	7462.0	-0.666	39.9	0.0	35.1%	**Scheduled**	**Scheduled action required**	48.1184338	-80.0935075
237: Minor DCVG	7499.8	-1.148	35.0	0.2	24.1%	**Monitored**	Suitable for monitoring	48.1186532	-80.0931249
238: Minor DCVG	7538.1	-0.987	38.5	0.1	26.7%	**Monitored**	Suitable for monitoring	48.1188501	-80.0927063
239: Moderate DCVG	7590.3	-1.028	42.7	0.2	57.1%	**Monitored**	Suitable for monitoring	48.1191158	-80.0921314
240: Minor DCVG	7610.2	-1.154	42.0	0.4	17.7%	**Monitored**	Suitable for monitoring	48.1191513	-80.0918824
241: Minor DCVG	7635.8	-1.351	43.4	0.7	15.4%	**Monitored**	Suitable for monitoring	48.1192686	-80.0915897
242: Severe CIPS/Moderate DCVG	7665.9	-0.660	46.2	0.6	58.9%	**Scheduled**	**Scheduled action required - Recommended for DE (#11)**	48.1194118	-80.0912506

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
243: Severe CIPS/Moderate DCVG	7681.5	-0.640	44.8	1.3	41.9%	**Scheduled**	**Scheduled action required**	48.1194824	-80.0910769
244: Minor ACCA	7708.2	-1.082	50.4	3.3	0.7%	**Monitored**	Suitable for monitoring	48.1196582	-80.0908486
245: Minor DCVG	7716.4	-1.069	49.0	0.0	17.1%	**Monitored**	Suitable for monitoring	48.119713	-80.090776
246: Moderate ACCA	8331.3	-1.321	45.5	6.7	3.0%	**Monitored**	Suitable for monitoring	48.1228366	-80.0839757
247: Minor ACCA	8389.6	-1.324	47.6	1.5	1.7%	**Monitored**	Suitable for monitoring	48.1231356	-80.0833337
248: Minor DCVG	8411.3	-1.389	50.4	0.8	16.0%	**Monitored**	Suitable for monitoring	48.1232422	-80.0830904
249: Minor ACCA	8436.9	-1.273	56.7	1.8	0.0%	**Monitored**	Suitable for monitoring	48.1233783	-80.0828145
250: Minor ACCA	8464.2	-1.243	49.0	1.9	1.6%	**Monitored**	Suitable for monitoring	48.1235186	-80.0825168
251: Minor ACCA	8480.3	-1.254	49.7	1.9	0.9%	**Monitored**	Suitable for monitoring	48.1235979	-80.0823364
252: Minor ACCA	8503.6	-1.242	49.7	1.6	1.9%	**Monitored**	Suitable for monitoring	48.1237115	-80.0820729
253: Minor DCVG	8554.4	-1.072	49.0	1.2	16.5%	**Monitored**	Suitable for monitoring	48.1239665	-80.0815092
254: Minor CIPS	8577.9	-0.865	46.2	0.5	0.7%	**Monitored**	Suitable for monitoring	48.1241081	-80.081283
255: Moderate CIPS/Moderate DCVG	8603.7	-0.776	49.0	0.9	37.9%	**Monitored**	Suitable for monitoring	48.1242694	-80.0810363
256: Minor CIPS	8616.6	-0.800	46.9	0.4	3.2%	**Monitored**	Suitable for monitoring	48.1243482	-80.0809106
257: Severe CIPS/Minor DCVG	8648.0	-0.692	48.3	0.1	16.6%	**Scheduled**	**Upgraded to "Scheduled action required" due to severe CIPS indication coupled with a coating anomaly indication.**	48.1245225	-80.080582
258: Severe CIPS	8657.6	-0.587	47.6	0.2	2.4%	**Scheduled**	**Scheduled action required**	48.1245772	-80.0804821
259: Moderate CIPS	8670.5	-0.743	49.0	1.3	12.7%	**Monitored**	Suitable for monitoring	48.1246503	-80.0803476
260: Moderate DCVG	8759.6	-1.089	52.5	0.3	35.1%	**Monitored**	Suitable for monitoring	48.125147	-80.0794098
261: Minor CIPS	8784.3	-0.818	52.5	0.4	10.7%	**Monitored**	Suitable for monitoring	48.1252882	-80.0791566

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating ACVG (dB)	Coating Atten (mB/m)	Coating DCVG (%IR)	Prioritization	Comments	Latitude	Longitude
262: Severe CIPS/Moderate DCVG	8828.9	-0.458	46.9	0.9	36.5%	**Scheduled**	**Scheduled action required - Recommended for DE (#12)**	48.1254936	-80.078647
263: Minor ACCA	8863.4	-1.021	49.7	1.7	2.7%	**Monitored**	Suitable for monitoring	48.1257362	-80.0783665
264: Minor DCVG	8916.8	-1.234	54.6	0.1	16.3%	**Monitored**	Suitable for monitoring	48.1260497	-80.0778332
265: Minor ACCA	9004.5	-1.252	54.6	1.5	3.8%	**Monitored**	Suitable for monitoring	48.1265409	-80.0769124
266: Moderate ACCA	9182.3	-1.188	56.7	6.2	3.7%	**Monitored**	Suitable for monitoring	48.1274836	-80.0750999
267: Moderate ACCA	9197.9	-1.257	55.3	5.9	3.3%	**Monitored**	Suitable for monitoring	48.1274448	-80.0749026
268: Minor DCVG	9230.4	-1.381	60.9	0.2	18.2%	**Monitored**	Suitable for monitoring	48.127348	-80.0744999
269: Minor ACCA	9256.8	-1.365	54.6	4.5	7.4%	**Monitored**	Suitable for monitoring	48.1272533	-80.0741756
270: Minor ACCA	9338.2	-1.438	57.4	1.6	0.5%	**Monitored**	Suitable for monitoring	48.1275897	-80.0733159
271: Minor DCVG	9371.9	-1.369	51.8	0.1	15.1%	**Monitored**	Suitable for monitoring	48.1277699	-80.0729534
272: Minor DCVG	9393.2	-1.458	49.7	0.2	20.8%	**Monitored**	Suitable for monitoring	48.1278728	-80.0727118
273: Moderate DCVG	9406.2	-1.475	49.0	0.2	42.6%	**Monitored**	Suitable for monitoring	48.1279385	-80.0725679
274: Minor DCVG	9490.6	-1.400	48.3	0.1	18.2%	**Monitored**	Suitable for monitoring	48.1283692	-80.0716403
275: Minor DCVG	9523.6	-1.391	49.0	0.1	27.9%	**Monitored**	Suitable for monitoring	48.1285438	-80.0712818
276: Minor DCVG	9543.5	-1.367	49.7	0.1	15.7%	**Monitored**	Suitable for monitoring	48.1286415	-80.0710581
277: Minor DCVG	9605.9	-1.395	50.4	0.1	16.6%	**Monitored**	Suitable for monitoring	48.1289503	-80.0703587
278: Moderate DCVG	9619.6	-1.387	51.8	0.0	45.3%	**Monitored**	Suitable for monitoring	48.1290202	-80.0702066
279: Minor DCVG	9669.3	-1.453	51.8	0.0	18.7%	**Monitored**	Suitable for monitoring	48.1292746	-80.0696594
280: Minor DCVG	9689.1	-1.367	50.4	0.3	19.8%	**Monitored**	Suitable for monitoring	48.1293685	-80.0694331

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
281: Minor DCVG	9832.7	-1.374	49.7	0.1	31.8%	**Monitored**	Suitable for monitoring	48.1299643	-80.067727
282: Minor DCVG	9841.1	-1.359	49.7	0.2	26.9%	**Monitored**	Suitable for monitoring	48.1300019	-80.0676289
283: Minor DCVG	9900.5	-1.459	45.5	0.2	32.3%	**Monitored**	Suitable for monitoring	48.1302554	-80.066928
284: Minor DCVG	9914.2	-1.485	46.2	0.4	17.2%	**Monitored**	Suitable for monitoring	48.1303108	-80.066763
285: Minor DCVG	10020.2	-1.509	50.4	0.1	23.0%	**Monitored**	Suitable for monitoring	48.130748	-80.0655028
286: Moderate DCVG	10041.2	-1.533	49.0	0.4	35.6%	**Scheduled**	**Upgraded to "Scheduled action required" due to proximity to region with significant prior corrosion.**	48.1308385	-80.0652558
287: Moderate DCVG	10106.1	-1.534	46.2	0.0	43.2%	**Scheduled**	**Upgraded to "Scheduled action required" due to proximity to region with significant prior corrosion.**	48.131117	-80.0644938
288: Minor DCVG	10119.6	-1.528	46.2	0.0	19.3%	**Monitored**	Suitable for monitoring	48.1311704	-80.0643312
289: Minor DCVG	10150.6	-1.561	46.2	1.2	16.3%	**Monitored**	Suitable for monitoring	48.1312959	-80.0639593
290: Minor ACCA	10172.7	-1.555	44.1	2.4	1.8%	**Monitored**	Suitable for monitoring	48.1313864	-80.0636962
291: Minor DCVG	10236.5	-1.400	43.4	0.2	21.6%	**Monitored**	Suitable for monitoring	48.1316472	-80.0629337
292: Minor DCVG/Archer Dr.	10325.0	-1.367	40.6	0.0	28.5%	**Monitored**	Suitable for monitoring	48.132014	-80.0618818
293: Moderate DCVG	10381.0	-1.148	41.3	0.3	41.3%	**Monitored**	Suitable for monitoring	48.132205	-80.0611935
294: Minor DCVG	10403.2	-1.151	40.6	1.0	24.2%	**Monitored**	Suitable for monitoring	48.132299	-80.0609321
295: Minor DCVG	10429.3	-1.196	39.9	0.3	28.1%	**Monitored**	Suitable for monitoring	48.1324297	-80.0606443
296: Moderate DCVG	10452.9	-1.221	42.0	0.3	51.7%	**Monitored**	Suitable for monitoring	48.1325285	-80.0603695
297: Moderate DCVG	10483.7	-1.246	40.6	0.0	35.2%	**Monitored**	Suitable for monitoring	48.1326687	-80.0600138
298: Minor DCVG	10503.3	-1.277	40.6	0.2	30.0%	**Monitored**	Suitable for monitoring	48.1327496	-80.0597799
299: Minor DCVG	10515.6	-1.290	39.9	0.2	21.0%	**Monitored**	Suitable for monitoring	48.1328029	-80.0596359

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
300: Minor DCVG	10539.4	-1.184	45.5	1.1	19.7%	**Monitored**	Suitable for monitoring	48.1328936	-80.0593496
301: Minor DCVG	10570.3	-1.204	44.8	0.0	29.5%	**Monitored**	Suitable for monitoring	48.1330309	-80.0589922
302: Minor DCVG	10621.7	-1.238	43.4	0.1	17.6%	**Monitored**	Suitable for monitoring	48.1332438	-80.0583801
303: Moderate DCVG	10680.0	-1.287	44.8	0.1	35.5%	**Monitored**	Suitable for monitoring	48.1334876	-80.0576879
304: Moderate DCVG	10691.5	-1.266	44.1	0.3	38.9%	**Monitored**	Suitable for monitoring	48.1335373	-80.0575523
305: Minor DCVG	10713.2	-1.281	44.1	0.1	34.5%	**Monitored**	Suitable for monitoring	48.1336281	-80.0572947
306: Moderate DCVG	10741.2	-1.289	42.7	0.1	48.5%	**Monitored**	Suitable for monitoring	48.1337414	-80.0569588
307: Moderate DCVG/Moderate CIPS	10773.5	-0.794	44.8	0.2	52.5%	**Monitored**	Suitable for monitoring	48.1338755	-80.0565746
308: Severe CIPS	10783.9	-0.657	44.1	0.0	4.3%	**Scheduled**	**Scheduled action required**	48.1338968	-80.056443
309: Moderate DCVG	10808.6	-0.944	43.4	0.0	43.0%	**Monitored**	Suitable for monitoring	48.1340133	-80.0561655
310: Moderate DCVG	10831.1	-1.334	40.6	1.3	38.1%	**Monitored**	Suitable for monitoring	48.1341112	-80.0559006
311: Moderate DCVG	10848.4	-1.222	40.6	0.0	46.6%	**Monitored**	Suitable for monitoring	48.1341831	-80.0556953
312: Minor DCVG	10862.4	-1.146	42.7	0.2	18.0%	**Monitored**	Suitable for monitoring	48.1342404	-80.0555277
313: Minor DCVG	10879.5	-1.088	43.4	0.1	19.5%	**Monitored**	Suitable for monitoring	48.1343185	-80.055331
314: Moderate DCVG	10897.5	-1.094	44.1	0.2	44.5%	**Monitored**	Suitable for monitoring	48.1343934	-80.0551167
315: Moderate DCVG	10926.0	-0.999	44.1	0.0	44.6%	**Monitored**	Suitable for monitoring	48.1345107	-80.054777
316: Moderate DCVG	10942.0	-0.956	42.0	0.0	39.4%	**Monitored**	Suitable for monitoring	48.1345739	-80.054584
317: Moderate DCVG	10977.6	-1.020	43.4	0.0	51.4%	**Monitored**	Suitable for monitoring	48.1346992	-80.0541457
318: Minor DCVG	10986.1	-1.029	44.1	0.1	22.0%	**Monitored**	Suitable for monitoring	48.1347245	-80.0540392

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
319: Moderate DCVG	10995.5	-0.985	44.1	0.1	36.3%	**Monitored**	Suitable for monitoring	48.1347578	-80.0539222
320: Severe DCVG/Minor CIPS	11011.3	-0.822	42.7	3.3	67.7%	**Scheduled**	**Upgraded to "Scheduled action required due to all inspection tools showing anomaly indications and a severe DCVG indication.**	48.1348042	-80.0537242
321: Moderate DCVG	11029.0	-1.037	48.3	0.1	42.3%	**Monitored**	Suitable for monitoring	48.1348504	-80.0534981
322: Moderate DCVG	11053.6	-1.071	43.4	0.1	39.2%	**Monitored**	Suitable for monitoring	48.1349284	-80.0531904
323: Minor DCVG	11064.9	-1.187	42.7	0.4	24.4%	**Monitored**	Suitable for monitoring	48.1349745	-80.0530562
324: Moderate DCVG	11074.8	-1.098	43.4	0.8	46.0%	**Monitored**	Suitable for monitoring	48.135016	-80.0529376
325: Moderate DCVG	11102.4	-1.097	44.8	0.4	39.0%	**Monitored**	Suitable for monitoring	48.1351135	-80.0525986
326: Minor DCVG	11116.7	-1.130	42.0	0.2	17.1%	**Monitored**	Suitable for monitoring	48.1351612	-80.0524199
327: Minor DCVG	11149.3	-1.199	43.4	0.1	18.2%	**Monitored**	Suitable for monitoring	48.1352746	-80.0520155
328: Minor DCVG	11680.1	-1.373	49.7	0.5	20.5%	**Monitored**	Suitable for monitoring	48.1366772	-80.0454325
329: Minor ACCA/VALVE	11796.3	-1.379	51.8	4.8	6.5%	**Monitored**	Suitable for monitoring	48.1369141	-80.0439617
330: Minor DCVG	11805.6	-1.367	51.8	0.0	17.6%	**Monitored**	Suitable for monitoring	48.1369525	-80.0438514
331: Minor ACCA	11834.1	-1.370	50.4	1.7	0.5%	**Monitored**	Suitable for monitoring	48.1370593	-80.0435078
332: Minor DCVG	11857.1	-1.343	52.5	0.7	33.2%	**Monitored**	Suitable for monitoring	48.1371004	-80.0432113
333: Moderate DCVG	11865.2	-1.354	53.9	0.2	58.7%	**Monitored**	Suitable for monitoring	48.1371227	-80.0431076
334: Minor DCVG	11889.5	-1.345	52.5	0.3	22.2%	**Monitored**	Suitable for monitoring	48.137208	-80.0428078
335: Minor DCVG	11914.0	-1.370	53.9	0.3	23.8%	**Monitored**	Suitable for monitoring	48.1372951	-80.0425093
336: Minor DCVG	11925.5	-1.339	53.2	0.4	27.8%	**Monitored**	Suitable for monitoring	48.1373314	-80.0423662
337: Minor DCVG	11952.8	-1.310	55.3	0.2	26.3%	**Monitored**	Suitable for monitoring	48.1374257	-80.0420291

Anomaly label	Approx. Chainage (m)	InstantOFF (V)	Coating			Prioritization	Comments	Latitude	Longitude
			ACVG (dB)	Atten (mB/m)	DCVG (%IR)				
338: Minor DCVG	11966.1	-1.302	52.5	0.5	21.6%	**Monitored**	Suitable for monitoring	48.1374716	-80.0418645
339: Minor DCVG	12024.3	-1.312	53.9	0.8	19.7%	**Monitored**	Suitable for monitoring	48.1376623	-80.0411419
340: Minor DCVG	12066.0	-1.348	55.3	0.7	31.2%	**Monitored**	Suitable for monitoring	48.1377778	-80.0406098
341: Minor ACCA	12107.7	-1.266	56.7	1.7	13.5%	**Monitored**	Suitable for monitoring	48.1379307	-80.0401042
342: Moderate DCVG	12171.0	-1.308	63.7	1.0	53.3%	**Monitored**	Suitable for monitoring	48.1382495	-80.0394179
343: Minor DCVG	12216.4	-1.289	60.9	2.0	26.8%	**Monitored**	Suitable for monitoring	48.1385194	-80.0389641
344: Minor DCVG	12238.7	-1.267	61.6	1.4	16.5%	**Monitored**	Suitable for monitoring	48.1386747	-80.0387776
345: Minor ACCA	12258.8	-1.335	67.2	3.0	3.4%	**Monitored**	Suitable for monitoring	48.1388436	-80.0386996
346: Moderate DCVG	12295.7	-1.242	70.0	0.0	54.5%	**Monitored**	Suitable for monitoring	48.1391736	-80.0386904

PROJECT SCHEDULE

Phase	2021												2022												2022											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Environmental																																				
Archealogical Investigation/Species at Risk																																				
Geotechnical Assessment/Excess Soil Management																																				
Land & Land Rights																																				
Easement Field Staking																																				
Temporary Workspaces																																				
Temporary Land Use																																				
Engineering & Construction																																				
Engineering																																				
Procurement																																				
Permits																																				
Construction (Energization, abandonment, restoration, etc.)									Clearing																											

ALTERNATIVES AND PROJECT DESCRIPTION

Summary of Alternatives

1. This evidence sets out the process and criteria used to select the alternative that best mitigates the pipeline's integrity concern while continuing to serve the existing system demands.

2. When existing facilities have known integrity concerns, alternatives are generated to extend the useful life of the asset or replace the asset. All alternatives are given preliminary review for feasibility, and practicable ones are organized into a key alternatives list. Each alternative on the key alternatives list is further evaluated in detail to make a final recommendation.

3. Criteria for selecting the best alternative include, but are not limited to:
   - Economic feasibility
   - Construction feasibility
   - Capacity created
   - Reliability of supply
   - System integrity benefits

4. The Project is a like for like replacement. The rationale for the decision is to provide replacement capacity for the current Kirkland Lake Lateral pipeline while also providing reliability of supply for emergency and operational scenarios in summer and shoulder month conditions. The following alternatives were identified and assessed for the Project[1]:

[1] The NPV analysis of the alternatives listed below can be found at Exhibit C, Tab 1, Schedule 1, Attachment 1.

a) Replace the entire 12 km of NPS 4 Kirkland Lake Lateral pipeline with NPS 6 6,895 kPa MOP pipeline

Replace 12 km of NPS 4 6,895 kPa MOP pipeline with 12 km of NPS 6 6,895 kPa MOP pipeline. The increased pipeline size was explored to accommodate potential future demand from the Municipality of Kirkland Lake and large volume customers. This option was deemed unnecessary as Enbridge Gas anticipates that it will be capable of meeting future demand growth using an NPS 4 6,895 kPa MOP pipeline. The cost of this alternative is $19.82 million.

b) Like-for-like replacement of 8 km of NPS 4 Kirkland Lake Lateral pipeline

Replace 8 km of NPS 4 6,895 kPa MOP pipeline with 8 km of NPS 4 6,895 kPa MOP pipeline. This provides replacement capacity for the Existing Line while also providing reliability of supply for emergency and operational scenarios in summer and shoulder month conditions. The total cost of this alternative is $16.8 million, making this the lowest-cost alternative.

c) Continue to maintain the existing 1958 NPS 4 Kirkland Lake Lateral and repair all required indications.

Continue to maintain the Existing Line and repair all required indications. Enbridge Gas performed an NPV analysis to compare the repair/maintain scenario against a full replacement scenario for both alternatives a) and b) above. As detailed at Exhibit C, Tab 1, Schedule 1, Attachment 1, NPV analysis indicated that the like-for-like replacement of 8 km of NPS 4 described in alternative b) was the preferred alternative.[2] The total cost of Alternative c) is $24.76 million.

[2] All costs set out at Exhibit C, Tab 1, Schedule 1, Attachment 1, Table 1, are direct capital and abandonment costs. Interest during construction and indirect overhead costs were not included.

Integrated Resource Planning

5. On July 22, 2021, the OEB issued its Decision and Order regarding Enbridge Gas's Integrated Resource Planning Framework Proposal (EB-2020-0091), including an Integrated Resource Planning Framework for Enbridge Gas ("IRP Framework")[3] which establishes policy guidance regarding the circumstances under which the Company should complete assessments of IRP alternatives ("IRPAs") in response to future identified needs and/or system constraints. The IRP Framework includes Binary Screening Criteria in order to focus IRPA assessments on identified needs and/or system constraints where there is reasonable expectation that an IRPA could efficiently and economically resolve the same.

6. Enbridge Gas has applied the Binary Screening Criteria to the identified integrity need/constraint driving the Project and has determined that it does not warrant further IRPA assessment, as the need/constraint occurs within the 3-year time horizon discussed as part of the "Timing" criterion:

> ii. Timing – If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need..[4]

7. As discussed at Exhibit B, Tab 1, Schedule 1, the Project is driven by a system integrity determination that replacement of the network elements mitigates the risks identified. The replacement of the Existing Line is necessary to serve downstream demands of customers in the Municipality of Kirkland Lake. While there is a parallel NPS 8 Kirkland Lake Loop pipeline in close proximity, that pipeline capacity on its own is not sufficient to serve to existing customers.

[3] EB-2020-0091, Decision and Order, July 22, 2021, Appendix A.
[4] Ibid., p.10

8. The Project involves construction of approximately 8 km of new NPS 4 pipeline with a wall thickness of 6.0 mm and grade 359 MPa (min). As the Project is driven by integrity concerns that must be addressed within three years, no demand side solution can resolve the integrity concerns.

9. As described in Exhibit B, Tab 1, Schedule 1, the current system includes two lines that run in parallel to the Existing Line for the majority of the distance from the TCPL supply station for approximately 12 km to the south west end of the Municipality of Kirkland Lake. As a result of the current system configuration, there are no available supply side alternatives that could be considered to reliably meet the customer demand in the towns of Kirkland Lake, Chaput Hughes, Swastika and the Macassa Mines.

<u>Proposed Facilities</u>

10. The proposed Project is a replacement of approximately 8 km of the existing 12 km of pipeline known as the NPS 4 Kirkland Lake Lateral pipeline. Based on the Integrity concerns detailed in Exhibit B, Tab 1, Schedule 1, the Existing Line has been deemed to carry an unacceptable operational risk and the Company has determined that replacing it is the most effective way of ensuring the continued safe and reliable delivery of natural gas services to customers.

11. The proposed design of the Project, including pipeline diameter and length, as well as the maximum operating pressure ("MOP") of the Project match the currently forecasted demand of the Existing Line.

12. For locations where the pipeline is being replaced, the Proposed Pipeline will be primarily installed using a lift and lay method, whereby the Existing Line will be removed and the same trench utilized for the install of the Proposed Pipeline,[5] with modifications made to the trench to ensure applicable installation and backfilling standards are met. Three separate sections along the route require horizontal

[5] The existing trench depth will be adjusted to meet the minimum requirement standard for pipe per CSA Z662-19, Section 12,4,7, Table 12.2.

directional drilling ("HDD"), to complete one watercourse crossing and two Ontario Northland Rail ("ONR") crossings.

13. The pipeline route will remain within Enbridge Gas's existing easements. Temporary Land Use ("TLU") is required along the easement corridor to accommodate construction space. Approximately 6 m North and an additional 2 m South is required from the Existing Line easement width for temporary land use purposes. For the pipelines abandoned in easement and where the lift and lay installation method is not utilized (replaced by directional drilling), easement agreements will be followed with respect to abandoning in place versus pipeline removal. In cases where easement direction is unclear (e.g. railway and river crossings), landowner input will be sought regarding treatment of abandonment of pipelines.

14. The Existing Line will be abandoned prior to the installation of the Proposed Pipeline. As the method of install is lift and lay, the Existing Line will need to be isolated and removed for the utilization of the trench. The Proposed Pipeline will be hydrostatically tested before energization.

15. Within the first replacement section only 1 station is connected to both the Proposed Pipeline and NPS 8 gas mains, the Swastika TBS (42501002 STN). However, following construction of the Proposed Pipeline only the NPS 4 (Proposed Pipeline) will remain connected. No other services or stations are connected on the remaining two sections of Existing Line.

16. The total estimated cost of the Project is approximately $20.7 million. This total includes indirect overheads. Without indirect overheads, loadings and IDC included, the total estimated cost is $16.8 million.

Timing

17. Construction of the Project will occur between February 2022 and December 2022. The Project will be placed into service in October 2022. The abandonment of the existing pipeline and site restoration would occur during November 2022.

NET PRESENT VALUE ASSESSMENT OF ALTERNATIVES

1. As discussed at Exhibits B and C, in support of the decision to proceed with the Project, Enbridge Gas conducted an analysis of the costs to repair/maintain the Existing Line compared to two replacement scenarios.

2. The analysis set out in Table 1 below assumes a 40-year time horizon, consistent with the approximate depreciable life of the Project. The costs related to repair and replacement scenarios were then discounted using the methodology prescribed by the OEB's E.B.O. 188 to arrive at a net present value for each.

3. For the Repair/Maintain Scenario analysis, Enbridge Gas assumed that 217 integrity digs (repairs or replacements) would have to be conducted over the next 40 years. It was also assumed that 35% of digs required repair and there would be one replacement required for the remaining life of the asset. Because the costs of repairs on the Existing Line typically range between $175,000 and $275,000 an average cost of $225,000 per repair was assumed. Costs for the replacements were based on costs for integrity digs involving repairs, and for the standard additional facilities that would need to be constructed in order to replace a segment of pipeline. These estimates are conservative as they do not take into account any location specific costs, which could be substantial for the Existing Line given its remote location. Because the costs for replacements on the Existing Line typically range between $337,500 and $412,500 an average cost of $375,000 per replacement was assumed. Also included in the Repair Scenario analysis were costs related to continued ECDAs every 5 years over the 40-year time horizon at a cost of $75,000 each.

4. Table 1 provides a summary of the results of the cost comparison analysis. The total cost of the Replacement Project is much lower than the cost of the Repair

Scenario. This is true for either replacement scenarios and when calculating net present value.

Table 1: NPV Analysis Results

$Millions	Replacement Scenarios		Repair Scenario
	Option A	Option B	Option C
Net Present Value	(18.2)	(15.5)	(26.4)

PROJECT COSTS AND ECONOMICS

Project Costs

1. The total estimated cost of the Project is $20.7 million as shown in Table 1 below. This cost includes: (i) materials; (ii) construction and labour; (iii) environmental protection measures; (iv) land acquisitions; (v) contingencies; (vi) interest during construction ("IDC"); and (vii) indirect overheads.

Table 1: Estimated Project Costs

Item No.	Description	Cost
1.0	Material Costs	$1,982,400
2.0	Labour Costs	$7,728,000
3.0	External Permitting, Land	$168,000
4.0	Outside Services	$3,074,400
5.0	Direct Overheads	$487,200
6.0	Contingency Costs	$3,360,000
7.0	**Project Cost**	**$16,800,000**
8.0	Indirect Overheads	$ 3,750,059
9.0	IDC	$116,281
10.0	**Total Project Costs**	**$20,666,340**

2. The cost estimates set out in Table 1 include a 25% contingency applied to all direct capital costs to reflect the preliminary design stage of this Project.

3. The cost estimate includes the cost of temporary working space easements that will be obtained where required and appropriate.

Project Economics

4. A Discounted Cash Flow report has not been completed as the Project is driven by integrity requirements.

EGI Asset Management Plan Addendum - 2022

September 30, 2021

Company: Enbridge Gas Inc.

Owned by: Asset Management Department

Controlled Location: Asset Management TeamSite

.

EGI Asset Management Plan Addendum - 2022

Page intentionally left blank.

Table of Contents

.

1 Overview

Enbridge Gas Inc. (EGI) filed an Asset Management Plan (AMP) for the period 2021-2025 in Phase 2 of EGI's 2021 rates filing (*EB-2020-0181*) at *Exhibit C, Tab 2, Schedule 1*.

This addendum aims to provide an update to the budget year 2022 for the AMP. This addendum is not a standalone document– it should be reviewed in conjunction with the previously filed AMP. As the identification of risks and opportunities and the execution of projects is dynamic, this document will only address changes impacting the 2022 budget year. Any changes beyond 2022 will be addressed in EGI's 2023-2032 AMP submission.

EGI's 2023-2032 AMP will:

- Outline the proposed core capital plan for EGI from 2023-2032.
- Identify IRP opportunities to meet needs out to 2032.
- Inform EGI's 2023 rates and 2024-2028 multiyear rate plan (which includes the 2024 rebasing year and 2025-2028 Incentive Rate Mechanism plan).

The assets for the two rate zones (EGD Rate Zone (RZ) and Union North and South Rate Zones) will be maintained separately for capital planning purposes for at least the duration of the deferred rebasing period.

The principles outlined in the AMP have not changed and the identified asset life cycle strategies have no material changes. Investment needs have emerged since the 2021-2025 AMP was filed in October 2020, and there have been new developments for existing projects; these changes have been reviewed to understand their impact on 2022. The process for updating the 2022 budget is detailed in **Section 2**, where the 2022 capital filed in the 2021-2025 AMP was used as a base and changes were identified by exception. The updated 2022 capital budget is presented by rate zone and asset class in **Table 1.0-1**.

Table 1.0-1: Summary of 2022 Capital Spend - EGD RZ, Union RZ and Total EGI (Includes Overheads)

2022 Budget	EGD Rate Zone	Union Rate Zone	Total EGI
Growth	146.0	122.6	268.6
Distribution Pipe	278.4	140.2	418.6
Distribution Stations	54.4	52.9	107.4
Utilization	50.1	60.4	110.5
Compression Stations	116.7	27.5	144.1
Liquified Natural Gas	0.0	0.5	0.5
Transmission Pipe & Underground Storage	13.0	118.2	131.3
Fleet & Equipment	17.3	14.8	32.0
Real Estate & Workplace Services	69.0	49.4	118.4
Technology & Information Systems	35.3	12.1	47.4
EA Fixed O/H	16.9	4.5	21.3
Total	797.0	603.1	1400.0

(costs expressed in millions of Canadian dollars)

Table 5.1-1 and **Table 5.2-1** in this Addendum note the variances that occurred in each of the asset classes from the 2022 forecast previously filed in the 2021-2025 AMP and the proposed 2022 capital budget. **Table 5.1-3** and **Table 5.2-3** show the 2021 forecast published in the 2021-2025 AMP compared to the proposed 2022 capital budget. Projects for which EGI will be seeking ICM treatment in 2022 are shown in **Table 5.1-2** and **Table 5.2-2**.

.

2 Budget Process for 2022

The process undertaken to review and prepare the 2022 budget ('budget refresh') for EGI used the capital investment specified in 2022 of the 5-year 2021-2025 AMP as a starting point. Updates were made on an exception basis. This process aligns with the annual asset management governance process used to manage the budget throughout the year.

Asset managers for each asset class identified changes to the capital requirements due to emerging needs, changing circumstances, potential for deferral, project execution risk and other drivers. All requests for emerging or revised projects were supported with clear purpose, need and timing. An overall review was undertaken to understand various project uncertainties and ensure that as much risk and opportunity is addressed as possible in the 2022 budget year within the constraints of the two rate zones.

The approval process for the 2022 budget included the following steps:

1. Asset Managers confirm investments submitted
2. Review by Asset Managers, Finance, and Subject Matter Advisors (to confirm portfolios for 2022 for each rate zone)
3. Review by Asset Management Steering Committee
4. Review and sign-off by Director, Integrity & Asset Management
5. Review and sign-off by VP Engineering & Storage Transmission Operations
6. Approval of 2022 Budget by EGI President
7. Approval of 2022 Budget by Enbridge Board

.

3 Strategic Priorities Updates

Enbridge's 2021 Enterprise Strategic Priorities (**Figure 3.0-1**) are defined to enable the organization to achieve its vision to be the leading energy delivery company in North America. Asset management actions and decisions align with these strategic priorities, contribute to Enbridge's success and support the company purpose of fueling people's quality of life, while maintaining the foundation of the business and positioning the company for future growth.

Figure 3.0-1: Enbridge Enterprise Strategic Priorities

4 2022 Asset Management Developments

Alignment of Risk Management to Asset Management Decision-Making

The Asset Management Core Process has been split into two processes – Risk Management and Asset Investment Planning and Management (AIPM). With the maturing of risk management and asset management practice at EGI, the risk management process functions independently of the AIPM process; it has become a formal input to AIPM when capital treatment is required to address an identified risk. This approach provides a decision support tool in addition to Copperleaf when determining risk treatment options and optimal investment timing.

Integrated Resource Planning (IRP)

In July 2021, the Ontario Energy Board released its Decision and Order in the Enbridge Gas Inc. Integrated Resource Planning Proposal (EB-2020-0091). This provides direction for EGI with respect to the scope, timing, stakeholder engagement, and cost recovery of non-facility alternatives.

Integrated Resource Planning represents a significant change to the facility planning that EGI has performed in the past and, as such, the Company is taking steps to develop processes, resources and capabilities to integrate these new requirements into its existing asset management and other processes.

EGI is beginning to consider IRP Assessment on certain projects, consistent with the guidance provided by the OEB in its Decision (EB-2020-0091). As noted in the IRP Decision, the potential of IRP alternatives to meet asset needs will be considered in the 2023-2032 AMP.

Integrity Management Program Enhancements

EGI continues to evolve its Integrity Management Program based upon industry best practices and incident learnings. EGI has developed a quantitative risk model to assess the risk for pipeline assets within the distribution system. This will be used to identify and prioritize assets that are approaching end of life and need to be replaced. Some transmission pipeline assets are already assessed using a quantitative risk model. That model has also been enhanced with the inclusion of additional hazards and consequences, as well as the introduction of Safety Targets that are aligned with EGI's risk evaluation criteria. In the coming months this model will be extended to cover all transmission pipe at EGI.

Advanced Metering Infrastructure (AMI)

EGI is considering the deployment of Advanced Metering Infrastructure (AMI), which would modernize customer meters and allow two-way communication. AMI is expected to:

- Reduce meter reading and call centre costs,
- Eliminate the need for estimated bills,
- Provide customers insight into their gas usage so they can make informed decisions.

With access to granular usage information, EGI gains needed insights into peak consumption and usage patterns. This will support EGI's implementation of an IRP program and may allow the deferral of reinforcement projects and promote carbon reduction. The new ultrasonic meters that could be deployed as part of an AMI program also offer enhanced safety features. An AMI pilot project is currently underway. The pilot will deliver evidence to support analysis on the of costs and benefits of implementing AMI.

Update on Administrative Space in a post COVID-19 Environment

EGI values in-person collaboration and intends to leverage the learnings acquired during the COVID-19 pandemic to pursue options supporting workplace flexibility. Working differently during the pandemic provided insights about the positive aspects and challenges experienced by employees and the business without day-to-day interaction. These lessons will guide EGI to provide the best possible working experience for employees, while continuing to serve our customers. EGI will evaluate options to leverage flexibility, while sustaining the importance of in person collaboration.

TIS Movement to Cloud Based Technology

As software license assets reach end of life, the option to renew these as on-premise licenses are no longer available in the market. In addition, to combat the increased risk on security and operations of the Company's physical technology assets, EGI is adopting a cloud-based infrastructure model which will provide the following:

- Reduce outages from hardware failures
- Reduce cyber-attack exposure
- Leverage a scalable core infrastructure
- Reduce technical debt and improve business reliability

.

These drivers result in higher O&M costs as spending shifts away from capital.

Panhandle Regional Expansion Project (PREP) Strategy Development

The Panhandle Regional Expansion Project (PREP) is required to provide reliable, secure, economic natural gas supply to meet the growing design day demand of the EGI Panhandle Transmission System which serves in-franchise markets (including residential, commercial and industrial customers). As a result of a non-binding Expression of Interest (EOI) conducted in February 2021, EGI is forecasting firm transportation growth driven by general service growth, greenhouse market demand in Leamington / Kingsville / Chatham-Kent and industrial demand in Windsor requiring incremental facilities as early as winter 2023-24. Alternatives are being evaluated at varying levels of detail depending upon project feasibility including engineering, cost, construction feasibility, capacity and reliability. Through this process, EGI will identify the most efficient project to provide the Panhandle Transmission System with reliable supply and adequate capacity for both design day conditions and operational conditions. As part of the project plan, EGI will complete a supply-side IRP assessment in addition to a binding reverse open season. In this way, EGI will minimize the facilities required to serve incremental demand while optimizing any unwanted existing capacity.

Dawn to Corunna Strategy Development

The Corunna Compressor Station (CCS) is comprised of 11 reciprocating compressors. With the units having been in service for more than 50 years, obsolescence, reliability and employee safety concerns have been identified. Further risk assessment has been completed and has confirmed that risks at this location must be addressed.

To mitigate the risks at this facility 20km of NPS 36 pipeline will be installed from Dawn to Corunna Compressor Station. The investment includes the retirement of 7 compressor units. This project replaces the equivalent design day storage capacity of 1.4PJ/d provided by the 7 compressors and will re-utilize horsepower at Dawn to replace the capacity. The in-service date is targeted for November 1, 2023.

.

5 Summary of Capital Expenditures

5.1 Enbridge Gas Distribution (EGD) Rate Zone

Table 5.1-1 shows the 2022 forecast published in the 2021-2025 AMP and the proposed 2022 capital budget (including those projects for which EGI will seek ICM treatment) for the EGD rate zone and lists any variance explanations. As discussed in **Section 2**, emerging and revised projects were identified and evaluated based on the existing 2022 portfolio. No changes have been reflected to future year portfolios, as such, no updates were required to the assumptions in **Section 6.3** of the 2021-2025 EGI Asset Management Plan. No changes were made to inflation assumptions for future year projects. Updated cost estimates were prepared for new or revised 2022 projects. Projects with solution scopes still under development are not included in the five-year portfolio of spend.

Table 5.1-1: 2022 EGD Capital Budget (including ICM) and Variance Explanations (Includes Overheads)

Asset Class	2022 AMP	2022 Budget	Variance	Variance Explanation*
Growth	169,264,022	145,964,276	(23,299,746)	• **+$2.0M** – Minor increases to the customer connections budget • **+$4.9M** - New mCHP (micro combined heat and power) carbon reduction initiative at TOC • **-$30.2M** – Project deferrals as a result of lower growth forecast
Distribution Pipe	201,658,502	278,365,794	76,707,292	• **+$48.6M** - St. Laurent Phase 3 increase due to refinement in project scope and costing (ICM-eligible) • **+$42.9M** - NPS 20 Lake Shore Replacement (Cherry to Bathurst) portion of work deferred to 2022 due to permitting delays (ICM-eligible) • **+$17.7M –** Variance in main replacement program due to project pacing and updates to scope and costing • **+$4.1M** – Increase to integrity program due to updated scope and costing • **-$12.3M** - St. Laurent Phase 4 deferred from 2022 to 2023 due to permitting delays and refinement in project scope and costing • **-$17.9M** - Decrease to relocation program due to additional information available on relocations, adjustments to regional forecasts, and NPS 20 Don River Waterfront Relocation Project rescoped and rescheduled • **-$6.6M** - Decrease in Service Relay program (including AMP fittings)
Distribution Stations	52,196,652	54,447,658	2,251,007	• **+$2.3M** - Variances to the station's portfolio are due to refined project costing and timing.
Utilization	54,065,392	50,050,055	(4,015,337)	• **+$3.1M** – New AMI Pilot Project to support carbon reduction initiatives • **-$4.1M** – Decrease in Meter Purchases due to extended seal life on existing meters and reduced customer connections forecast

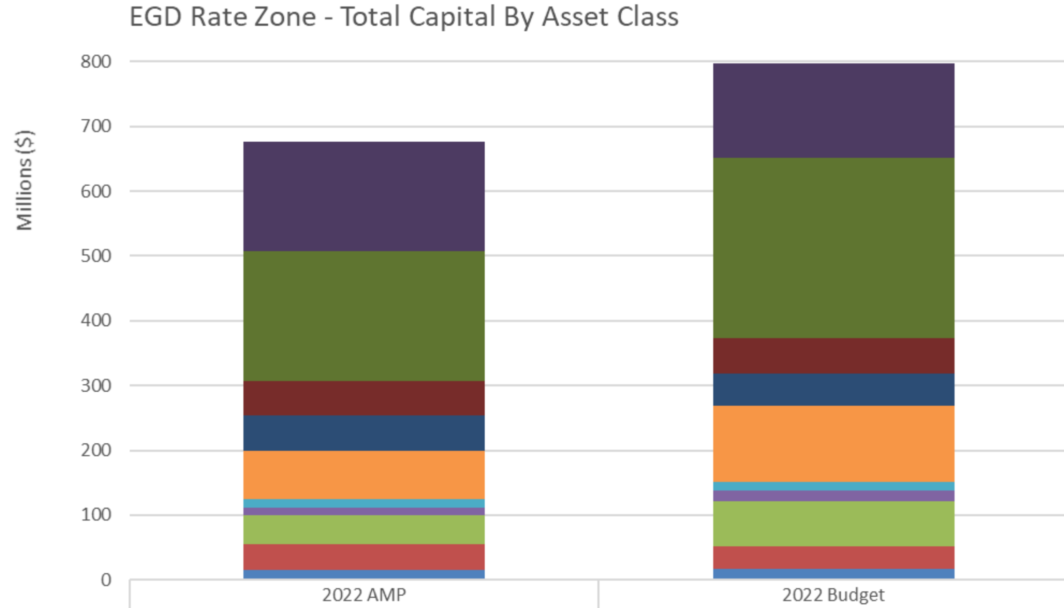
.

Asset Class	2022 AMP	2022 Budget	Variance	Variance Explanation*
				• **-$3.0M** – Decrease in Regulator Refits due to program alignment with meter purchase decrease
Compression Stations	74,671,947	116,669,696	41,997,750*	• **+$67.9M** - Dawn to Corunna required in 2023 based on site-wide assessment • **+$3.7M** - SCRW: Station-Renewal-In-Place increase to reflect full scope and costing refinement • **-$27.7M** - Deferral of Dehydration Expansion for additional scoping and risk assessment • **-$3.2M** - Header valve replacement deferral due to construction conflicts • **-$2.5M** - Decrease in foundation block replacements due to construction timelines
Transmission Pipe & Underground Storage	14,538,164	13,041,576	(1,496,588)	• **-$1.5M** - Deferral of MOP verification program offset by various changes to project cost, scope, and timing
Fleet & Equipment	11,093,573	17,298,044	6,204,471	• **+$6.1M** - ProStopp T.D. Williamson isolation tool for double block and bleed isolation
Real Estate & Workplace Services	44,881,511	68,967,968	24,086,457	• **+$3.8M** – Net increase to Kennedy Road Expansion variance due to updated scope and costing, offset by the land advancement from 2022 to 2020 • **+$22.1M** - Station B phasing combined • **+$3.9M** - Variance due to market availability and project scope variation to meet business facility requirements • **-$5.7M** - Kelfield Operations Centre deferral
TIS	39,364,731	35,269,869	(4,094,863)	• **-$4.1M** – Variance reflects evolving business needs including Green Button initiative (Ministry of Energy), transition to cloud services, and deferral of eGIS Upgrade
EA Fixed O/H	15,433,416	16,876,097	1,442,681	• **+$1.4M** - Variance driven by new emergency response services
Total	677,167,909	796,951,033	119,783,124	

*Instances where discrepancies exist between the Variance column and Variance Explanations are due to multiple immaterial changes (cost, scope, timing) across the asset class.

Figure 5.1-1 shows a graphic view of **Table 5.1-1**.

.



	2022 AMP	2022 Budget
Growth	169.3	146.0
Distribution Pipe	201.7	278.4
Distribution Stations	52.2	54.4
Utilization	54.1	50.1
Compression Stations	74.7	116.7
Transmission Pipe & Underground Storage	14.5	13.0
Fleet & Equipment	11.1	17.3
Real Estate & Workplace Services	44.9	69.0
TIS	39.4	35.3
EA Fixed O/H	15.4	16.9

Figure 5.1-1: EGD Rate Zone 2022 AMP and Proposed 2022 Budget Comparison

Table 5.1-2 shows the list of ICM-eligible projects requesting ICM treatment in 2022 for the EGD Rate Zone Portfolio.

.

Table 5.1-2: EGD Rate Zone ICM-eligible Projects Requesting ICM Treatment in 2022 (Includes Overheads)

Asset Class	Project Name	In-Service Year	2022F
Distribution Pipe	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	2022	90,701,884
Distribution Pipe	St. Laurent Phase 3	2022	84,512,270

Table 5.1-3 shows the 2021 forecast published in the 2021-2025 AMP compared to the proposed 2022 Capital Budget for the EGD Rate Zone Portfolio.

Table 5.1-3: 2021 AMP Forecast vs 2022 EGD Capital Budget (including ICM) and Variance Explanations (Includes Overheads)

Asset Class	2021 AMP	2022 Budget	Variance	Variance Explanation
Growth	160,121,547	145,964,276	(14,157,271)	• Reduction in reinforcement projects and customer connections due to decreased customer growth forecast
Distribution Pipe	202,005,036	278,365,794	76,360,758	• Increase in ICM-eligible main replacement projects including St. Laurent Ph 3 and NPS 20 Lake Shore Replacement (Cherry to Bathurst) • Increase in main replacements to move towards project pacing with vintage steel replacement strategy and updates to scope and costing • AMP fitting program decreased due to COVID-19 work restrictions • Variance in relocation projects based on adjustments to regional forecasts as scope was defined and the NPS 20 Don River Waterfront Relocation Project rescoped and rescheduled • Service relay volumes decreased due to COVID-19 work restrictions
Distribution Stations	42,077,122	54,447,658	12,370,537	• Variance due to adjustments in project timing and scope
Utilization	55,344,899	50,050,055	(5,294,844)	• New AMI Pilot Project to support carbon reduction initiatives • Decrease in Meter Purchases due to extended seal life on existing meters and reduced customer connections forecast
Compression Stations	46,080,772	116,669,696	70,588,924	• Variance due to pacing of large projects including Dawn to Corunna, SCRW: Station-Renewal In-Place, Dehydration Expansion and SCOR: Meter Area Upgrade Ph 1 and Ph 2 • Variance in header valve replacement program due to refined program pacing
Transmission Pipe & Underground Storage	12,537,255	13,041,576	504,321	• Variance due to project pacing and scope of growth, integrity and replacement projects

.

Asset Class	2021 AMP	2022 Budget	Variance	Variance Explanation
Fleet & Equipment	10,864,230	17,298,044	6,433,814	• Addition of ProStopp T.D. Williamson isolation tool to tools program
Real Estate & Workplace Services	59,555,512	68,967,968	9,412,456	• Variance due to market availability of land and project scope variation to meet evolving business facility requirements
TIS	28,216,375	35,269,869	7,053,494	• Variance due to changing business requirements year over year, project timing and transition to cloud services.
EA Fixed O/H	15,363,322	16,876,097	1,512,775	• Variance driven by new emergency response services
Total	632,166,068	796,951,033	164,784,965	

5.2 Union Gas Limited (Union) Rate Zones

Table 5.2-1 shows the 2022 forecast published in the 2021-2025 AMP and the proposed 2022 capital budget (including ICM) for the LUG rate zones and lists any variance explanations. As discussed in **Section 2**, emerging and revised projects were identified and evaluated based on the existing 2022 portfolio. No changes have been reflected to future year portfolios, as such, no updates were required to the assumptions in **Section 6.3** of the 2021-2025 EGI Asset Management Plan. No changes were made to inflation assumptions for future year projects. Updated cost estimates were prepared for new or revised 2022 projects. Projects with solution scopes still under development are not included in the five-year portfolio of spend.

Table 5.2-1: 2022 Union Rate Zones Capital Budget (including ICM) and Variance Explanations (Includes Overheads)

Asset Class	2022 AMP	2022 Budget	Variance	Variance Explanation
Growth	117,152,328	122,601,762	5,449,434	• Change in reinforcement timing and scope due to changes in the growth forecast: ○ **+$3.5M** - Byron Transmission Station (ICM-eligible) ○ **+$1.2M** - PREP: Sandwich Station Rebuild ○ **-$9.9M** – Dunnville Line Reinforcement ○ **-$0.3M** - Various reinforcement projects • **+$10.9M -** Increase in the greenhouse market growth and to overall connection costs
Distribution Pipe	143,203,808	140,202,509	(3,001,300)	• **+$1.1M -** Coniston Lateral Replacement Class Location project delayed • **+$2.7M** - Windsor Line Replacement Project - West portion deferred from 2021 to 2022 due to permitting delays • **+$2.7M** - Increase in main replacements due to multiple small projects with spend continuing from 2021 into 2022

.

Asset Class	2022 AMP	2022 Budget	Variance	Variance Explanation
				• **-$2.2M** - Kingston Lateral Class Location project deferred from 2022 to 2023 to facilitate an integrated solution • **-$3.7M** - NPS 20 Shorted Casing on Hwy 5 Phase 2 deferred from 2022 to 2023 • **-$0.2M -** Kirkland Lake Lateral Replacement (ICM-eligible) project estimate refinement • **-$3.3M** - Service relay program (including AMP fittings) decrease due to updated cost estimates
Distribution Stations	44,736,824	52,932,232	8,195,408	• **+$2.0M** - New Fire Suppression and Auto Transfer Generator retrofit program driven by compliance requirements • **+$2.1M** - Advancement of CNG projects • **+2.5M** - Inside Regulator & ERR Program • **+$1.5M** - Various changes to distribution station project cost, scope, and timing
Utilization	56,200,414	60,428,343	4,227,929	• **+$4.2M** – Increase in regulator refit program due to increased labour costs for meter exchanges and exchanges deferred from 2021 to 2022
Compression Stations	32,463,410	27,475,302	(4,988,108)	• **+$9.0M** - PREP: Dawn South Yard Piping Modifications required to support increased growth • **+$1.2M** - Control valve replacement required based on results from 2020 leak detection assessment • **+$4.4M** – Increase to replacement program • **+$0.9M** – Increase to integrity program • **-$19.7M** - Deferral of Dawn C Compression Lifecycle project based on updated information from the OEM on equipment obsolescence • **-$0.9M** - Sandwich Gas Generator Overhaul advanced to 2021 due to a failure
Liquified Natural Gas	243,400	471,563	228,163	• **+$0.2M** - Hagar Backup Generator Control Panel replaced based on deteriorating condition and obsolescence
Transmission Pipe & Underground Storage	265,974,525	118,230,883	(147,743,642)	• **+$63.0M** – Inclusion of PREP: Panhandle Expansion Project based on current growth model projections • **+$3.9M** - Increase in strategic land purchases to manage land use adjacent to facilities based on market availability • **-$208.2M** - Dawn Parkway Expansion (Kirkwall to Hamilton NPS 48) in service date deferred • **-$6.7M** - Dawn to Cuthbert NPS 42 Replacement variance from timing of the multiyear spend (ICM-eligible)
Fleet & Equipment	11,950,938	14,750,964	2,800,026	• **+$2.5M** - Increase in vehicle purchases due to vehicle assignment policy. Vehicle assignment is based on number of kilometers driven by employee in identified role and type of field work requiring a vehicle

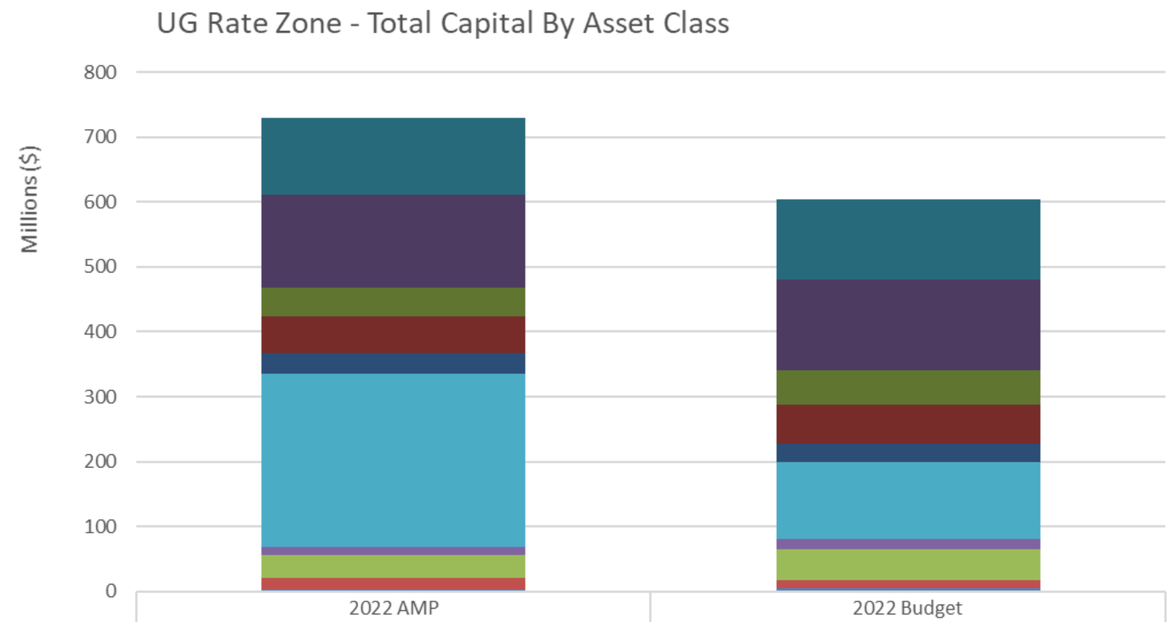
.

Asset Class	2022 AMP	2022 Budget	Variance	Variance Explanation
Real Estate & Workplace Services	35,735,785	49,407,369	13,671,584	• **+$5.0M** – Variances from project advancement and deferrals due to market availability and project scope variation to meet business facility requirements • **+$8.6M** – Variance due to updated cost estimates
TIS	18,186,240	12,096,826	(6,089,414)	• **-$6.1M** – Variance reflects evolving business needs including reductions to the Next Generation Contact Centre, Operating Technologies Lifecycle project, and Customer Data Analytics Solutions due to changing business requirements/timing
EA Fixed O/H	2,962,499	4,467,175	1,504,676	• **+$1.5M** - Variance due to updated alliance partner contracts
Total	728,810,170	603,064,928	(125,745,242)	

*Instances where discrepancies exist between the Variance column and Variance Explanations are due to multiple immaterial changes (cost, scope, timing) across the asset class.

Figure 5.2-1 shows a graphic view of **Table 5.2-1.**

.



	2022 AMP	2022 Budget
Growth	117.2	122.6
Distribution Pipe	143.2	140.2
Distribution Stations	44.7	52.9
Utilization	56.2	60.4
Compression Stations	32.5	27.5
LNG	0.2	0.5
Transmission Pipe & Underground Storage	266.0	118.2
Fleet & Equipment	12.0	14.8
Real Estate & Workplace Services	35.7	49.4
TIS	18.2	12.1
EA Fixed O/H	3.0	4.5

Figure 5.2-1: Union Rate Zones 2022 AMP and Proposed 2022 Budget Comparison

Table 5.2-2 shows the list of ICM-eligible projects requesting ICM treatment in 2022 for the Union Rate Zones Portfolio.

.

Table 5.2-2: Union Rate Zones ICM-Eligible Projects (Includes Overheads)

Asset Class	Project Name	In-Service Year	2022F
Growth	Byron Transmission Station (13N-501)	2022	3,469,947
Distribution Pipe	Kirkland Lake Lateral Replacement	2022	19,933,738
Transmission Pipe & Underground Storage	Dawn to Cuthbert NPS 42 Replacement	2022	22,034,262

Table 5.2-3 shows the 2021 forecast published in the 2021-2025 AMP compared to the proposed 2022 Capital Budget for the Union Rate Zones Portfolio.

Table 5.2-3: 2021 AMP Forecast vs 2022 Union Rate Zones Capital Budget (including ICM) and Variance Explanations

Asset Class	2021 AMP	2022 Budget	Variance	Variance Explanation
Growth	116,948,438	122,601,762	5,653,324	• Change in reinforcement timing and scope due to changes in the growth forecast • Increase in the greenhouse market growth and to the overall connection costs
Distribution Pipe	280,391,020	140,202,509	(140,188,512)	• Decrease in main replacements in 2022 due to larger ICM-projects executed in 2021, including London Lines ($112.7M) and Windsor Lines ($7.8M) • Decrease in 2022 Corrosion Program due to large 2021 discrete project: 20" Shorted Casing on Hwy 5 - Phase 1 • Variance in Integrity Program due to project pacing • Decrease in relocation projects based on adjustments to regional forecasts as scope was defined • Proactive service relay volumes decreased due to COVID-19 work restrictions • 2021 class location projects deferred into 2022
Distribution Stations	52,280,148	52,932,232	652,085	• No significant variance
Utilization	55,209,960	60,428,343	5,218,382	• Increase in regulator refit program due to increased labour costs for meter exchanges and exchanges deferred from 2021 to 2022

Asset Class	2021 AMP	2022 Budget	Variance	Variance Explanation
Compression Stations	9,293,225	27,475,302	18,182,077	• Variance due to defined pacing, scope and cost estimates of improvement and replacement projects • Increase in conversions from high bleed devices to low/no bleed driven by methane emissions regulation • Increase to 2022 overhaul program due to Bright A2 Gas Generator Mid Life Overhaul • Increase in growth projects due to PREP: Dawn South Yard Piping Modifications
LNG	339,327	471,563	132,236	• Variance due to pacing and scope of improvement projects
Transmission Pipe & Underground Storage	53,087,383	118,230,883	65,143,500	• Increase in large projects including Panhandle Expansion Project and Dawn to Cuthbert NPS 42 Replacement (ICM-eligible) • Increase in strategic land purchases to manage land use adjacent to facilities based on market availability • Increased spend in integrity program due to pacing of strategy • Variance in replacement and class location programs due to pacing and scope
Fleet & Equipment	11,726,653	14,750,964	3,024,310	• Increase in vehicle purchases due to vehicle assignment policy. Vehicle assignment is based on number of kilometers driven by employee in identified role and type of field work requiring a vehicle
Real Estate & Workplace Services	44,927,608	49,407,369	4,479,761	• Variance due to market availability and project scope variation to meet business facility requirements
TIS	11,323,128	12,096,826	773,698	• No significant variance
EA Fixed O/H	2,785,100	4,467,175	1,682,075	• Variance due to updated alliance partner contracts
Total	638,311,991	603,064,928	(35,247,063)	

.

ENBRIDGE GAS INC.

PROGRESS REPORT ON IMPLEMENTATION OF SCOTTMADDEN RECOMMENDATIONS ON UNACCOUNTED FOR GAS (UFG)

CONTENTS

1.0 INTRODUCTION

1.1 PURPOSE

In its 2016 Earnings Sharing and Deferral Account Disposition proceeding (EB 2017-0102), legacy Enbridge Gas Distribution agreed to review potential metering issues that might be contributing to Unaccounted for Gas (UFG) and to report on that review as part of the 2018 Rate Adjustment Application[1]. In the 2018 Rate Application, Legacy Enbridge Gas Distribution agreed to continue this review and report on it as part of the 2019 Rate Adjustment Application.[2] In the MAADs decision EB-2017-0306/EB-2017-0307, the Ontario Energy Board (OEB) directed Enbridge Gas Inc (Enbridge Gas or EGI) to file a report on UFG for both legacy Union Gas (LUG) and legacy Enbridge Gas Distribution (LEGD) service areas by December 31, 2019. Accordingly, Enbridge Gas filed a UFG report (the UFG Report) prepared by ScottMadden Management Consultants in December 2019. The UFG Report reviewed and evaluated factors contributing to UFG for the legacy Companies. The Report indicated that the main sources of UFG included retail meter variations, gate station meter variations, leaks, fugitive emissions, third-party theft, company use and accounting adjustments.

The UFG Report was considered as part of the 2020 Rate Application Phase 2 (EB-2019-0194). In that proceeding, Enbridge Gas committed to "….report upon its progress in implementing the recommendations set out in the UFG Report in its 2022 rates filing."[3] Enbridge Gas has also committed in the same application[4] to assess its UFG forecasting methodology in the 2024 rebasing proceeding and to include information about the implementation of the UFG Report recommendations and other activities to address UFG, and the impacts of such activities. Furthermore, Enbridge Gas committed[5] to provide reporting of UFG results, segregated by rate zone and activity (distribution, transmission, storage), with the most recent historical information as part of the rebasing filing.

Enbridge Gas has always monitored and actively managed UFG. The UFG Report provided numerous recommendations to enhance the ongoing efforts already in place. This update provides details of Enbridge Gas' progress in implementing the recommendations set out in the UFG Report. The recommendations from the UFG Report were to "identify and standardize "best practices" across the legacy

---

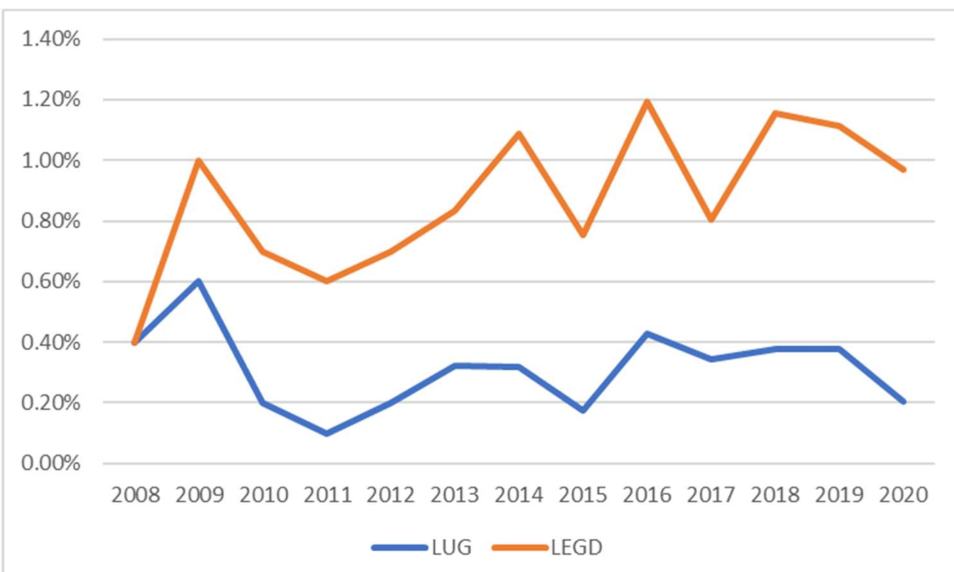
[1] EB-2017-0102, Settlement Proposal, page 14.
[2] EB-2017-0086, Settlement Proposal, Exhibit N2, Tab 1, Schedule 1, page 12.
[3] EB-2019-0194, Reply Argument of Enbridge Gas dated May 1, 2020, page 33; EB-2019-0194, Decision and Order dated May 14, 2020, page 20.
[4] EB-2019-0194, Reply Arguement, page 34.
[5] EB-2019-0194, Reply Arguement, page 34

Companies…..document data, processes and studies related to monitoring and managing UFG……[and] investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG”[6]. This update outlines how Enbridge Gas is actively taking steps to implement the recommendations from the UFG Report, while continuing to prudently monitor and manage UFG.

1.2 UNACCOUNTED FOR GAS (UFG) OVERVIEW

UFG is broadly defined as the difference between gas receipts and gas deliveries, where gas receipts are volumes that enter the distribution system and gas deliveries are volumes that exit the distribution system. Gas receipts generally include gas supplies from pipeline and withdrawals from on-system storage facilities, while gas deliveries generally include sales to retail customers and injections into on-system storage facilities. The UFG Report included benchmarking analysis that demonstrated that UFG as a percentage of throughput for both legacy Companies was lower than its peers. Figure 1 shows UFG as a percentage of throughput for both legacy Companies. UFG as a percentage of throughput for both legacy Companies has remained flat or decreased for the last five years.

Figure 1: UFG as a % of Throughput for LUG and LEGD



[6] EB 2019-0194, ScottMadden Report, December 2019, page 47.

Figure 2: Historical UFG Volumes and % of Throughput

Year	LEGD UFG Volume (103m3)	LUG UFG Volume (103m3)	LEGD UFG as a % of Throughput	LUG UFG as a % of Throughput
2008	44,424	143,880	0.373%	0.411%
2009	110,917	201,845	0.981%	0.637%
2010	72,104	67,283	0.662%	0.192%
2011	73,355	35,668	0.647%	0.105%
2012	74,762	68,690	0.711%	0.210%
2013	97,361	113,997	0.834%	0.320%
2014	135,380	97,109	1.089%	0.318%
2015	88,438	54,408	0.752%	0.174%
2016	133,112	131,588	1.194%	0.427%
2017	93,077	108,901	0.804%	0.342%
2018	142,086	136,447	1.157%	0.379%
2019	140,594	137,652	1.114%	0.376%
2020	110,234	74,120	0.968%	0.208%

2.0 MAIN SOURCES OF UFG

OVERVIEW

As part of its research and analysis for the UFG Report, ScottMadden identified certain common sources of UFG across the industry, including physical losses (eg.leaks, third-party damage and venting during construction and maintenance activities), metering variations, non-registering meters, theft, line pack and billing and accounting adjustments. ScottMadden also determined that the sources of UFG for the legacy Companies were generally consistent with those at other gas utilities. The following sections provide additional detail regarding the sources of UFG at Enbridge Gas.

2.1 PHYSICAL LOSSES

Physical losses are a source of UFG at Enbridge Gas. Contributors to physical losses include: leaks and emissions from natural gas facilities, releases of natural gas during maintenance, construction and emergency situations, and line hits due to third-party construction or excavation activities.

Enbridge Gas reports fugitive, vented and flared emissions annually to Environment and Climate Change Canada and the Ontario Ministry of Environment, Conservation and Parks. Figure 3 shows a 15% decline in emissions and leaks within the consolidated Enbridge Gas operations from 2015 to 2020. The slight increase in leaks and fugitive emissions reported in 2019 and 2020 is a result of the use of improved emissions factors. Since 2018, Enbridge Gas continues to refine the emissions and activity factors used to quantify and estimate leaks and fugitive emissions. Changes to these factors are described in EGI Interrogatory Response (EB-2019-0194, Exhibit I.STAFF.30), as well as in section 3.1 (iii) of this report. Figure 3 shows lost gas from leaks and emissions on a combined basis for Enbridge Gas, while Figure 4 provides a breakdown of the total leaks and emissions for Enbridge Gas by type.

Figure 3: Lost Gas from Leaks and Emissions (10^6m^3)

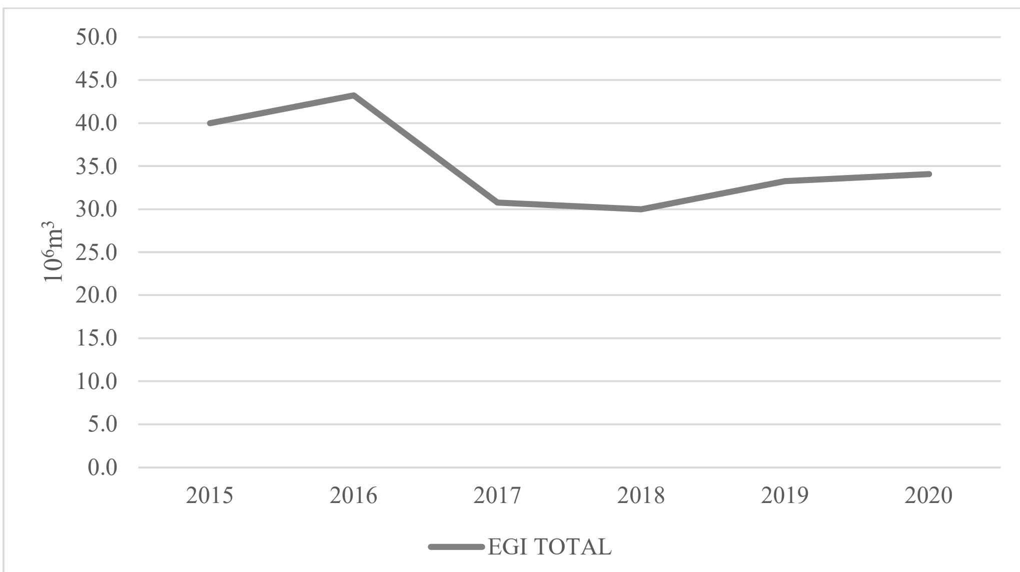
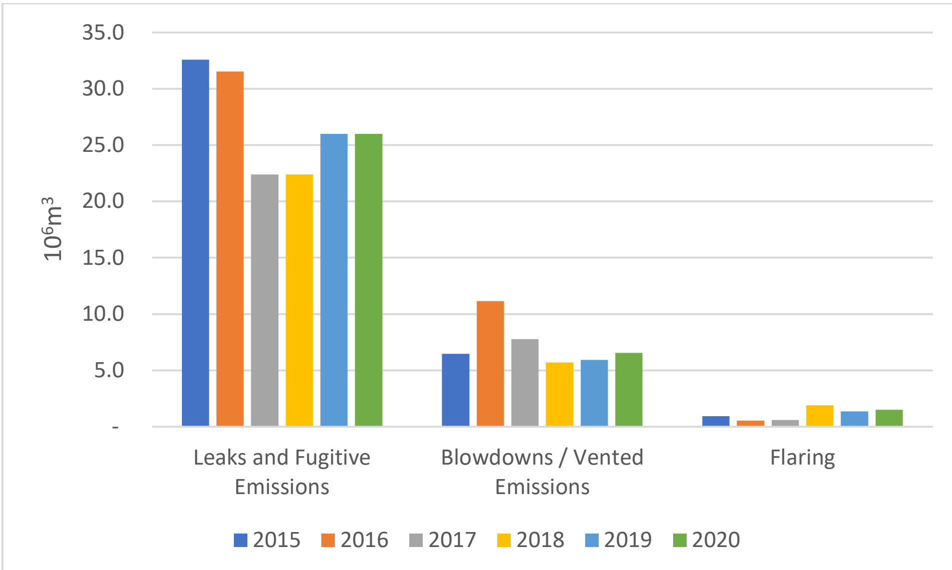


Figure 4: Lost Gas from Leaks and Emissions (10^6m^3) by Type



2.2 Retail Meter Variations

Retail meter variations represent variations between actual and metered volumes at customer locations. These variations can be attributed to factors including: inherent measurement uncertainties of meters, meter failure, inaccurate corrections for temperature and pressure variations or improperly sized meters. Enbridge Gas conducts meter testing on a sample of diaphragm meters annually. These tests are conducted under low-flow and high-flow conditions. Historical test results going back to 2014 are shown in Figure 5 and 6 below.

Figure 5: LEGD Meter Test Results vs Measurement Canada (MC) Standard

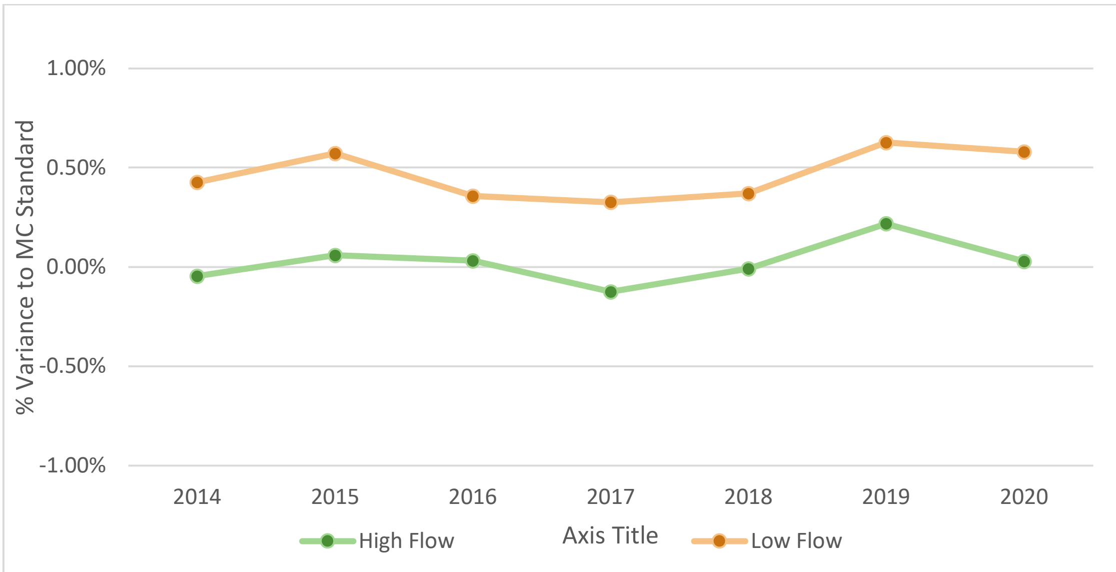


Figure 6: LUG Meter Test Results vs Measurement Canada (MC) Standard

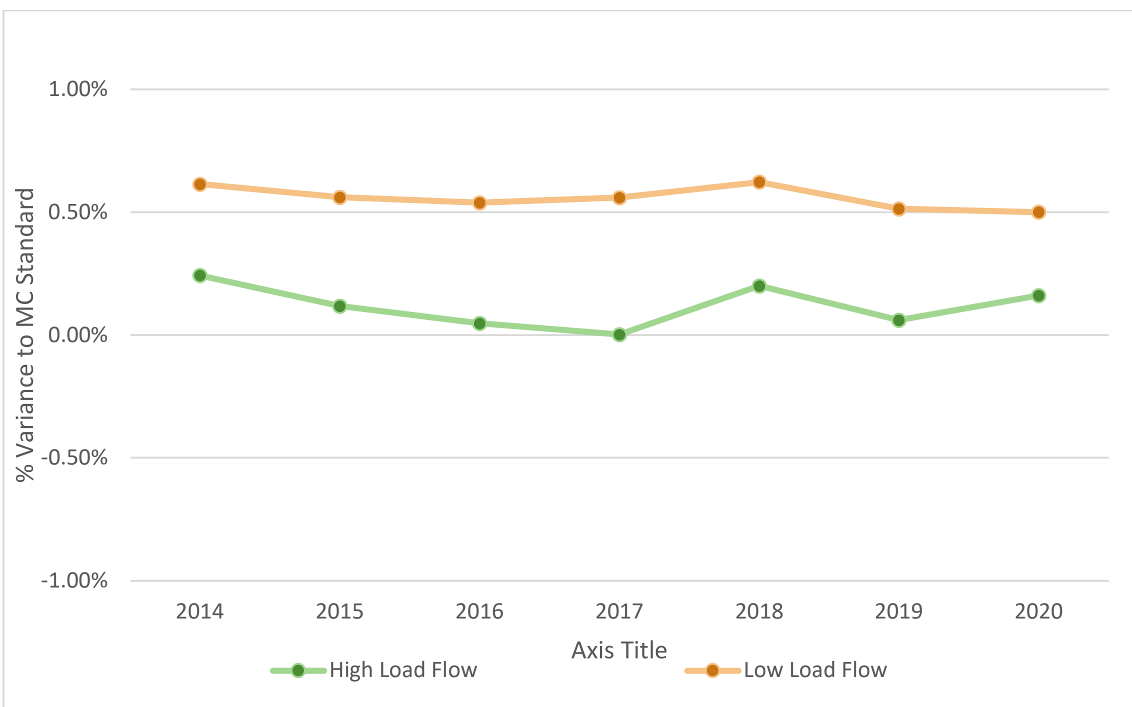


Figure 5 and 6 show that tests under high-flow and low-flow conditions result in the following variances since 2014:

	High-Flow Conditions % Variance to Measurement Canada Standard	Low-Flow Conditions % Variance to Measurement Canada Standard
LEGD	0.02%	0.47%
LUG	0.12%	0.56%

The variances to the Measurement Canada standard are within the Measurement Canada tolerance of +/- 3.0 percent. Meters whose test results that fall outside of the +/- 3.0 percent tolerance are taken out of service. All rotary turbine, and ultrasonic meters are tested on a frequency which is prescribed by Measurement Canada[7].

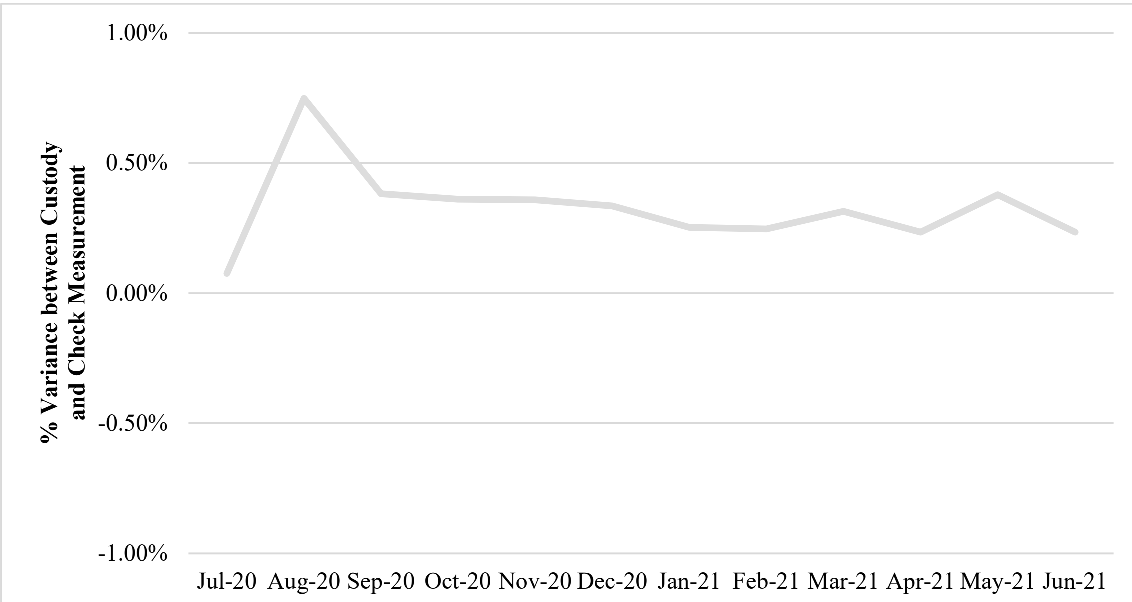
2.3 GATE STATION METER VARIATIONS

Gate station meter variations represent a potential source of UFG if there are differences at receipt points between actual and metered volumes. However, not all gate station meter variations can be wholly attributable to UFG, as the variations may only represent differences in meters, and may not represent actual lost gas.

Enbridge Gas utilizes check meters to validate the accuracy of the custody or supplier meters. A comparison between Enbridge Gas' check meters and third-party custody transfer meters is depicted in Figure 7 below. This figure demonstrates that Enbridge Gas' check measurement falls within the Measurement Canada prescribed range of +/- 3% and with the +/- 2% tolerance of the Enbridge Gas internal benchmark.

[7] Gas Bulletin G-18: Reverification periods for gas meters, ancillary devices and metering installations (http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00607.html) and
Gas Bulletin G-03: Natural gas meters and ancillary devices qualified for a lengthened initial reverification period, identifies meter manufacturers and models (http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00576.html)

Figure 7: Third Party Custody Transfer vs Enbridge Gas Check Meters Differences



2.4 <u>OTHERS</u> *(INCL. ACCOUNTING ADJUSTMENTS, COMPANY USE, THEFT AND NON-REGISTERING METERS)*

The remaining primary contributors of UFG at Enbridge Gas include theft and non-registering meters, company use, and accounting adjustments. Theft and non-registering meters account for volumes that are not metered or recorded due to unauthorized use or faulty equipment. Company use contributor represents the portion of company use volumes used by Enbridge Gas that are not metered and/or recorded. Accounting adjustments represent variations between actual and reported volumes due to various accounting adjustments, including unbilled sales adjustments, billing adjustments, line pack and other accounting related adjustments.

3.0 UPDATE ON RECOMMENDATIONS BY SOURCE

SUMMARY OF SCOTTMADDEN RECOMMENDATIONS

In the UFG Report, ScottMadden recommended that Enbridge Gas identify and standardize "best practices" across the legacy Companies. ScottMadden also recommended that Enbridge Gas document data, process and studies related to monitoring and managing UFG. Finally, ScottMadden recommended that, on a periodic basis, Enbridge Gas investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG. In addition to these general recommendations, ScottMadden also provided recommendations specific to each of the main sources of UFG. The following sections highlight the work that has been done for each of these recommendations in relation to each main source of UFG.

3.1 Physical Losses

i. Identify and Standardize Best Practices at EGI

Enbridge Gas implemented a harmonized leak operating standard across the legacy Companies in July 2020. This new standard includes: harmonized internal compliance requirements for leak monitoring and repair timelines, increased traceability and tracking of leak repairs (including the addition of new work order types corresponding to type and severity of leaks, an enhancement for both legacy Companies), increased monitoring frequencies and harmonized repair timelines for above ground leaks (which increased the frequency of monitoring for LEGD assets to align with the LUG standard), harmonization of survey cycles based on asset age and pressure (designed to survey assets with higher probability of failure on a more frequent cycle), and initiation of the station leak survey program.

In conjunction with the new leak operating standard, Enbridge Gas has developed a three-year program to eliminate a backlog of leaks identified prior to the roll out of the new standard.

In the area of controlled releases of gas during maintenance and construction activities, Enbridge Gas has been able to leverage best practices across the legacy Companies. LUG historically relied on lower pressure markets, where available, to draw down sections of pipeline for construction and maintenance, with the remaining gas vented to atmosphere. Since the integration of the two legacy Companies, Enbridge Gas has been able to leverage a portable drawdown compressor previously utilized by LEGD for construction related maintenance activities across the legacy Companies service areas.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

As noted in the UFG Report, Enbridge Gas has a program to review and evaluate replacement of bare-steel mains. This is an existing program that was in place prior to the amalgamation of the two Legacy Companies, originating from the LUG Pipeline Integrity Management Program, and more recently, has been included in Enbridge Gas' Asset Management Plan. Since 2019, approximately 9,800 kms of bare-steel mains have been replaced across the Enbridge Gas service area, with a target of replacing all remaining bare-steel mains by the end of 2024.

Enbridge Gas also has a program in place to replace vintage steel and plastic mains. This program leverages the Asset Health Review (AHR) process to forecast when corrosion and crack leaks might occur. The AHR process involves an evaluation of Enbridge Gas' gas carrying assets and their characteristics. The AHR utilizes reliability and risk models, both of which were updated in 2021 with additional historical data, and in some case, updates to the methodologies used in the models. A risk assessment is developed using the results of the reliability and risk models and an evaluation of the consequences of failure. This assessment is used to proactively select main replacements.

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas continues to sponsor emissions studies, in partnership with the Canadian Energy Partnership for Environmental Innovation (CEPEI) and its member natural gas companies across Canada. The goal of these studies is to improve emission and activity factors and emission estimation methodologies in the natural gas storage, transmission and distribution industry. Recent studies have been completed to better quantify emissions related to residential, commercial and industrial meter sets, with the updated emission and activity factors results being incorporated into the Enbridge Gas emissions inventory starting with the 2019 emissions inventory. Additionally, Enbridge Gas is part of a study that is currently underway to update emission and activity factors related to valve sites. The survey work for the study was completed in 2020, and the results of the study are pending.

iv. Implement New Practices and Initiatives

Enbridge Gas has implemented new practices and initiatives relating to damage reduction and reduction of methane emissions from venting and fugitive leaks.

In 2020, the federal Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (Methane Regulation) came into effect, to help reduce methane emissions from Canada's oil and gas sector. In response to the Methane Regulation, Enbridge Gas has introduced programs and initiatives targeted at reducing fugitive and vented gas.

Enbridge Gas implemented a more robust leak detection and repair (LDAR) program within its Storage and Transmission operations in 2020. The LDAR program details the frequency of completion of leak surveys at compressor, storage and metering stations within Enbridge Gas' storage and transmission system, as well as specifying the timelines for completing leak repairs. The frequency of leak surveys increased from annually to three times per year. The goal of the LDAR program is to improve the detection and repair of leaks, resulting in a reduction in leaks and fugitive emissions, as well as reducing UFG. Additionally, results from these surveys have been incorporated into the Enbridge Gas GHG inventory, starting with the 2019 inventory.

Furthermore, starting in 2020, compressor unit rod packing and seal venting emissions are measured in order to meet regulatory emissions targets. In response to this regulatory requirement, Enbridge Gas implemented a measurement and compliance program in 2020 with respect to compressor venting, which includes measurement timelines, emission limits and repair deadlines for units that are over the limit. As such, vented emissions from this emissions source are expected to be reduced as compared to historical emissions.

Enbridge Gas has also implemented a program to replace continuous high-bleed pneumatic devices with low-bleed or no-bleed alternatives during the 2021-2022 calendar years. This will result in a reduction of vented emissions from pneumatic devices within storage and transmission operations.

Pipeline maintenance activities have begun to utilize an incinerator, which combusts the gas entering the atmosphere rather than venting methane. This practice began in 2021. The primary use has been to create the proper flow conditions on a pipeline to facilitate in-line inspections or to condition new pipelines during initial odourization, however it has the secondary benefit of reducing GHG emissions in lieu of venting.

Enbridge Gas has also developed a Damage Reduction Strategy, which commenced in 2021. This strategy includes a specific focus on reinforcement of safe excavation practices with contractors working in the vicinity of Enbridge Gas assets, increasing homeowner awareness and education on locate requirements and excavation guidelines (including the promotion of the "Call Before You Dig" program), improving in-field engagement with third party excavators, and increasing proactive efforts with respect to high risk excavators and high risk locate tickets.

The Damage Reduction Strategy supplements on-going damage prevention activities. This includes identification of high risk assets during the locate process which allows Enbridge Gas to deploy personnel to monitor and communicate safe excavation practices, deploying aircraft and field personnel to patrol high risk pipelines to ensure no unauthorized excavations are occurring, and maintaining repeat offenders list provided to the Technical Standards and Safety Authority (TSSA). This addresses the recommendation in the 2019 ScottMadden report, which recommended that Enbridge Gas "….monitor and identify disturbances around high risk assets, including aerial patrol and vital main locate identification. Communicate with third party contractors prior to excavation"[8].

3.2 Retail Meter Variations

i. Identify and Standardize Best Practices at EGI

Beginning in 2021, Enbridge Gas standardized meter shop processes by adopting LUG' accredited processes. All meters are now tested under one common process. Diaphragm meter testing continues to be conducted annually under the integrated process. The results from tests conducted under low-flow and high-flow conditions continue to be well within Measurement Canada's regulations which prescribe maximum in-service limits of error of +/- 3.0%.

As noted in the UFG Report, there has been an ongoing effort to standardize the supercompressibility factors across the legacy Companies. Gas composition parameters and supercompressibility factors are used in Electronic Volume Integrators (EVI) and Remote Terminal Units (RTUs) to calculate the conversion of gas volumes from line conditions to standard conditions. There are various methods that can be used to do the calculation and each method requires gas quality parameters in order to calculate the supercompressibility factor. Gas quality parameters are updated periodically to ensure that the parameters match the quality of measured gas.

In the absence of specific regulatory or industry requirements relating to the updating of gas quality parameters, the approach for making updates differed amounst the two legacy Companies. LUG had been routinely updating gas quality parameters since 2002, while LEGD had not. Due to outdated fixed gas quality parameters, LEGD was under-calculating supercompressibility and under-measuring volumes, resulting in an increase in UFG volumes. In 2019, LEGD aligned with LUG and adopted the practice of updating gas quality parameters and supercompressibility factors, on a specified frequency, depending on the type of equipment, as described below.

In early 2020, Enbridge Gas began to implement the update of gas quality parameters and supercompressibility factors. This initiative was referenced in the 2019 ScottMadden report where it was recommended to "review and update supercompressibility parameters to more accurately measure and record volumes at elevated pressures"[9]. Enbridge Gas has aligned practices across both legacy Companies to regularly update gas quality parameters during routine pressure regulation and measurement inspections. These inspections vary from once every 6

[8] ScottMadden Report, December 2019, page 27
[9] ScottMadden Report, December 2019, page 31

months up to once every 5 years, depending on the station type and equipment within the station. These inspections fall under the Enbridge Gas Pressure Regulator Station Inspection Standard, which has also been updated and aligned across the two legacy Companies. The Pressure Regulator standard ensures that all stations are inspected and will have the gas quality parameters updated by 2025.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

N/A

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas stays abreast of industry practices and initiatives relating to retail measurement through its active participation in the Canadian Gas Association (CGA) Measurement and Regulation Steering Group. In addition to sharing best practices within the industry, the Steering Group also works closely with Measurement Canada, bringing forward recommendations relating to policies and regulations that impact the industry.

A focus of this working group recently has been the management of COVID-19 pandemic impacts as it relates to electricity and gas meter compliance and reverification requirements. The CGA has also recently proposed to form two working groups to address the finalization of specifications for Pressure Factor Metering and Ultrasonic Meter Specifications. The active participation with the CGA and Measurement Canada demonstrates Enbridge Gas's intent to stay abreast of and influence industry practices and initiatives.

iv. Implement New Practices and initiatives

A number of specific recommendations regarding the implementation of new practices and initiatives were noted in the UFG Report. First, it was recommended to:

> "Evaluate standardizing supercompressibility standards between interconnects and industrial customer sites to more accurately measure and record volumes. At interconnects, AGA-8 Supercompressibility standard is applied, while at industrial sites, the NX-19 standard is applied. The variation in standards can result in meters registering less than actual gas usage"[10]

[10] ScottMadden Report, December 2019, page 31

Enbridge Gas is in the midst of standardizing supercompressibility standards between interconnects and industrial customer sites. Enbridge Gas has developed a New Product Introduction process that provides direction regarding the approval of new measurement instruments, including Electronic Volume Integrators (EVIs) for use. Completion of this internal process is expected by Q1 2022. Upon completion of the process, EGI will start installing the AGA-8 Supercompressibility standard at industrial customer sites.

The 2019 UFG report also recommended to “Review Automated Meter Reading (“AMR”) and Advanced Metering Infrastructure (“AMI”) for improved accuracy of measured and recorded volumes”. While this was called out as a new practice by ScottMadden, both legacy Companies have previously completed AMR pilot projects to explore these technologies. LEGD initiated a pilot project in 2006 and LUG initiated a pilot project in 1999. In 2021, Enbridge Gas has engaged a cross functional team to complete an updated assessment of both AMR and AMI technologies. The team is currently evaluating the costs and benefits of AMR and AMI solutions. Efforts are underway to identify Enbridge Gas’ current risk profile and opportunities to reduce risk with an AMR or AMI solution. The team is also pursuing the execution of an AMI pilot program. The outcome of these evaluations will be incorporated into a proposal that will be filed with the OEB as part of the 2024 rebasing application.

3.3 GATE STATION METER VARIATIONS

i. Identify and Standardize Best Practices at EGI

As noted in the UFG report, gate station monitoring responsibilities were transferred to a specialized measurement group. Since that transition, there has been alignment and standardization of best practices for this function at Enbridge Gas, including increased monitoring of measurement data. Furthermore, the LEGD measurement data has been added to the LUG Gas Measurement Accounting System and is subject to additional automated validation checks, already utilized for LUG measurement data, including tolerances for volumes, temperature, pressure and data completeness. The measurement data for both legacy entities continues to be subject to the Sarbanes-Oxley (SOX) reporting requirement and is now consolidated within one reporting system and under the accountability of one group within Enbridge Gas.

In addition, a cross-functional measurement working group, focused on dealing with measurement issues and sharing of best practices, has been expanded to include representatives from across Enbridge Gas.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

In its 2016 Earnings Sharing and Deferral Account Disposition proceeding, LEGD agreed to review potential metering issues that might be contributing to UFG and to report on that review. LEGD also agreed to look specifically at the metering design at Victoria Square Gate Station.[11] In the LEGD amended settlement proposal in 2018 Rate Application[12], LEGD agreed to continue this review and report on its progress in the 2019 rate application. Further update was provided through the 2019 UFG Report completed by ScottMadden which was filed as part of the 2020 Rates Application Phase 2 (EB 2019-0194), noting that the project was scheduled to commence in 2020[13].

The redesign of the Victoria Square Gate Station was completed in 2020. Prior to the redesign, Victoria Square had one 30" ultrasonic meter run. The uncertainty of measurement of gas volumes with a single large meter is high, especially at low flow rates and this uncertainty of measurement can be a contributorto UFG variations. To reduce the measurement uncertainty, the Victoria Square Gate Station was upgraded to replace a single 30" meter run with 3 parallel ultrasonic meter runs: two 16" meters and a 4" meter.

The design also included staging so that the runs to each meter open or close depending on flow conditions, which provides a more accurate measurement over a greater range. This upgrade reduced the uncertainty of measurement by a factor of 1.4 (square root of the number of 16" meter runs) for normal flow rates and up to a factor of 5 for low flow rates.

The impact of the redesign of Victoria Sqare Gate Station was quantified in EGI Interrogatory Response (EB 2021-0149, Exhibit I.STAFF.10), where EGI noted that "A comparison of the measurement differences prior to the rebuild versus after the rebuild shows a reduction in volume difference from 12.4 $10^6 m^3$ to 2.65 $10^6 m^3$. While the UAF benefits can not be directly measured, as noted in the 2019 UAF study completed by ScottMadden, a primary source of UAF is gate station meter variations which improved significantly at Victoria Square Gate Station".

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas is a member of a number of international industry research organizations, such as the Pipeline Research Council International (PRCI), NYSEARCH (part of the

[11] EB-2017-0102, Exhibit I.B.EGDI.BOMA.21, filed: 2017-07-14
[12] EB-2017-0086, Exhibit N2, Tab 1, Schedule 1, page 12, filed: December 6, 2017
[13] ScottMadden Report, December 2019, page 39

Northeast Gas Association), and HYREADY (an international consortium of companies creating guidelines for preparing natural gas networks for hydrogen injection). This participation allows Enbridge Gas to keep abreast of the latest research in the area of measurement for the gas industry and apply research results to Enbridge Gas's processes and procedures in the area of measurement.

Based on the research led by PRCI relating to diagnostics and reverification intervals for ultrasonic meters, Enbridge Gas was able to optimize reverification intervals of ultrasonic meters. This included setting a 6-year reverification interval for renewed ultrasonic meters and an 8-year reverification interval for ultrasonic meters under Low Intervention Level agreement with TransCanada Energy (TCE). In addition, Enbridge Gas replaced single rotor meters with dual rotor meters, based on PRCI projects on turbine metering, which evaluated auto-adjust and self-checking capabilities of dual rotor turbine meters.

iv. Implement New Practices and initiatives

Enbridge Gas has addressed the recommendations from the UFG Report relating to gate station measurement. The report recommended reviewing meter point changes and exchanging/swapping check meters to evaluate meter bias. Enbridge Gas' Gas Measurement Integrity Team completes extensive data validation, review for completeness and monitoring, as described previously. These activities ensure alignment of check measurement with receipt point metering and trigger required action required if results are outside of acceptable tolerances.

The UFG Report also contained a recommendation to review requests for meter audits. It is routine practice for Enbridge Gas to notify and engage interconnecting parties for measurement maintenance activities, as well as witnessing measurement maintenance activities of interconnecting party's facilities. Furthermore, Enbridge Gas also facilitates requests for audits of interconnecting stations, such as the 2014 audit of Enbridge Gas' Kirkwall station by TCE. Enbridge Gas and TCE also have a Low Intervention Level (G-14) Agreement in place which specifies the frequency of measurement maintenance at Enbridge Gas' interconnections with TCE, in compliance with Measurement Canada requirements.

3.4 <u>OTHERS</u> (*INCL. ACCOUNTING ADJUSTMENTS, COMPANY USE, THEFT, NON-REGISTERING METERS*)

i. <u>Identify and Standardize Best Practices at EGI</u>

Upon amalgamation in 2019, Enbridge Gas continued to maintain separate customer billing systems within the legacy Companies until the recent transition in July 2021 to one consolidated billing system. During the period of time that the legacy Companies retained separate billing systems, there were process and policy alignment initiatives completed that were not constrained by the broader system integration effort. As it relates specifically to UFG, the customer billing teams aligned the processes relating to theft of gas, with nominal changes to process and forms.

A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term. As noted in the UFG Report "Usage estimation variances may be large enough to create an apparent negative UFG volume in a given month or, more rarely, two or three consecutive months. Negative UFG volumes on a monthly basis occur almost exclusively in the shoulder and summer months, are low in relation to total UFG volumes, and generally reverse or correct themselves within a one-year period".[14]

There have also been alignment efforts relating to the accounting for UFG. The UFG Report notes that "Presently, LUG adjusts for line pack in its calculations of UFG. In December 2019, Enbridge plans to adjust for line pack in its calculation of UFG."[15] Since the filing of the UFG Report, line pack is now included in the LEGD Unaccounted for Gas Variance Account (UAFVA) calculation, which is filed annually as part of the annual earning sharing proceeding.

ii. <u>Document Data/Processes/Studies related to monitoring and managing UFG</u>

N/A

---

14 ScottMadden Report, December 2019, page 44
15 ScottMadden Report, December 2019, page 46

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

N/A

iv. Implement New Practices and initiatives

The UFG Report noted that the Legacy Companies measure, record and account for Company use on a monthly basis[16]. Enbridge Gas has continued to refine the tracking and recording of company use. Since 2019, gas used in company-owned vehicles is also included in the calculation of company use, which has reduced the amount of UFG recorded associated with that gas use.

4.0 SUMMARY

Since 2019, Enbridge Gas has actively addressed the recommendations outlined in the UFG Report. In addition to a number of specific recommendations, ScottMadden also recommended to identify and standardize "best practices" across the legacy Companies, document data, processes and studies related to monitoring and managing UFG, and investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG". This progress report demonstrates the actions taken for each source of UFG to address the recommendations laid out by ScottMadden.

As noted in EB 2019-0194, Enbridge Gas will provide further information in the upcoming rebasing proceeding regarding subsequent efforts to address the UFG Report's recommendations and other activities to address UFG and how these measures have impacted Enbridge Gas's UFG. Enbridge Gas will also present a proposal for consistent forecasting of UFG across its full service area and will report actual UFG results, segregated by rate zone and activity (distribution, transmission, storage) using the most recent historical information available.

[16] ScottMadden Report, December 2019, page 42