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October 15, 2020

BY RESS, EMAIL AND COURIER

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

Dear Ms. Long:

Re: Enbridge Gas Inc.
Ontario Energy Board File No.: EB-2020-0091
Integrated Resource Planning Proposal – Additional Evidence

Pursuant to the Ontario Energy Board's ("OEB" or "Board") Procedural Order No. 4,[1] and consistent with Enbridge Gas Inc.'s ("Enbridge Gas") submission to the OEB of July 29, 2020 describing the nature of additional evidence it intended to file to assist the OEB in addressing the issues on the Issues List set out in Schedule A of the Board's Procedural Order No. 2 and in developing its Integrated Resource Planning ("IRP") framework for Enbridge Gas,[2] enclosed is the Additional Evidence of Enbridge Gas.

Enbridge Gas is seeking OEB approval of its proposed IRP process and approach to treat IRP alternatives ("IRPA") in a similar manner as new natural gas facility infrastructure.

Enbridge Gas's Additional Evidence will be made available on Enbridge Gas's website at: https://www.enbridgegas.com/Regulatory-Proceedings.

If you have any questions, please contact the undersigned.

Sincerely,

[original signed by]

Adam Stiers
Technical Manager, Regulatory Applications

c.c.: D. Stevens (Aird & Berlis)
M. Parkes (OEB Staff)
M. Millar (OEB Counsel)
EB-2020-0091 (Intervenors)

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[1] Procedural Order No. 4 was dated August 20, 2020.
[2] Procedural Order No. 2 was dated July 15, 2020.

INTEGRATED RESOURCE PLANNING PROPOSAL

1. The purpose of this evidence is to provide an overview of the Enbridge Gas Inc. ("Enbridge Gas" or the "Company") Integrated Resource Planning Proposal (the "IRP Proposal") in support of establishing an Integrated Resource Planning ("IRP") framework to guide Enbridge Gas's assessment of Integrated Resource Planning Alternatives ("IRPAs") relative to other facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers.[1] In addition, consistent with the Company's letter of July 29, 2020,[2] this evidence provides: (i) a summary of historical Ontario Energy Board ("OEB" or "Board") directives, findings and recommendations regarding IRP and Enbridge Gas's ongoing actions to comply with the same; (ii) an illustrative IRP process plan detailing how IRP will preferably be integrated into system planning processes/activities at Enbridge Gas going forward; and (iii) an updated jurisdicational review by ICF of advancements and treatment of natural gas IRP in other jurisdictions since the completion of the IRP Study.[3] Given the depth and breadth of the Updated Jurisdictional Review completed by ICF, it has been attached separately as Appendix A to this evidence. Overall, ICF found that there has been little progress on implementation of IRP across North America, apart from New York State, since 2018.[4]

[1] Enbridge Gas was formed by the amalgamation of Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") (together the "Utilities") on January 1, 2019 pursuant to the Ontario Business Corporations Act, R.S.O. 1990, c. B. 16. Enbridge Gas carries on the business of distributing, transmitting and storing natural gas within Ontario.
[2] EB-2020-0091, Enbridge Gas Letter – Integrated Resource Planning Proposal Additional Evidence, July 29, 2020, p. 1.
[3] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020,.
[4] Appendix A, ICF IRP Jurisdictional Review FINAL REPORT, p. 11.

2. Enbridge Gas continues to learn from its internal planning groups, stakeholders, and other jurisdictions as information is shared and experience is gained regarding IRP and how it might be integrated into Enbridge Gas processes. The Company anticipates that this is the start of a constructive dialogue with the OEB and stakeholders, the end result of which will be an appropriate and efficient IRP framework for Enbridge Gas that meets the firm energy needs of the Company's customers in a safe and reliable manner while also encouraging and facilitating (in part) Enbridge Gas's energy transition. As such, this IRP Proposal is intended to be supplemental to the evidence filed as part of Enbridge Gas's 2021 Dawn Parkway Expansion Project and Integrated Resource Planning Proposal and ICF's IRP Study.[5] Enbridge Gas has continued to build upon its natural gas planning expertise and accountabilities as well as its commitment to continuous improvement in refining its approach to IRP since 2018.

3. Enbridge Gas requests that the OEB determine that the framework direction set out within this IRP Proposal is reasonable and appropriate. Approval of the IRP Proposal will enable Enbridge Gas to create actionable IRP plans to support deferment, avoidance or reduction of future infrastructure requirements and to gain important implementation experience. When a need is identified in the planning process, it will be assessed to determine the appropriateness of developing IRPAs to address it. This approach will ensure that Enbridge Gas has adequate lead time to fully assess, put forward to the OEB and verify the effectiveness of IRPAs to address peak period demands, deferring or reducing the need to construct facility alternatives. Where approvals are required in relation to IRPA(s)-specific spending, cost recovery, ownership or other items, Enbridge Gas will seek separate approval from the OEB, as appropriate.

[5] EB-2019-0159, 2021 Dawn Parkway Project, Exhibit A, Tab 13.

4. This evidence is organized as follows:

1.0 <u>Background</u>

5. Enbridge Gas has a track record and reputation for being responsive to its customers' needs and innovative in its approach to system operation, regulatory strategy and energy efficiency programming. In addition, Enbridge Gas has a host of important undertakings that show without a doubt the Company's commitment to responsibly meeting the energy needs of its customers. First and foremost is the Company's strong record for safely and reliably delivering natural gas to Ontario homes, businesses and institutions. Beyond its safety record, Enbridge Gas has also: (i) been a leader in North America and dominant force in Ontario in achieving demand side management ("DSM") energy and bill savings for the past two and a half decades; (ii) long optimized its rate design in order to offer interruptible services to its customers and reflected utilization of those services for system planning purposes; (iii) developed and operates Canada's largest integrated underground natural gas storage facility in Ontario, alleviating the need to construct alternative facilities to serve the peak period demands of Ontario consumers and creating one of North America's most liquid natural gas trading hubs (the Dawn Hub); and (iv) been at the forefront of developing renewable fuel alternatives (green fuels) to conventional energy in Ontario. Enbridge Gas has proven itself to be responsive to major market trends, its customers' interests and governmental/regulatory policies and directives every step of the way.

6. Addressing peak demand in a very targeted manner is the contemporary understanding of IRP. However, E.B.O. 169-III was held in 1992 to conceptually address IRP and formed the basis for Enbridge Gas's incentive-based annually focused DSM framework. Although the Board did not continue with the review of the Utilities' supply-side policies, and the subsequent combination of DSM and supply-side management,[6] Enbridge Gas has none-the-less been diligently and successfully providing broad-based, open access DSM programs to customers to reduce their annual energy use for decades. In fact, since 1995, Enbridge Gas has saved its customers 30 billion lifetime m^3 of natural gas and 56.2 million tonnes of greenhouse gas emissions, the equivalent of taking 12.2 million cars off the road for a year. These significant natural gas savings across almost all rate classes has also provided passive infrastructure investment savings by reducing demand in a broad-based context. And while DSM – appropriately underpinned by its own distinct framework - has evolved as experience has been gained, it is anticipated to continue to be essential in continuing to reduce the natural gas usage and energy bills of Enbridge Gas customers for years to come while also continuing to passively mitigate infrastructure needs over time through reduction in annual demand.[7]

7. It was during Enbridge Gas's (EGD) GTA Project (EB-2012-0451) proceeding that the concept of IRP was once again raised, with the Board finding in its Decision that:[8]

[6] E.B.O. 169-III A REPORT ON THE DEMAND-SIDE MANAGEMENT ASPECTS OF GAS INTEGRATED RESOURCE PLANNING, July 23, 1993, p. 4.
[7] The current 2015-2020 Demand Side Management (DSM) Framework for Natural Gas Utilities (EB-2014-0134) ("2015-2020 DSM Framework") was issued by the Board on December 22, 2014 and subsequently extended into 2021 as part of Enbridge Gas's 2021 DSM Plans proceeding (EB-2019-0271).
[8] EB-2012-0451, OEB Decision and Order, January 30, 2014, p. 46.

> …in light of the evidence presented, the Board concludes that further examination of integrated resource planning for gas utilities is warranted. The evidence in this proceeding demonstrates that the following issues should be examined:
>
> - The potential for targeted DSM and alternative rate designs to reduce peak demand
> - The role of interruptible loads in system planning
> - Risk assessment in system planning, including project prioritization and option comparison
> - Shareholder incentives
>
> There will undoubtedly be other issues as well. The Board notes that this review is particularly timely given the recent provincial Long Term Energy Plan. Further information on how the Board will examine gas integrated resource planning will be released in due course.

While awaiting further direction from the Board, Enbridge Gas began the process of reviewing and understanding IRP, proactively taking a number of steps in this regard prior to the development of the 2015-2020 DSM Framework, including increased internal information exchange and a review of various planning processes to improve connectivity and understanding between some of the Company's supply and demand-side personnel. Enbridge Gas also conducted an Avoided Distribution Cost Study to ensure that the benefits of avoided distribution costs were accounted for in the avoided costs used in the Total Resource Cost Test ("TRC") to screen DSM programs,[9] thus ensuring that the benefits of passive deferral or reduction of infrastructure were being captured.

8. In its 2015-2020 DSM Framework, the Board requested that the Utilities conduct a study to be filed no later than the DSM Mid-Term Review, as well as propose a

[9] This Avoided Distribution Cost study was filed as part of the EGD 2015-2020 DSM Plan; EB-2015-0049, Exhibit C, Tab 1, Schedule 1.

preliminary transition plan that outlines how the Utilities would begin to include DSM as part of their future infrastructure planning efforts.[10]

9. As part of the OEB's Mid-Term Review of the 2015-2020 Demand Side Management (DSM) Framework for Natural Gas Distributors (EB-2017-0128/0127) (the "Mid-Term Review"), EGD and Union filed a joint Transition Plan and IRP Study (Executive Summary) completed by ICF Canada ("ICF").[11] As part of the IRP Study, ICF identified outstanding policy issues and concluded that:[12]

> Changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce facility investments.

ICF went on to explain that these changes would include:[13]

> Cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks. Approval to invest in, and recover the costs of the AMI necessary to collect hourly data on the impacts of DSM programs and measures. Changes in the approval process for DSM programs to be consistent with the longer lead time associated with facilities planning. Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facility investments. Guidance on cross-subsidization and customer discriminations inherent in geotargeted DSM programs that do not provide similar opportunities to all customers. Guidance on how to treat conflicts between DSM programs designed primarily to reduce investment in new infrastructure and DSM programs designed to reduce carbon emissions or

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[10] 2015-2020 DSM Framework, p. 36.
[11] EB-2017-0128, Enbridge Submission, January 15, 2018, Appendices D and E. Enbridge Gas subsequently filed the full IRP Study: (i) as part of its responses to interrogatories in its Bathurst leave to construct proceeding, EB-2018-0097, Exhibit I.EGDI.SEC.1, Attachment 1, October 11, 2018; and (ii) as part of this IRP Proposal proceeding, EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020.
[12] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. 167.
[13] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. 168.

improve energy efficiency. Guidance on how to treat uncertainty associated with energy-efficiency programs outside the control of the Gas Utilities that impact peak hour and peak day demand.

10. On November 1, 2019, as part of its 2021 Dawn Parkway Expansion Project and Integrated Resource Planning Proposal application (EB-2019-0159) ("2021 Dawn Parkway Project"), Enbridge Gas filed an Integrated Resource Planning Proposal ("2019 IRP Policy Proposal") "…in support of establishing an IRP framework to guide Enbridge Gas's assessment of IRPAs relative to other facility and non-facility alternatives to serve the forecasted needs of Enbridge Gas customers."[14] Enbridge Gas requested that the OEB make a determination that its IRP Proposal was reasonable and appropriate in order to establish the necessary IRP policy framework required to create actionable IRP plans to support future deferment, avoidance or reduction of infrastructure requirements.

11. Enbridge Gas's IRP Proposal explained that the Company brought forward its Application as a result of prior direction from the OEB: (i) to put forward an IRP Study outline as part of the EGD rate zone's 2015-2020 DSM Plan;[15] (ii) to jointly (EGD and Union) complete a study scope for IRP that takes into consideration the enhancements suggested by intervenors and expert witnesses who participated in the review of 2015-2020 DSM Plans for the EGD and Union rate zones (EB-2015-0029/0049);[16] (iii) to initiate the IRP Study and "…submit a methodology for assessing the appropriate role for DSM as part of infrastructure planning at the mid-term DSM review."[17]; (iv) to develop more rigorous, robust and comprehensive procedures to ensure conservation and energy efficiency opportunities can be

[14] EB-2019-0159, 2021 Dawn Parkway Project, Exhibit A, Tab 13, p. 1.
[15] 2015-2020 DSM Framework, p. 36.
[16] EB-2014-0134, Filing Guidelines to the 2015-2020 DSM Framework, December 22, 2014, pp. 40-41.
[17] EB-2015-0029/0049, OEB Decision and Order, January 20, 2016, p. 83.

reasonably considered as alternatives to future capital projects;[18] and (v) to provide sufficient and timely evidence of how traditional DSM has been considered as an alternative at the preliminary stage of project development as part of applications for leave-to-construct ("LTC") facilities.[19]

12. In its Procedural Order No. 1 in the 2021 Dawn Parkway Project proceeding dated January 30, 2020, the OEB determined that Enbridge Gas's IRP Proposal would be heard separately from the 2021 Dawn Parkway Project as it "…raises issues of broad applicability that are best dealt with outside of the context of a project-specific Leave to Construct proceeding."[20] The OEB subsequently issued a Letter and Notice of Hearing for Enbridge Gas's IRP Proposal on April 28, 2020, inviting applications to intervene and letters of comment from parties.

13. On May 21, 2020, the OEB issued Procedural Order No. 1 ("PO No. 1") in the IRP Proposal proceeding, granting twenty-one (21) parties intervenor status (in addition to OEB Staff),[21] clarifying that the IRP Proposal proceeding is not intended to assess the merits of specific projects and seeking input on OEB Staff's Draft Issues List. PO No. 1 also advised that OEB Staff would produce expert evidence that would review the experience of natural gas IRP in other jurisdictions, such as New York State, and its relevance to Ontario.

14. On July 15, 2020, following its review of submissions from Enbridge Gas and intervenors on OEB Staff's Draft Issues List, the OEB issued its Decision on Issues List and Procedural Order No. 2 ("PO No. 2"). PO No. 2 defined the scope of the IRP

[18] Mid-Term Review, Report of the Board, November 29, 2018, pp. 6, 20-21.
[19] EB-2018-0097, OEB Decision and Order, January 3, 2019, p. 6.
[20] EB-2019-0159, OEB Procedural Order No. 1, January 30, 2020, p. 2.
[21] A late request for intervenor status submitted by EPCOR Natural Gas LP was subsequently approved by the OEB as part of Procedural Order No. 2 increasing the number of intervening parties in this proceeding to twenty-two (22), excluding OEB Staff.

Proposal proceeding as including "…broad consideration of the definition and goals of IRP, and the process and approach for incorporating IRP into Enbridge Gas's system planning process, including consideration of alternatives to Enbridge Gas's IRP Proposal."[22] PO No. 2 also established a final Issues List, directed Enbridge Gas to file the IRP Study completed by ICF with the OEB and invited Enbridge Gas and intervenors to advise the OEB of any additional evidence that they intend to file in the proceeding, including a description of the nature of that evidence.

15. On July 29, 2020, in accordance with PO No. 2 Enbridge Gas filed a letter with the OEB describing the nature of additional evidence it intended to file to assist the OEB in addressing the issues on the Issues List set out in Schedule A of PO No. 2 and in developing its IRP framework for Enbridge Gas (this evidence). Enbridge Gas advised that its additional evidence would build upon its original IRP Proposal and ICF's IRP Study and would provide:[23]

> (i) a summary of historical OEB directives, findings and recommendations regarding IRP and Enbridge Gas's ongoing actions to comply with the same, in support of Issue 2; (ii) an updated jurisdictional review by ICF of advancements and treatment of natural gas IRP in certain other jurisdictions since the completion of the IRP Study, in support of Issues 1 and 5; and (iii) an IRP Process Plan that details how IRP would preferably be integrated into system planning activities at Enbridge Gas going forward (for illustrative purposes), in support of Issues 2, 6 and 10.

16. Enbridge Gas's letter went on to request an extension to file its additional evidence, from September 10, 2020 to October 15, 2020 and that, as the applicant, it be afforded the opportunity to file responding evidence to the evidence filed by OEB Staff and intervenors. On July 31, 2020, the OEB issued Procedural Order No. 3 ("PO No. 3") which granted Enbridge Gas's requested extension to file additional

[22] EB-2020-0091, PO No. 2, July 15, 2020, p. 2.
[23] EB-2020-0091, Integrated Resource Planning Proposal Additional Evidence, July 29, 2020, pp. 1-2.

evidence, modified the remaining procedural timeline to provide OEB Staff and intervenors a similar extension to file their respective evidence, and advised that the OEB was prepared to provide Enbridge Gas the opportunity to file responding evidence. Enbridge Gas was ordered to notify the OEB of its intention to file responding evidence following receipt of letters from intervenors advising of their intention to file evidence and describing the nature of that evidence.

17. On August 12, 2020, in accordance with PO No. 3 Enbridge Gas filed a letter in response to the submissions of OEB Staff, Environmental Defence ("ED") and Green Energy Coalition ("GEC") and the Federation of Rental-housing Providers of Ontario ("FRPO") regarding their respective intentions to file evidence in the IRP Proposal proceeding. In its letter, Enbridge Gas advised the OEB of its intention to file responding evidence should the OEB allow the evidence proposed by these parties, and objected to FRPO's proposal to submit evidence related to current natural gas market and flow dynamics in Ontario on the basis that it is not directly relevant to the OEB's review of Enbridge Gas's application or the Board's development of an IRP framework for Enbridge Gas. Enbridge Gas's objection was supported by the fact that its IRP Proposal does not seek OEB approval to implement specific IRPAs or to recover the costs associated with investment in specific IRPAs and Enbridge Gas does not intend to seek any such IRP-specific approval from the Board as part of this proceeding.

18. On August 20, 2020, the OEB issued Procedural Order No. 4 ("PO No. 4") acknowledging and accepting the proposals to file evidence submitted by Enbridge Gas, GEC/ED and OEB Staff. PO No. 4 also confirmed that the OEB considers supply-side alternatives to be pertinent to IRP. However, the OEB expressed concerns regarding the relevance of FRPO's proposed evidence to the IRP Proposal proceeding including that it might duplicate matters previously considered as part of

Enbridge Gas's five-year natural gas supply planning (Consultation to Review Natural Gas Supply Plans) proceeding (EB-2019-0137). Further, regarding FRPO's request on the timing of interrogatories, the OEB advised that it does not intend to provide an opportunity for discovery prior to filing of evidence and that all parties will be granted an opportunity for discovery following initial filing of evidence and Enbridge Gas's responding evidence. The OEB also directed Enbridge Gas to provide details on the extent to which its additional evidence would address the approach to supply-side alternatives as part of IRP, which Enbridge Gas did via submission to the OEB on August 27, 2020.

19. In its August 27 submission, Enbridge Gas stated that as part of its proposed IRP process plan it would describe how and when:[24]

> (i) system capacity constraints are identified; and (ii) facility and non-facility alternatives (including IRP alternatives) that could address such constraints will be assessed.

Enbridge Gas went on to explain that:

> As Enbridge Gas considers long-term supply-side alternatives to be IRPAs it intends to assess them together with all other facility and non-facility alternatives following the identification of system capacity constraints.

Enbridge Gas's August 27 submission also reiterated its concerns regarding FRPO's proposed evidence and stated that consideration and approval of specific IRPA's (including long-term supply-side solutions) is more appropriately dealt with in future IRPA or LTC applications that consider various facility and non-facility alternatives to address identified system constraints/needs.

[24] EB-2020-0091, Enbridge Gas Letter: Details of Additional Evidence, August 27, 2020, p. 1.

20. On September 15, 2020, the OEB issued Procedural Order No. 5 (“PO No. 5”) which denied FRPO’s request to file its proposed evidence and clarified that supply-side alternatives (both short and longer-term) are pertinent to IRP and therefore within the scope of the IRP Proposal proceeding. PO No. 5 confirmed that the timelines set out in PO No. 4 would largely remain unchanged, including: (i) for this additional evidence from Enbridge Gas (to be filed by October 15, 2020); (ii) for the expert evidence commissioned by OEB Staff (to be filed by November 12, 2020); (iii) for intervenor evidence from GEC/ED (to be filed by November 19, 2020); (iv) for Enbridge Gas to notify the OEB if it determines that it will not file responding evidence (to be filed by November 26, 2020); and (v) for Enbridge Gas’s responding evidence (to be filed by December 11, 2020).

2.0 IRP Illustrative Process Plan

21. Enbridge Gas intends to integrate IRP into its existing planning processes/activities. The following evidence provides an illustrative process plan explaining how Enbridge Gas will incorporate IRP into its processes including stakeholdering, the identification of a need, consideration and analysis of IRP in parallel with existing facilities planning and the implementation of an IRPA. A more detailed discussion of the IRP process can be found at Section 3.0 below.

22. Enbridge Gas’s IRP Proposal and illustrative process plan are underpinned by the following Guiding Principles:

i. Reliability and Safety - In considering IRPAs as part of system planning processes, Enbridge Gas’s system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas’s customers must remain of paramount importance.

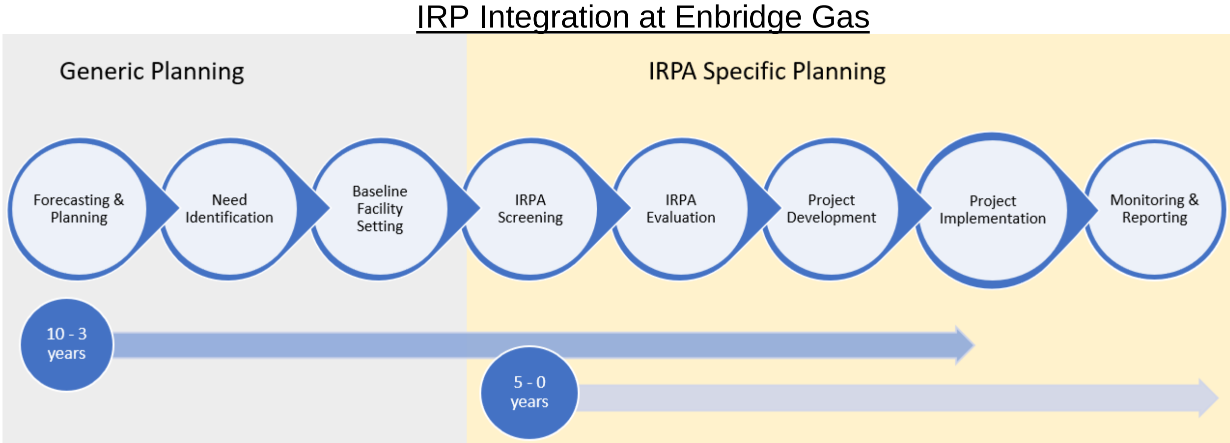
ii. Cost Effectiveness – IRPAs must be cost-effective (competitive) compared to other facility and non-facility alternatives.

iii. Public Policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, where appropriate.

iv. Optimized Scoping - Recognizing that reviewing IRPAs for every forecasted infrastructure project would be extremely time intensive, binary screening should be undertaken to confirm which forecast need(s) should undergo an IRP assessment. Screening criteria are suggested later in this evidence.

23. In this evidence, Enbridge Gas proposes an IRP process plan that takes into account its existing forecasting and system planning processes which provide critical input to the development of a fulsome Asset Management Plan ("AMP") designed to meet the forecasted firm contracted peak period demands of customers. As set out in Figure 2.1, following OEB approval of an IRP framework, Enbridge Gas will incorporate its IRP Proposal into its existing planning processes and review qualifying facility needs for potential IRPAs.

Figure 2.1:
IRP Integration at Enbridge Gas



24. Forecasting and Planning - Enbridge Gas regularly completes a long-term demand forecast and planning process that identifies specific needs across its system. The objective of demand forecasting and planning processes is to amass input to develop insights into the future system constraints/needs that the Company expects to materialize, both in terms of their magnitude and timing, in order to ensure that it has sufficient capacity to serve those needs and fulfil its obligation to serve the firm contracted peak period demands of its customers. Enbridge Gas arrives at its annual demand forecast through the completion of an in-depth analysis that focuses on key factors impacting demand, including: (i) existing firm contracted demand; (ii) customer growth (gleaned through its sales, stakeholdering and consultation activities);[25] (iii) normalized weather; (iv) DSM impacts; (v) system design day requirements; (vi) customer consumption patterns; (vii) economic outlooks/indicators; and (viii) current public policy.

25. Need Identification – When Enbridge Gas determines that its current facilities cannot balance the peak demand forecast with existing system facilities that can deliver the forecasted volumes safely and reliably, a system need is identified.

26. Baseline Facility Setting – A second step following identification of a system need is to understand the baseline facility that would have been suggested in the absence of the IRP process. It is necessary to know what that baseline facility is so that the IRPA(s) can be compared against that solution.

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[25] In accordance with the OEB's Storage and Transport Access Rule, Enbridge Gas conducts new capacity Open Seasons soliciting market interest for additional firm ex-franchise transmission services and Reverse Open Seasons to afford existing ex-franchise shippers the opportunity to turn-back contracted capacity (supporting system efficiency and rational expansion). The frequency of new capacity Open Season's and Reverse Open Seasons is somewhat irregular as it is driven by a combination of: (i) external market variables such as complementary Open Seasons offered by upstream or downstream transportation providers, or expressions of interest from market participants; and (ii) internal system planning activities. Accordingly, and in contrast to typically linear in-franchise customer demand growth, ex-franchise customer demand growth tends to be non-linear, and thus less predictable.

27. IRPA Screening - Following the identification of a system need, Enbridge Gas will review the need relative to the screening criteria as discussed below. If the system need meets the screening criteria, Enbridge Gas will then analyze any IRPA(s) that could meet the capacity requirements of the system need.

28. IRPA Evaluation - If the screening of the system need indicates IRPA(s) may be reasonable to assess, then Enbridge Gas will undertake a two-stage evaluation of IRPAs as outlined in its 2019 IRP Policy Proposal. The first stage is the identification of potential IRPA(s) and the testing of the reliability of the IRPA(s). The second stage is the evaluation of the IRPA(s) including an economic assessment and consideration of the Guiding Principles.

    i. First Stage – Enbridge Gas will review the facility need for potential IRPA(s) that could be used to defer, avoid or reduce the new facility infrastructure. Once that review is complete on the basis of the 2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study reference points and other data developed over time as benchmarks for possible savings from demand response,[26] it will be clear whether an IRPA will be a viable option. Part of the assessment of IRPAs will be to consider how reliable the savings are from various IRPAs, recognizing that this is important for appropriate costing and planning. For example, in the IRP Study, ICF noted that enhanced energy efficiency may need to target a higher savings level than is desired and suggested a target of 121% of the desired savings level.[27] Enbridge Gas notes that other jurisdictions capture this concept by utilizing a derating factor for the

[26] https://www.oeb.ca/sites/default/files/2019_Achievable_Potential_Study_20191218.pdf
[27] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. ES-18.

savings of alternatives.[28] A derating factor is a reduced effectiveness rate ascribed to an alternative's savings value to capture its inherent risks. Enbridge Gas anticipates that derating factors will be refined as experience with various alternatives in Ontario grows, technologies and solutions are tested and when ultrasonic metering is in place to provide more certain data.

ii. Second Stage – Enbridge Gas will compare the facility alternative and selected IRPA(s) on an economic basis and will also consider one or several alternate IRPA portfolios based on the complexity and size of the system need. In addition, Enbridge Gas will assess the IRPA(s) for safety and reliability and alignment with public policy per the Guiding Principles above. Further discussion on how Enbridge Gas will go about completing an economic test comparing facility and non-facility alternatives follows in Section 3.0 below.

29. Project Development - If an IRPA(s) is the most economical solution to meet the system need and it satisfies the Guiding Principles, Enbridge Gas will incorporate that IRPA(s) in the AMP for inclusion into its broader planning activities, stakeholder touchpoints and implementation at the appropriate time. Enbridge Gas will ensure that all details related to this IRPA(s) and the need that it is intended to address will be fully refined in this step. Following the identification of an IRPA(s) and its inclusion in the AMP, Enbridge Gas will begin preparations to develop and subsequently file an application and supporting evidence with the OEB for approval. Enbridge Gas will continue to monitor the need for the IRPA(s) as part of its planning activities until such time that the project is implemented.

[28] Appendix A, ICF IRP Jurisdictional Review FINAL REPORT, p. 69.

30. Project Implementation – Enbridge Gas will file IRPA applications that will lay out respective anticipated savings or peak period impacts (on an hourly basis for distribution system assets and on a daily basis for transmission and storage system assets) together with their respective associated costs and ownership/operationalization arrangements. IRPA applications will seek approval to spend and subsequently recover costs associated with investing in an IRPA(s), including: design, administration, implementation, monitoring and reporting. As is the case with traditional LTC applications, Enbridge Gas intends to consult with any impacted landowners, municipalities, First Nations, Indigenous groups and other affected stakeholders prior to filing its IRPA application with the OEB. If the project is approved, then the IRPA would be implemented in the field.

31. Monitoring and Reporting – Following the implementation of an IRPA(s), the effectiveness of the alternative in meeting the identified need will be carefully monitored to ensure the identified system constraints/needs are being sufficiently resolved. Enbridge Gas will provide an annual report of IRPA effectiveness to the OEB as part of either its annual Rates application or Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, or as otherwise directed by the Board. If the IRPA is not meeting the identified need, Enbridge Gas will propose corrective action in its report which may include, but not be limited to, proposals to implement additional IRPAs or a new facility build to meet the need.

32. Given that natural gas IRP is still relatively nascent and forms an innovative approach to meeting natural gas facility needs, the process outlined above will necessarily be refined over time as experience is gained and opportunities for improvement in IRPA design and implementation are identified.

3.0 IRP Proposal

33. The following section of evidence provides further details of the IRP Illustrative process summarized above.

34. Enbridge Gas is committed to considering IRPAs, as appropriate, immediately following the identification of a system constraint/need. The following IRP Proposal sets out the considerations that will influence how Enbridge Gas assesses and implements IRPAs that are determined to be preferred alternatives to address forecasted customer demand and related system constraints/needs. In the subsections that follow, Enbridge Gas details each component of its supplemental IRP Proposal.

Goal of IRP for Enbridge Gas

35. Building off the previous 2019 IRP Policy Proposal, for Enbridge Gas, IRP is a planning strategy underpinned by the Guiding Principles discussed in section 2.0, to consider facility and non-facility alternatives in tandem which address long-term system constraints/needs such that an optimized and economic solution is proposed to meet the identified constraint or need. Consistent with the Guiding Principle of Cost Effectiveness, given that the least cost option is a central driver for selection of either a facility or non-facility solution, the recommended solution should be a lesser cost for customers on-the-whole. However, as pointed out in the IRP Study completed by ICF,[29] this is an important approach that needs to be confirmed by the OEB as it will have a major impact on the development of an IRP framework for Enbridge Gas. For the purposes of this IRP Proposal the remainder of this evidence assumes that the Board will prioritize the most economic (lowest cost) alternative.

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[29] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. ES-37.

Where should IRP be considered?

36. IRPA analysis, which includes a more specific review of alternatives that could be reasonably considered to meet a system constraint/need, is anticipated to involve a detailed and iterative process. If this full IRP planning process was undertaken for every forecasted peak period system constraint/need it would be exceedingly time and resource intensive, resulting in substantial incremental administrative cost burden to ratepayers. To avoid incurring such costs where limited potential value to ratepayers exists, and so that all existing resources are optimized, the first step in assessing the appropriateness of IRPAs to defer, avoid or reduce the need for new facilities is to establish the appropriate scope and scale of system constraints/needs that should qualify for IRPA assessment. Certain basic attributes of facility expansion/reinforcement projects support a binary screening of the relevance of IRPAs, with other attributes being informative (e.g, the estimated project cost), but not providing certainty as to the likely outcome of an IRPA assessment.

37. In Enbridge Gas's 2019 IRP Policy Proposal, there was a table (Table 3.1) that summarized project attributes supporting the relevance of IRPAs. Since the time of that filing, and through its continued learnings about IRP, Enbridge Gas has evolved its thinking around the criteria that would constitute a binary screening for IRP assessment.

38. The following are Enbridge Gas's proposed updated criteria for completing a binary screening for whether an IRP analysis should be considered:

i. Safety – If a facility project designed to meet an identified need is determined to be essential in order to ensure the continued ability to offer safe and reliable service, or to meet an applicable law, it would not be a candidate for IRP analysis. For example, if a line sustains unanticipated damage, it needs to be replaced as quickly as possible to ensure the safety of the community and the broader system as well as to ensure customers' needs continue to be met. The urgent timing and nature associated with most safety-related projects (e.g., requiring replacement of short pipeline segments), including integrity projects, does not allow for the lead times necessary for developing IRPA solutions.

ii. Timing – If a system need must be met in under 3 years, an IRPA cannot be implemented and verified in time, and therefore, an IRP analysis is not prudent.

iii. Project-specific considerations – If a project is being advanced in order to leverage other municipal infrastructure development, or relocation of natural gas infrastructure in a particular corridor (e.g., concurrently with road works or water main replacements) then timing may necessitate the installation of physical infrastructure.

iv. Customer-Specific Builds – If an identified need has been underpinned by a specific customer's clear determination for a facility option and either the choice to pay a Contribution in Aid of Construction ("CIAC"), or to contract for long-term firm services delivered by such facilities, then that project is not reasonable for an IRP analysis.

v. Community Expansion & Economic Development – If a project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not reasonable to conduct an IRP analysis.

What activities/projects (IRPAs) are eligible to be included within an IRP?

39. The goal of an IRPA is to resolve a system constraint/need thereby deferring, avoiding or reducing construction of infrastructure expansion/reinforcement projects (e.g., pipelines). Although Enbridge Gas would like to have the ability to use a broad range of IRPA options to achieve this goal, it recognizes that natural gas options that address peak load are somewhat limited. Enbridge Gas proposes to consider several innovative or high efficiency technologies that may not fit within the current DSM construct such as: residential natural gas heat pumps and Compressed Natural Gas ("CNG"), targeted energy efficiency, supply solutions, green fuels (likely fitting in limited applications at the current time), and demand response. Further, there may be a role for Enbridge Gas, where a well-functioning market does not exist, to include solutions that rely on other energy sources such as geothermal systems.

Innovative Technologies:

Gas Alternatives

40. Natural Gas Air Source Heat Pumps ("NGASHP") are only available for commercial and industrial applications in Canada. However, efforts are currently underway to commercialize the technology for the residential market, potentially by 2023. The efficiency of NGASHPs make them an ideal IRPA candidate. NGASHPs operate at a greater efficiency than traditional natural gas furnaces due to their mode of operation. The efficiency of NGASHPs decreases as ambient tempuratures fall, however, their efficiency should never fall below 100%. A NGASHP uses natural gas to move (pump) thermal energy from a medium, such as the air outside of a building, or the ground beneath a building (geothermal), to where it is needed (e.g., to heat water or for space heating).

41. NGASHPs will be effective at reducing peak day, peak hour and annual demands. In comparison to a traditional natural gas furnace, NGASHPs generate lower temperature heat. NGASHPs would support peak period demand reductions due to an increase in overall heating efficiencies as the proportion of the technology increases in a network of customers. Enbridge Gas expects that significant numbers of customers would need to convert to NGASHPs in order to see measurable peak period demand reductions at scale.

42. CNG has been considered to avoid new infrastructure expansion/reinforcement projects by Enbridge Gas in past LTC applications. In this context, CNG is considered a distribution IRPA and not a gas supply IRPA. Where system constraints/needs are identified, CNG can be injected into a targeted section of the pipeline system experiencing lower than optimal pressures to ensure adequate pipeline pressure control and the continued reliable delivery of natural gas. A CNG solution may also be tailored for use in specific residential, commercial and/or industrial applications. This solution may be able to defer incremental facilities by supplying needed incremental gas volumes, and/or a pressure backstop to vulnerable networks for short periods, which would have the effect of extending the ability of existing assets to support new demands. As such, CNG may not provide a long-term solution for meeting system demands, but instead may serve as a tool for short periods of constraint. Enbridge Gas expects to gain more insight into CNG as a tool, among others, as industry experience with such applications becomes more commonplace. ICF's IRP Jurisdictional Scan notes that ConEd Gas and National Grid have implemented CNG injection facilities for peaking capacity and have expressed a need to continue to plan for future installations.[30]

[30] Appendix A, ICF IRP Jurisdictional Review FINAL REPORT, p. 4.

43. Renewable Natural Gas ("RNG") could be used in place of conventional natural gas for any CNG project, thus rendering the injection greenhouse gas emissions ("GHG") neutral. The ICF IRP Jurisdictional Scan notes that RNG may be cost prohibitive especially as it is compared to new natural gas infrastructure.[31] Instead, the incorporation of an RNG project may provide a supply option (in terms of pressure/volume), arguably making this a gas supply alternative. Enbridge Gas recognizes that although this is being proposed to be included in the menu of IRPAs it may not be a viable solution any time in the near future.

Non-Gas Alternatives

44. Non-gas alternatives have no (or minimal) reliance on natural gas and instead would impact Ontario's electricity system. Non-gas alternatives primarily include electrically powered geothermal heat pump systems and electric air source heat pumps ("EASHP"). In certain situations where natural gas facilities are available, natural gas could be used to provide back-up functionality and resilience to these alternatives.

45. Enbridge Gas notes that it could offer these alternatives if authorized by the OEB, to reduce peak period demand in targeted areas. Should this authorization be granted, these assets would need to be included into rate base or else by investing in such alternatives the Company would be contributing to higher rates for existing customers since they would not receive the moderating advantage of new revenues from customer growth to help offset Enbridge Gas's overall costs.

46. Geothermal installations are applicable to all customer sectors – residential, multi-residential, commercial and industrial. These systems are designed to provide

[31] Appendix A, ICF IRP Jurisdictional Review FINAL REPORT, p. 49.

space conditioning and water heating via the exchange of energy with the earth's surface through a configuration of buried pipes. This energy exchange is facilitated by a ground source heat pump ("GSHP"), most commonly powered by electricity.

47. District energy, also known as a thermal energy system, is designed to supply thermal energy (heating/cooling) to multiple buildings from a central plant or from several interconnected but distributed plants through harnessing and converting various forms of energy (such as natural gas, geothermal, photovoltaic cells, waste heat recovery) into useful thermal energy and distributing it to end-use customers (residential, commercial or industrial) through underground pipes.

48. EASHPs operate on the same basis as NGASHPs, however, the compression and expansion cycles in EASHPs are driven by electrical energy as opposed to natural gas. Similar to NGASHPs, as the ambient temperature falls, the efficiency of EASHPs also decreases, thus increasing electrical consumption. An EASHP's typical minimum efficiency is 100%.[32]

49. Both electric GSHPs and EASHPs provide a solution that could be deployed to mitigate the need to build new infrastructure or to reduce the amount of new infrastructure required. It should be noted that these solutions may also result in unintended and perhaps meaningful consequences to electrical transmission and/or distribution system(s) and their carbon intensity profiles.

50. A power-to-gas ("PtG") plant may also be considered an IRPA. PtG is an effective technological solution that can connect natural gas and electrical infrastructure,

[32] At colder ambient temperatures, NGASHPs operate at a higher efficiency than EASHPs.

enabling dispatchable sources such as solar and wind. The plant can be used to generate and store electrical energy as well as to provide grid stabilization services.

51. During periods of peak electrical demand, stored hydrogen can be used to produce electricity. Furthermore, the hydrogen can also be injected into natural gas infrastructure to displace traditional natural gas volumes.

Demand Response

52. Demand Response (“DR”) programs seek to adjust the demand for natural gas by influencing end-use consumption instead of adjusting facilities or gas supply. DR includes programs for residential, commercial and industrial customers which are designed to incent or oblige the customer to reduce or shift energy usage during peak periods. DR solutions within the natural gas sector are not as common as in the electrical sector and can be varied in nature depending on customer mix.

53. A distinction between DR programs for various customers classes is determined by the customer’s qualification based on consumption as well as preference for any particular rate class and the contractual terms of that rate.

54. Customers that are part of the General Service rates, typically residential customers and some smaller commercial customers, have consumption patterns that are dominated by space heating on peak days. These customers are additionally not bound by contract minimums or other factors that can limit the amount of demand reduction during a DR event. For customers that have additional contractual requirements, typically larger commercial and industrial customers, there are other factors that can mitigate their achievable demand reduction. For example, larger industrial or commercial customers may have technical limitations that can limit their

ability to shift or reduce peak demand, or they may not have the risk appetite to modify their processes to enable peak shifting.

55. Residential DR programs can be geotargeted to a particular area or group of customers and possess the ability to be quickly enhanced with increased incentives to drive enhanced outcomes. DR programs can have several attributes. They can be Utility Controlled Programs or Customer Controlled (or Behavioural) Programs and they can be fully voluntary, or they can be contractually binding. DR programs have been a staple in the electricity market given the diversity of drivers of peak load – many of which are discretionary in nature – as well as other electricity market attributes such as the existence of Time of Use ("TOU") Rates.

56. Enbridge Gas notes that there have been recent examples of natural gas DR programs, and that the results of those programs are still being analyzed in order to draw meaningful conclusions. The Company feels that although early reports on natural gas DR programs have been mixed,[33] there is value in exploring these programs as an IRPA. Enbridge Gas will keep a close eye on DR pilots in the residential space.

57. Contract Rate customers that elect to obtain gas service through a firm contract rate are typically bound by volumetric requirements reflecting their historic consumption patterns. Thus, their contracted volumes are always reserved on the system to ensure that they can access them at any time, as needed.[34] Enbridge Gas customers can contract for both a firm service level and an interruptible ("IT") service level. Typically, an IT service level supplements the customer's firm (base load) demand to provide incremental volumes during instances of peak demand if capacity

[33] https://www.socalgas.com/save-money-and-energy/rebates-and-incentives/smart-therm
[34] Under normal operating conditions, not instances of force majeure or emergency.

is available on the system when IT services are desired. The reason for this design, in-part, is to optimize the efficiency of Enbridge Gas's system. Interruptible contract volumes are not included in system design day volumes. In the event of a curtailment, customers must comply with their contract terms and only use their firm services as there is not the firm capacity required to meet their interruptible needs.

58. In Ontario, Contract Rate customers have had the option of firm contracts and interruptible contracts for decades. In fact, Enbridge Gas's commercial and industrial customers have been moving away from interruptible rates for their natural gas volumes as they value certainty of supply over the cost reduction. Given the existing options available to customers today, it is unlikely that significant new DR solutions exist for Contract Rate customers in Ontario. However, Enbridge Gas will continue to monitor customer trends and information in DR solutions generally to ensure that if it becomes a viable IRPA for such customers in the future it is given due consideration.

Enhanced Targeted Energy Efficiency

59. Enhanced Targeted Energy Efficiency ("ETEE") is a means to address peak demand reductions in a particular geographic area and consists of supplementing existing traditional DSM programs (which target annual volume reductions and bill reductions) with additional spending, and/or designing and implementing new energy efficiency programs that are not part of the current DSM plan.

60. When compared with other IRPAs, leveraging existing DSM programs may prove to be a cost-effective and efficient means to address peak period demands, recognizing that various factors would still need to be taken into consideration to design and implement an effective solution. For example, research would need to be done to understand what level of customer incentive is required to drive targeted

outcomes from the end-use customer. In its IRP Jurisdictional Scan, ICF noted that for ConEd, the use and magnitude of what they call ‘incentive kickers’ are an important component for the success of such energy efficiency programs.[35] In addition, if expectations for an enhanced energy efficiency program are quite large in magnitude, channels to market and capacity to meet the targets may need to be strengthened and grown. It is anticipated that over time, these elements will become more well understood and timelines can be better predicted for this IRPA.

61. While all traditional DSM measures positively impact daily peak period demands to varying degrees, not all necessarily have a positive impact on hourly peak demand. An example includes space heating controls for temperature setback, where the temperature setpoint is reduced overnight resulting in lower heating consumption and annual bills. However, at the end of the setback period, building setpoints are returned to daytime levels which may result in higher peak hourly flows on the natural gas system. This reality may require a prioritization of the differing goals and objectives of DSM and IRP in some instances.

62. Contrary to traditional DSM, which is focused on ensuring broad-based participation, ETEE is focused on programs that achieve a high penetration in a specific geography to reduce peak period system demands corresponding to an identified system constraint/need. This fundamental difference will lead to ETEE requiring much greater levels of funding per unit of energy savings targeted when compared to what traditional DSM would expend in that specific geography absent IRP requirements.[36]

[35] Appendix A, ICF IRP Jurisdictional Review FINAL REPORT, pp. 27-28.
[36] Appendix A, ICF IRP Jurisdictional Review FINAL REPORT, p. 3.

63. Given that the Board has approved funding in Enbridge Gas's 2015-2020 DSM Plans (EB-2015-0029/0049) to meet the goals and objectives of the 2015-2020 DSM Framework,[37] Enbridge Gas expects that separate funding and resources would be allocated to meet the differing goals and objectives of an IRP framework for Enbridge Gas.[38] This would include covering the cost of implementation, tracking and monitoring the impacts of ETEE and/or other IRPAs. It is expected that where the goals and objectives of a DSM Framework and the IRP framework are complementary, the funding provided could be "stacked" to promote both goals and objectives. As an illustrative example, if an existing traditional DSM program offering provides an incentive of $1,000 to a participant to reduce their annual consumption, IRP funding may provide additional incentives of $500 in a geographically targeted area to drive higher levels of participation and peak period demand reductions for that area.

Gas Supply Alternatives

64. When planning to meet in-franchise customers' forecasted demands, Enbridge Gas will consider long-term natural gas supply IRPAs if they meet the Gas Supply Guiding Principles as outlined in Enbridge Gas's 5 Year Gas Supply Plan.[39] As set out in its 5 Year Gas Supply Plan, commercial alternatives such as peaking supply, delivered supply, exchanges and third-party assignments are not considered appropriate to meet long-term gas supply requirements.

65. When evaluating gas supply alternatives, Enbridge Gas balances its gas supply planning principles of reliability, flexibility, diversity and cost-effectiveness, against

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[37] Also, through its approval of Enbridge Gas's 2021 DSM Plans application (EB-2019-0271).
[38] As discussed in paragraphs 74 – 75, Enbridge Gas proposes to capitalize the costs of ETEE as rate base assets, capturing the incremental IRP-related spend associated with successfully achieving peak period reductions distinct from existing DSM programming within its revenue requirement.
[39] EB-2019-0137, Enbridge Gas 5 Year Gas Supply Plan, May 1, 2019, pp. 5-6.

an alternative's ability to provide the requisite capacity.[40] Balancing these factors in evaluating gas supply options allows Enbridge Gas to meet the Board's guiding principles for assessment of the Gas Supply Plan. Enbridge Gas evaluates all viable alternatives regardless of whether there is available capacity, or the alternative requires additional infrastructure, in order to understand the potential of each alternative. At such time that an investment decision is to be made, Enbridge Gas re-evaluates alternatives in order to plan based on current market conditions.

How to determine whether to proceed with an IRPA?

66. Having determined that a future system constraint/need exists and that it meets the criteria identified above, Enbridge Gas will review the potential to resolve the constraint/need using an IRPA. If an IRPA, or IRPAs, can reliably meet the forecasted demands driving the constraint/need in place of new facility expansion/reinforcement projects, then Enbridge Gas will evaluate the IRPA on an economic basis compared to new facilities.

67. Although cost/economics is the primary factor with respect to alternative selection, as set out in the Guiding Principles underpinning Enbridge Gas's IRP Proposal (discussed in section 2.0), there are other factors that may be considered. Given the OEB's role as an economic regulator, economics will normally play a central role in the decision process, even when not the sole determining factor. Reliability is also expected to be an important discussion, in keeping with the OEB's statutory objective of protecting consumers with respect to reliability of natural gas service and Enbridge Gas's obligation to meet the firm contracted peak period demands of its customers. Ultimately, cost/economic evaluation together with consideration of system reliability, safety and sustainability and broadly protecting the interests of

[40] EB-2019-0137, Enbridge Gas 5 Year Gas Supply Plan, May 1, 2019, p. 44.

customers will enable Enbridge Gas and the Board to determine whether it is preferable to proceed with investment in an IRPA.

68. The economic feasibility for IRPAs will be assessed using a Discounted Cash Flow ("DCF") methodology consistent with principles underpinning the Board's E.B.O. 134 and E.B.O. 188. As part of its DCF analysis, Enbridge Gas will include forecast of incremental revenues and an estimate of all direct capital costs associated with the IRPA including an estimate for incremental overheads. Additionally, an estimate for incremental operating and maintenance ("O&M") expenses, municipal property taxes, and income taxes will be included.

69. The IRPA's forecast net cash flows will be discounted using a discount rate equal to Enbridge Gas's incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

70. The project horizon will be set to align with the OEB-approved depreciable life of the infrastructure asset(s) to which the IRPA is being compared.

71. A project will be deemed economically feasible if the resulting Net Present Value ("NPV") of the DCF is zero or greater.

72. If an IRPA can meet the demands of the future system capacity, is more cost-effective than facility alternatives and meets the other important Guiding Principles, then Enbridge Gas will include the IRPA in the AMP as a future potential project.

How will Enbridge Gas proceed with an IRP/IRPA?

73. Enbridge Gas will apply to the OEB for approval to recover the costs associated with investment in any IRPA. Enbridge Gas presumes that such an application would, similar to applications for LTC facility alternatives, include an explanation of the system constraint/need, a summary of stakeholder engagement input, rationale for investment in the IRPA, the estimated individual and overall costs of investment, proposed cost allocation and recovery methodologies, proposed ownership and operationalization arrangements and a commitment to ongoing annual monitoring and reporting on the relative effectiveness of the IRPA to relieve the identified constraint. To provide some certainty of the effectiveness of IRPAs as early as possible, Enbridge Gas will build off its existing evaluation, measurement and verification ("EM&V") expertise to determine how the IRPA or IRPA portfolio is progressing in relation to targets. Enbridge Gas will identify and, where possible, resolve unanticipated operational challenges or flaws in the design or delivery of IRPAs that could impede its ability to reliably serve the needs of customers. If no such resolution is reasonably possible, then Enbridge Gas will evaluate the potential of new/incremental/replacement IRPAs and may consider ceasing investment in existing IRPAs that are not achieving the peak period demand reductions originally forecast.

Cost Recovery – Like Treatment for Like Results

74. Enbridge Gas proposes that the costs associated with an IRPA be included in its revenue requirement. The nature of the benefits associated with investments in IRPAs is like the facility expansion/reinforcement projects that they serve to defer, avoid or reduce in that they resolve forecast system constraints/needs. Accordingly, Enbridge Gas maintains that its proposal to treat the costs (either or both capital and O&M) associated with planning, implementing, administering, measuring and verifying the effectiveness of its investments in IRPAs in the same manner as the

costs for facility expansion/reinforcement projects (capitalized to rate base) that IRP will defer, avoid or reduce, is reasonable and appropriate. Similarly, and assuming that Enbridge Gas is approved to capitalize the costs of investments in IRPAs to its rate base, allocating the costs of IRPA investments in the same manner as the capital investments they serve to defer, avoid or reduce is also appropriate since the resulting benefits of system efficiency, reliability and resiliency will be shared amongst ratepayers. Allocating costs in this manner will also ensure that ratepayers avoid rate volatility that could otherwise be caused by significant investment in geo-targeted IRPAs.

75. Certain intervenors have previously made submissions acknowledging that it may be appropriate for Enbridge Gas to be incented to pursue the assessment of and investment in IRPAs.[41] Consistent with its response to those submissions, Enbridge Gas reiterates that the goal of such incentives is to broaden the interests of the Company from solely earning on infrastructure to also and equitably earning from its successes in deferring, avoiding or reducing future infrastructure requirements through investment in IRPAs. In Enbridge Gas's view, the simplest and most effective means of creating a level playing field from which to prioritize IRPAs and new facility infrastructure is by ensuring that Enbridge Gas is equally incented between the two types of investments. Should the Board wish to encourage Enbridge Gas to prioritize investments in IRPAs, then it could consider adding an incentive for such successful investments, over-and-above the regulated rate of return earned (e.g., an incentive based on the net benefits achieved, similar to the

[41] EB-2020-0091, Environmental Defence Submission on OEB Draft Issues List, June 4, 2020, p. 3; EB-2020-0091, Green Energy Coalition Submission on OEB Draft Issues List, June 4, 2020, p. 1; and EB-2020-0091, Pollution Probe Submission on OEB Draft Issues List, June 3, 2020, p. 5.

incentives proposed in other jurisdictions).[42] The topic of incentives might be appropriately examined in a study completed by the Company and brought forward as part of an upcoming annual Rates setting proceeding, at the time of Rate Rebasing, or as otherwise directed by the Board for determination in due course.

Recognition of Incremental Risk

76. As a regulated natural gas utility in Ontario, Enbridge Gas has an obligation to meet the firm contractual peak period (peak hour or design day) demands of its customers. Enbridge Gas's historic focus – and obligation - as the supplier of last resort has been to ensure that it has the assets required to safely and reliably meet its customers' immediate and long-term demands on an annual and design day basis (the coldest day of the year), and that will remain its top priority going forward in order to ensure that homes and businesses in Ontario have heat, hot water, cooking fuel and can perform the commercial/industrial activities (including electricity generation) that form the backbone of Ontario's economy.

77. Should Enbridge Gas's investments into IRPAs not result in the reduction of peak period demand anticipated, or in the event that supply-side alternatives experience a failure to deliver, there are few, if any, firm, cost-effective alternatives that Enbridge Gas can rely upon on short notice. For these reasons, Enbridge Gas: (i) has historically limited its reliance upon third-party services and discretionary overrun services to meet design day needs; (ii) has historically invested in safe and reliable facility expansion/reinforcement projects far enough in advance to ensure that it can meet its customers' demands (having recovered the costs of these investments

[42] Case 19-G-0066, Consolidated Edison Company of New York, Inc. *Proposal for use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure*, September 15, 2020, Section VIII. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-g-0066&submit=Search

through its regulated rates); and (iii) is focused on establishing an IRP framework that recognizes the risk of system failures/outages and increased costs to its customers inherent in investment in IRPAs as opposed to proven facility alternatives (including the cost to gather and manage more granular customer consumption data).

78. It takes approximately three to five (3 - 5) years to put a facility expansion/reinforcement project into service, including: project selection, preparation of an application to the OEB for LTC and subsequent approval, procurement of land rights, completion of relevant environmental studies and resulting impact mitigation efforts, to obtain all necessary permits, to order materials and to construct the facilities. Accordingly, IRPAs need to be implemented and measurably shown to be providing demand reductions capable of deferring, avoiding or reducing identified system constraints/needs in advance of this facility project timeline in order to ensure Enbridge Gas meets its obligation to serve the firm contracted demands of its customers. Such evidence of IRPA effectiveness is especially critical considering the nascence of IRP as an alternative to new infrastructure in Ontario, the limited jurisdictional precedent for natural gas IRP across North America and resulting uncertainty regarding the reliability of IRPAs to reduce natural gas peak period demands.

79. As discussed in more detail in Section 4.0 below, to accurately design and verify the effectiveness of investments in IRPAs it is necessary to have access to actual hourly customer consumption data, which is not currently available. By investing in Advanced Metering Infrastructure ("AMI"), Enbridge Gas can vastly improve the granularity of customer consumption data that it gathers, allowing for more precise IRPA design, more accurate forecasts of associated energy savings, higher quality monitoring and reporting on the effectiveness of IRPAs and allowing for more

informed decisions regarding whether to continue, adjust, increase or cease IRPA investments. Without access to hourly customer consumption data to establish more precise baseline load profiles, the design of proposed IRPAs and their respective forecasted and measured energy savings are expected to be less reliable, increasing the risk to ratepayers that OEB-approved IRPAs are not successful in resolving identified system constraints/needs. In the absence of hourly data, by the time that such conclusions regarding actual effectiveness are drawn, it may be too late to defer, avoid or reduce investment in facility expansion/reinforcement projects,[43] or may result in Enbridge Gas being unable to meet the firm contracted demands of its customers (i.e., causing system curtailment or outages). Said another way, without AMI – which is not being requested at this time - the Company will need to rely on system modelling around less certain or less well tested solutions to meet demand versus actuals. This will drive the need to overbuild the IRPA, as well as robust additional EM&V work, both of which drive up costs for IRPA(s).

80. Enbridge Gas has also proposed to report annually on the actual annual and cumulative effects of OEB-approved IRPAs relative to associated peak period demand reductions originally forecast (via an IRP report) and to seek OEB approval to adjust investments in such IRPAs as appropriate (e.g., to shift funding to an alternate IRPA or to increase/decrease/cease investment in IRPAs accordingly). Enbridge Gas expects that any and all of the prudently incurred: (i) original costs to invest in OEB-approved IRPAs; (ii) costs associated with OEB-approved adjustments to IRPA investments; and (iii) costs of any subsequent OEB-approved LTC project (in the instance that an IRPA is determined to have been insufficiently effective), would be borne entirely by ratepayers subject to the Board's

[43] In this scenario, ratepayers will have funded unsuccessful IRPA investments and facility expansion/reinforcement project investments.

determination that in the course of incurring such costs Enbridge Gas acted prudently and responsibly in serving the firm needs of its ratepayers.

81. Considering the level of transparency and oversight proposed by Enbridge Gas for any OEB-approved investment in IRPAs, it is entirely reasonable that ratepayers, not Enbridge Gas, bear the costs associated with the success or failure of such investments given that: (i) through its prior orders/directives/findings and the establishment of an IRP framework for Enbridge Gas, the Board has encouraged Enbridge Gas to pursue IRP as an alternative to proven facility expansion/reinforcement projects; (ii) Enbridge Gas remains obligated to serve the firm contractual peak period demands of its customers; (iii) such treatment of risk is consistent with investments in facility expansion/reinforcement projects that Enbridge Gas is seeking to defer, avoid or reduce through investment in IRPAs; (iv) the Board will have the opportunity to thoroughly review any future request for cost recovery associated with investment in IRPAs together with intervenors prior to Enbridge Gas initiating such expenditure; and (v) Enbridge Gas intends to report regularly to the OEB and stakeholders on the relative effectiveness of IRPAs to affect the peak period demand reductions forecasted, on the ongoing viability of supply-side alternatives, and to seek approval of the Board prior to adjusting such previously approved investments or to pursue investment in facility expansion/reinforcement project alternatives.

Monitoring and Reporting

82. In PO No. 2, the Board set out to establish the appropriate approach for monitoring and reporting on the progress of IRP Plans, including consideration of metrics and an IRP scorecard that Enbridge Gas would need to develop as part of its IRP framework.

83. Enbridge Gas acknowledges that ongoing monitoring and reporting of its investments in IRPAs is necessary to provide some certainty of the effectiveness of IRPAs as early as possible. This ongoing monitoring and reporting will be regularly fed into the IRP process to ensure systems are able to meet their capacity requirements, to address any operational challenges, to address flaws in the design or delivery of IRPAs, and/or to make additional investments in IRPAs or new infrastructure.

84. To provide transparency of the effectiveness of IRPAs implemented, Enbridge Gas proposes that an annual IRP Report should be included with its annual Deferral and Variance Account Disposition and Earnings Sharing Mechanism applications, its annual Rates applications, or as otherwise directed by the Board beginning after the first IRPA/IRP is approved. The IRP Report will provide annual and cumulative summaries of actual peak period demand reductions/energy savings generated by each IRPA compared to the initial forecasted reduction/energy savings and the actual amount of expenditure on each IRPA to-date. Table 3.2 below provides a sample template of the initial IRP Report.

Table 3.2:
Proposed Monitoring and Reporting Table

Program	**Annual Natural Gas Demand Reduction (GJ/m^3)**			**Cumulative Natural Gas Demand Reduction (GJ/m^3)**	**Cost ($ million)**			**Cumulative Cost ($ million)**
	Forecast	Actual	Variance		Forecast	Actual	Variance	
Sample	5,000	5,000	0	5,000	1.1	1.1	0	

85. This template should be used as a starting point for the OEB's Monitoring and Reporting requirements. Enbridge Gas recognizes that there may be iterations to the reporting template as experience is gained in IRPA implementation.

Stakeholdering

86. Enbridge Gas acknowledges the importance of stakeholder engagement in effective planning processes. Currently, various departments across Enbridge Gas gather information from external sources and stakeholders to inform regional growth projections, including: building permit information received from municipalities, new construction growth informed by housing starts forecasts, unemployment rates, natural gas commodity prices, vacancy rates, GDP, customer interests etc. Enbridge Gas's DSM team conducts stakeholder engagement directly with end use customers, customer associations and through research tactics to inform its multi-year DSM planning efforts. The DSM team also engages with municipalities in their municipal energy planning efforts, providing aggregated consumption data for the various municipal regions, and allowing these municipalities to benchmark natural gas consumption to inform their Community Energy Planning ("CEP") process. Further, formal customer engagement surveys are used to inform asset management planning and during certain rates applications (e.g., as part of Rate Rebasing).

87. Despite these extensive engagement activities, Enbridge Gas accepts that there may be room to enhance its stakeholder engagement in order to glean IRP-specific insights. These additional insights could be geographically-specific and include information on customer types (e.g., residential, commercial, industrial), socio-economic customer attributes, housing stock, saturation of current DSM programming, and an understanding of the status of electricity CDM programs as well as transmission and distribution capacity.

88. Accordingly, the objectives of the IRP Stakeholder Engagement process will be to: (i) ensure planned resources will meet Enbridge Gas's obligation to safely and reliably deliver firm contracted demands; (ii) gather ample geographically-specific

information such that IRPAs can be adequately reviewed and monitored; (iii) help inform the development of new or enhanced energy efficiency programming; and (iv) broadly inform Enbridge Gas's long-term strategic planning.

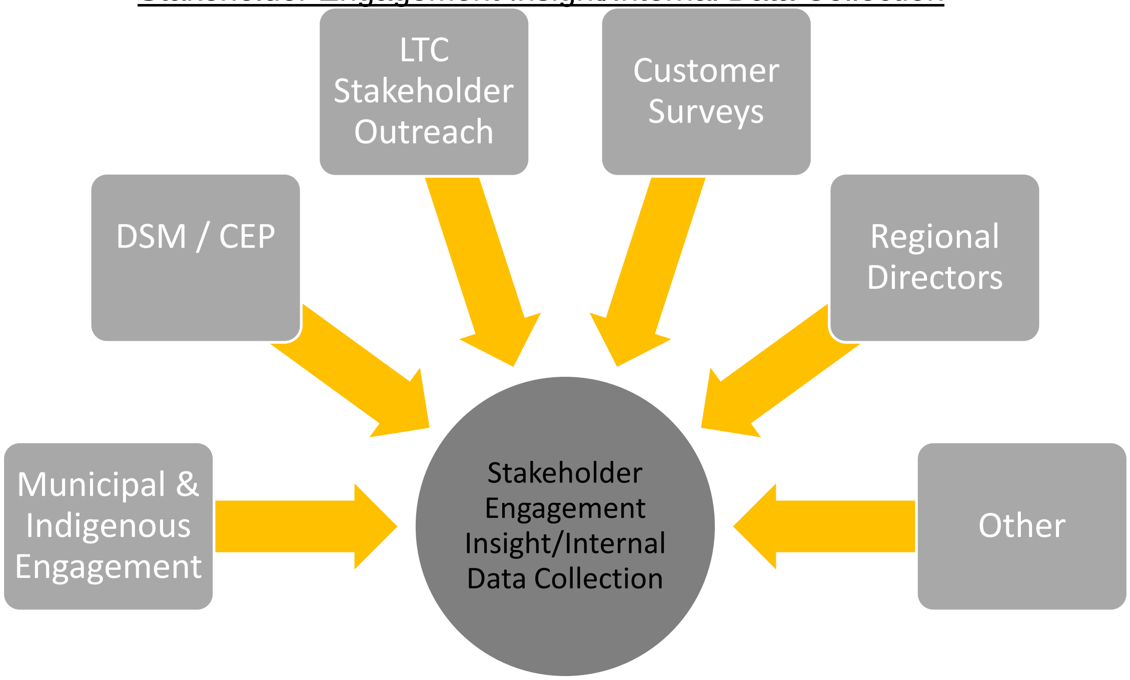
89. Stakeholder engagement for IRP will include three engagement components:

- Component 1: Gather and analyze data and insight from ongoing stakeholder engagement initiatives. These ongoing stakeholder engagement initiatives may be modified to elicit any new information required to enable IRPA analysis;
- Component 2: Discussion on IRP during Stakeholder Days;
- Component 3: IRPA project geographically-specific stakeholder engagement completed prior to filing a proposed IRPA with the OEB.

Component 1: Gathering of Stakeholder Engagement Data and Insight

90. As outlined in Figure 3.1, Enbridge Gas will seek insights from stakeholders and various market participants by working within existing stakeholder engagement channels to mitigate incremental expenses and leverage existing relationships. These existing channels to stakeholders include: municipal, First Nations and Indigenous engagement, DSM, market surveys, LTC stakeholder outreach, utility regional directors, outreach to customer associations and formal/informal dialogue with customers of all types (e.g., through sales representatives). Gathering of stakeholder data and insight will ideally occur on an ongoing basis.

Figure 3.1:
Stakeholder Engagement Insight/Internal Data Collection



Component 2: Enbridge Gas Stakeholder Days:

91. IRP will be included for discussion during regulatory stakeholder days (conducted as required by the OEB or as deemed appropriate by Enbridge Gas), allowing interested parties to ask questions and provide input on IRP-related matters and providing a regular opportunity to gain insights into Enbridge Gas's IRP planning and implementation activities.

Component 3: IRPA Project Geographically-Specific Stakeholder Engagement:

92. The final component of stakeholder engagement related to the IRP planning process will involve consultation dealing with specific IRPAs (identified for a specific need in a specific geographic region). The purpose of this component of stakeholder engagement is to share information about an identified IRPA with stakeholders from the specific geographic area relevant to the IRPA. Feedback from this consultation

work will inform and help shape any IRPA implementation proposal that might ultimately be filed with the OEB for approval.

93. Enbridge Gas proposes that this geographically-targeted stakeholder engagement should, at a minimum, mimic stakeholder outreach implemented as part of new infrastructure expansion/reinforcement projects and the resulting feedback should form part of Enbridge Gas's IRPA application in the same manner that such activities are included in LTC applications. For clarity, this consultation would certainly include municipalities in the area of impact for the IRPA, local Indigenous groups, local customers, builders and developers and other relevant stakeholders in that geographic area. Enbridge Gas notes that each geographic area being consulted regarding a particular IRPA(s) will have different attributes and may have unique stakeholders not previously referenced.

4.0 IRP Enabling Infrastructure

94. Enbridge Gas's current lack of actual measured peak hourly data makes it difficult to understand the actual potential of IRPAs with precision and will make it difficult to measure, verify and report on actual load profiles in the area as a baseline and subsequently, the effectiveness of IRPAs in reducing peak period demand. This knowledge gap increases the risk and, potentially, the cost to ratepayers of investments in IRP (e.g., if Enbridge Gas determines at some future point in time, through limited existing measurement data, that an approved IRPA has not performed as anticipated and that there is insufficient time to adjust the IRPA or to seek incremental IRPA investment). In its IRP Study, ICF recognized this gap and the limitations/risks inherent in proceeding with investment in IRPAs without this data. ICF found that "…until the gas industry invests in advanced metering

technology, it will be challenging for the gas utilities to measure the impacts of DSM programs on baseline peak hour demand."[44]

95. At such time that Enbridge Gas begins to rely upon IRPAs to offset peak hourly demands and to defer, avoid or reduce investment into infrastructure expansion/reinforcement projects, insight on actual hourly customer consumption data will be critical to ensuring that all categories of IRPAs have delivered peak hourly energy savings as forecasted. Access to this hourly data will enable Enbridge Gas to confidently monitor and report on the effectiveness of IRPAs to the OEB, will inform future investment in IRPAs by allowing Enbridge Gas to focus investments on the IRPAs with the highest potential to reduce peak period demand and will enable Enbridge Gas to shift funding from less effective IRPAs to new or more effective ones, or to cease funding IRPAs, as appropriate.

96. Absent more granular consumption data that would be available from AMI implementation, more conservative derating factors will need to be applied towards consideration of a given alternative and, incremental evaluation policy and/or protocols may need to be designed and implemented at additional cost. In addition, and similar to the approach in other jurisdictions, Enbridge Gas anticipates that continued monitoring of future IRPA activities, projects and evaluation studies will also be necessary to ground and refine future analysis and projections of demand savings that could be attributed to potential IRPAs being investigated. Consequently, this work may need to be more robust absent access to more granular consumption data.

[44] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. ES-9.

Advanced Metering Infrastructure

97. AMI is an integrated system of meters, end points, communications networks, and data management systems that enable two-way communication between utilities and customer meters. The deployment of an AMI system, including ultrasonic meters, allows for the collection of frequent interval data that Enbridge Gas requires to effectively target IRPAs and to monitor and verify their effectiveness to ensure that the IRPAs are performing as expected and to ensure peak period demand reductions are materializing.[45]

98. Recently in its paper, The Role of Energy Efficiency in a Distributed Energy Future ACEEE stated that "Advanced metering is important because it provides system planners and evaluators with more granular data and increases the speed of feedback, which helps with planning and delivering DERs."[46] As well, in a paper published by Columbia Law School it was indicated that,[47]

> AMI deployment may offer a way of managing the anticipated growth in natural gas consumption, without the need for new pipeline construction. Of course, whether new construction can be avoided by deploying AMI will depend on local conditions, including current and anticipated future levels of pipeline throughput. As a general rule, AMI deployment is likely to prove most useful in areas where pipelines are at or approaching maximum throughput, and only modest demand growth is expected in the near future. In such cases, even the relatively small reductions in natural gas use associated with AMI deployment (i.e., one to four percent) may enable new pipeline construction to be avoided, at least in the short-term. This would provide additional time for LDCs to pursue other measures that further reduce natural gas use and thereby avoid the need for new pipelines in the long-term.

[45] EB-2020-0091, FINAL REPORT Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment, July 22, 2020, p. ES36.

[46] American Council for an Energy-Efficient Economy, The Role of Energy Efficiency in a Distributed Energy Future, Brendon Baatz, Grace Relf, and Seth Nowak, February 2018, Report U1802. Pages 48 – 49. https://www.aceee.org/research-report/u1802

[47] Columbia Law School DEPLOYING ADVANCED METERING INFRASTRUCTURE ON THE NATURAL GAS SYSTEM: Regulatory Challenges and Opportunities, By Romany Webb, July 2018, Section 3.2 AMI as a Non-Pipes Alternative, p 11. http://columbiaclimatelaw.com/files/2018/07/Webb-2018-07-AMI-and-Natural-Gas.pdf

99. Currently in Canada, the ultrasonic meters that would support AMI are being reviewed by Measurement Canada. Once approved, these meters would also need to undergo testing by Enbridge Gas's measurement experts before they can be proposed for deployment within Enbridge Gas's franchise area. Enbridge Gas anticipates that ultrasonic meters will receive Measurement Canada approval at some point in mid to late 2021, that Enbridge Gas will continue to assess the feasibility of an AMI implementation and that Enbridge Gas may be in a position to advance AMI-specific applications and a viable roll-out strategy to the Board as soon as 2022.

100. Recently more natural gas utilities across North America are considering the implementation of AMI technology. In Canada, FortisBC is expected to file with the British Columbia Utilities Commission to upgrade their natural gas meters as part of the Advanced Gas Meters project.[48] In addition, ConEd, SoCal Gas and PG&E have all initiated or completed the roll out of natural gas AMI technology and networks.

101. Enbridge Gas is not proposing to deploy AMI at this time. Rather, recognizing the significance of such a deployment and its implications to the successful design, implementation and verification of investments in IRPAs as well as its use by other natural gas utilities currently investing in IRP across North America, Enbridge Gas has included this section of its evidence for informational purposes.

102. As Ontario's energy landscape evolves to become more integrated and sophisticated with technological advancements unlocking access to more granular and real-time customer consumption data for both electricity and natural gas, there

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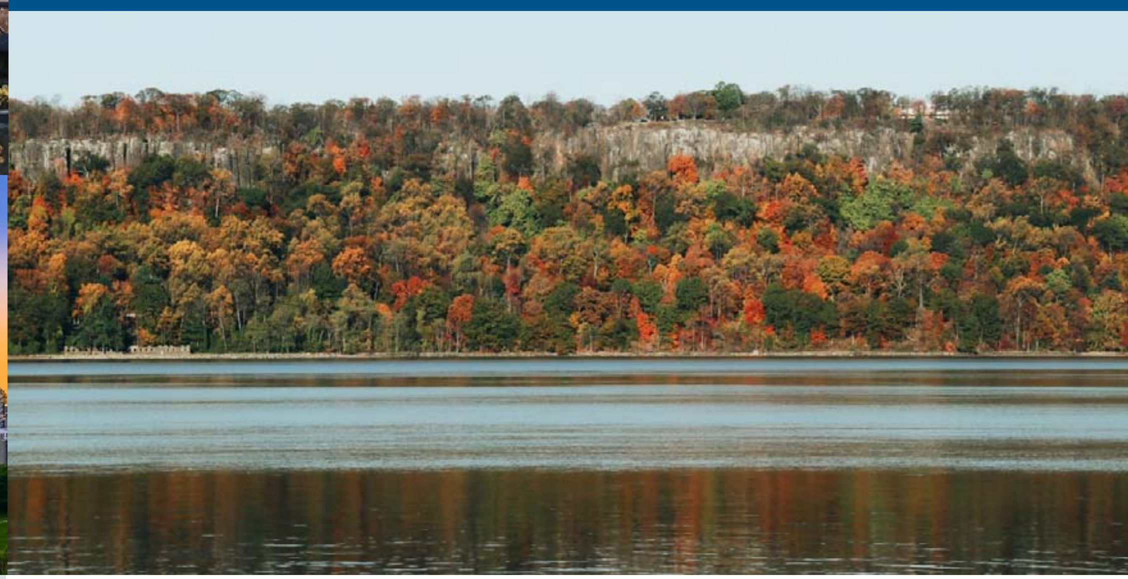
[48] https://www.fortisbc.com/about-us/projects-planning/natural-gas-projects-planning/advanced-gas-meters

will be an increased need to measure peak period demand activity in order to fully understand and optimize energy system activity. Investment in natural gas AMI deployment in parallel with future investments in IRPAs, will enable: (i) Enbridge Gas to advance IRP as efficiently and effectively as possible; (ii) Enbridge Gas to gain a deeper understanding of the aggregated implications of investments in natural gas IRPAs on its respective systems/assets in the future; and (iii) the OEB to make informed decisions in the best interest of rate payers with confidence that those decisions are being made based on actual peak period consumption data, critical at a time when the effectiveness of IRPAs to avoid investment in new natural gas infrastructure expansion/reinforcement projects in Ontario remains uncertain and public policy mandates greater energy system integration and efficiency.

5.0 Conclusion

103. In conclusion, the 2019 IRP Policy Proposal filed in November 2019 and this supplemental evidence describe Enbridge Gas's process for identifying, developing, implementing, and recovering costs for IRPA(s) that would defer, avoid or reduce new facility projects. The Company respectfully requests OEB approval of the specific proposed process (i.e., the Company will screen system needs, then undertake a two-stage review process that is completed on an economic basis with consideration of the Guiding Principles and file IRPA plans with the OEB prior to implementing an IRPA) and the Company's proposed approach to treat IRPAs in a similar manner as new natural gas facility infrastructure (i.e., rate base treatment for IRPAs).

IRP Jurisdictional Review Report



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Acronyms

AMI	advanced metering infrastructure
BCA	benefit-cost analysis
BQDM	Brooklyn Queens Demand Side Management
Btu	British thermal unit
BBtu	billion British thermal unit
C&I	commercial and industrial
CHP	combined heat and power
CNG	compressed natural gas
DER	distributed energy resources
DR	demand response
DSM	demand-side management
EE	energy efficiency
FERC	Federal Energy Regulatory Commission
GJ	gigajoule
IRP	integrated resource planning
JUNY	Joint Utilities of New York
LNG	liquefied natural gas
MBtu	thousand British thermal unit
MMBtu	million British thermal unit
MW	megawatt
NESE	Northeast Supply Enhancement
NPS	non-pipe solutions (also referred to as non-pipe alternatives (NPA))
NSPM	National Standard Practice Manual
NWS	non-wire solutions (also referred to as non-wire alternatives (NWA))
NYISO	NY Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
PSC	New York Public Service Commission
RGGI	Regional Greenhouse Gas Initiative
REV	Reforming the Energy Vision
RIM	rate impact measure
RNG	renewable natural gas
SCT	societal cost test
TRC	total resource cost test
TRC-plus	total resource cost test plus
UCT	utility cost test

NOTE: Exchange rate used in this report: 1 USD = $1.35 CAD

Executive Summary

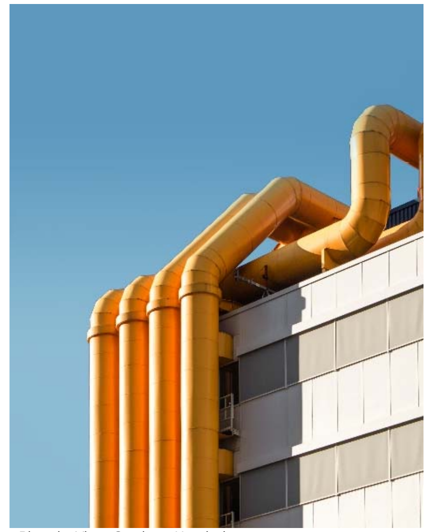
Photo by Victor Garcia on Unsplash

In 2018, ICF completed an integrated resource planning study (hereinafter "2018 IRP Study") for Enbridge Gas Inc. (hereinafter "Enbridge") focused on assessing the viability of employing targeted energy efficiency as an alternative to natural gas distribution system reinforcement infrastructure projects.[1] The 2018 IRP Study included a jurisdictional review and consultations to determine the progress that had been made on this topic by other North American utilities.

At the time, ICF found that, while Demand Side Management (DSM) and Demand Response (DR) programs by electric utilities to reduce the need for new generating capacity and transmission capacity had been underway for many years, there was only limited experience deferring investments in gas distribution and transmission system infrastructure using these approaches.

While ICF found that a few natural gas utilities had started looking into the potential impact of DSM programs on system infrastructure requirements before 2018, these efforts were in the early stages. Furthermore, at that time ICF was unable to identify a natural gas utility that had implemented geo-targeted[2] DSM programs to actively avoid investing in distribution system infrastructure in specific areas.

Enbridge retained ICF to update the jurisdictional review that was performed as part of the 2018 IRP Study to assess recent developments in the use of energy efficiency as a gas infrastructure alternative. This report provides the results of this review. In this report, ICF uses a broad definition of Non-Pipe Solutions (NPS), including both demand-side and supply-side alternatives to investments in gas infrastructure. This includes fuel switching to electricity,[3] employing compressed natural gas (CNG) or liquefied natural gas (LNG), and implementing geo-targeted DSM. ICF's definition of geo-targeted DSM includes geo-targeted energy efficiency (EE) as well as gas demand response (DR) and electrification (e.g. from natural gas furnaces to electric heat pumps).

I. Jurisdictional Review

ICF updated the jurisdictional review and consultations it previously performed in 2017 and published in 2018.[4] The jurisdictional update was intended to highlight progress that has been made on NPS by other North American utilities since 2017. ICF and Enbridge were aware of the NPS efforts being made by gas utilities in New York State, which are often seen as being at the

[1] ICF, *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report*, 2018. Completed on behalf of Enbridge Gas Distribution Inc. and Union Gas Limited.
[2] "Geo-targeted" is an attribute used in this report to describe a demand-side program or technology solution that focuses on one or many branches of a gas distribution system. Its opposite is "broad-based."
[3] Most sources consulted do not consider fuel switching to delivered fuels (e.g. heating oil or propane) or interruptible rates (which requires clients to have an alternate fuel to switch to), to be legitimate NPS.
[4] ICF, *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report*. Completed on behalf of Enbridge Gas Distribution and Union Gas Limited.

forefront of NPS efforts. For this reason, we placed a special focus on New York State. ICF found results that varied considerably between gas utilities in New York State and other States/Provinces across North America.

Utilities Outside New York State

ICF reviewed relevant progress in Vermont, New Hampshire, Massachusetts, Oregon, and British Columbia. In these States, limited notable progress has been made since the 2018 IRP study, in terms of the number of demand-side NPS targeted projects being considered and implemented, with the exception of one geo-targeted energy efficiency (EE) pilot program in Oregon led by NW Natural and Energy Trust of Oregon.

Standard DSM (i.e. broad-based DSM[5]) is considered in many states and provinces as a useful tool to defer infrastructure investments. However, DSM program designers typically give limited consideration to the timing and location of the gas savings in their program designs relative to the need for infrastructure projects.

Throughout North America, the 2020 review found that utilities are still encountering many of the same barriers to NPS that ICF identified in the 2018 IRP Study:

- **Reliability of NPS forecast:** The gas industry has a particularly low risk tolerance for outages because of the amount of manpower, time and cost required to restart their systems. There are also health and safety risks associated with customers not having access to space heating during the extended period of an outage during the middle of winter. It remains to be proven that geo-targeted DSM can result in peak period reductions that are as reliable as traditional pipes.
- **Lack of metered data:** The lack of availability of granular peak hourly customer data remains a challenge, both in terms of estimating and validating peak demand impacts. Most customers have monthly-read meters, so gas utilities can only identify peak demand at their city gate stations. Technology options exist for gas advanced metering infrastructure (AMI), which would provide more granular data (i.e. typically hourly intervals), but current deployment levels are low. In the absence of gas AMI meter data, ICF noted that some utilities are using alternate approaches to evaluate peak demand impacts as part of current or upcoming geo-targeted EE or DR pilot projects.
- **Changing lead times for projects:** Both large infrastructure projects and NPS have long implementation timelines. There is a risk that deployment of an NPS may not be able to offset the demand on time to avoid a shortage, at which point it will be too late to build the regular pipe solution on time. The 2018 IRP Study suggested a utility would require a 5-year timeline to properly implement DSM as an alternative to infrastructure investments. In other words, if a shortage is forecasted in less than five years, the pipe solution may be preferable to avoid outages. Anecdotal evidence collected as part of this study supports maintaining this lead time rule.
- **Changes in the infrastructure approval process for geo-targeted DSM:** Traditional gas infrastructure is typically planned three to five years ahead of when it is required, while DSM programs get approved independently and have shorter lead times before costs can be accrued. It is challenging to rely on the availability of multiple years-worth of cumulative DSM impacts if all the associated expenses for such programming have not been approved on a long-term basis.

[5] In this report we will use the attribute “broad-based” to describe the opposite of geo-targeted DSM, standard DSM. Standard DSM focuses on the entire service territory of a gas utility, or large areas of the service territory of a gas utility served by a transmission pipeline.

- **Appropriateness of cost-effectiveness testing:** As part of the 2018 IRP Study, ICF was unable to identify guidance on cost-effectiveness testing in the context of NPS as compared to that of broad-based DSM. It was our general recommendation that cost-effectiveness testing for NPS should accumulate the value of deferral or avoidance of local infrastructure investments and upstream costs such as avoided commodity costs, avoided carbon costs, and deferral or avoidance of transmission investments. The main adopted guidance that ICF identified is ConEdison's Benefit-Cost Analysis Handbook for NPS, which was first published in 2018 and was updated as of September 14, 2020[6].
- **Principle of universality, cross-subsidization:** Broad-based DSM program incentives are accessible to all customers by design and in the spirit of fairness. They are designed to minimize cross-subsidy between rate classes, and to keep cross-subsidy between participants and non-participants under a maximum acceptable level. The implementation of geo-targeted DSM may go against these principles. The utilities ICF spoke with outside New York State remained concerned that the issue could be raised during regulatory proceedings.
- **Overlap with broad-based DSM:** The question remains whether geo-targeted DSM should be funded within the budgetary envelope of broad-based DSM or over and above broad-based DSM. Either way, a crucial question is how much additional funding (and corresponding customer incentive top-off) is required to generate incremental impacts. Outside of New York State, this does not seem to be a significant concern. For instance, NW Natural has addressed this issue by investing in additional marketing and education in the area being geo-targeted for its ongoing pilot rather than increasing spending on customer incentives. In New York State, ICF has found that utilities are testing incentive kickers that are significantly higher than the broad-based DSM incentive to ensure that they are creating measurable impacts.
- **Utility remuneration and incentives to pursue NPS:** NPS has the potential to provide lower cost and more modular alternatives to large infrastructure capital expenditures that would be included in rate base and amortized over a long asset book life. Large infrastructure capital expenditures generate attractive net income for utility companies, sometimes for decades. However, NPS projects may not add to rate base or create an incremental return for the utility without special regulatory treatment. As such, they can be less attractive to utilities relative to more traditional investment options. This was already an issue with broad-based DSM investments, but becomes more acute with pursuing geo-targeted DSM and other NPS because the scope and expectation for deferring infrastructure investments is often much larger. The challenge is not necessarily novel. It has been addressed for regular, broad-based DSM through either rate basing the entire DSM expenditures, like in Quebec, British Columbia, and Massachusetts, and/or creating a performance incentive that is added to a lost revenue adjustment mechanism and cost recovery, like in Ontario. Performance incentives have the potential to be used to offset foregone earnings associated with the reduction in long term infrastructure investments.
- **Additional research:** Most gas utilities agreed that significant additional research and pilot testing is required before NPS – particularly geo-targeted DSM – can be relied upon to the same extent as traditional infrastructure investments.

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[6] ICF identified two cost-benefit analysis publications that call out NPS: ConEdison's Benefit-Cost Analysis Handbook, and the August 2020 National Standard Practice Manual for DER (NSPM for DER). NPS are called out five times in the 2020 NSPM for DER, many of the principles of benefit-cost analysis applicable to NWS do also transfer over to NPS, but the 2020 NSPM for DER is not as explicit and clear on NPS than ConEdison's Benefit-Cost Analysis Handbook for NPS.

New York State Utilities

In New York State, the NPS story is more advanced. Since the 2018 ICF study was completed, the natural gas distribution companies and regulators within New York State have made significant progress in the development of NPS as an alternative to traditional natural gas infrastructure investments.

The New York State experience with NPS provides important insights for Ontario. However, these insights need to be evaluated carefully to ensure that they are applicable to Ontario given the significant differences between the New York and Ontario natural gas markets.

- These differences include fundamentally higher energy costs in New York State, which tend to improve the economics of NPS options in the State. Demand in New York State also tends to be peakier than in Ontario, which increases the costs of conventional pipeline capacity relative to NPS options. Both factors improve the economics of NPS options in New York relative to Ontario.
- New York State utilities are blending CNG directly into their distribution systems and are planning to employ distributed LNG facilities to deliver peak period natural gas directly to constrained sections of their distribution system as part of their NPS plans. They have also implemented a limited number of geo-targeted EE, gas DR and electrification pilot projects and are considering additional pilot projects to address broader capacity constraints.
- Although the number of NPS projects in the State are limited (with the exception of the implementation of distributed supply sources including LNG and CNG), the projects that have been implemented have generated useful results and led to ongoing discussions that are helping to lay the groundwork for a more widespread use of such solutions. However, to date, the demand side pilot projects have been too small in scale to lead to deferring or avoiding infrastructure.

The New York State Public Service Commission has approved in principle rate treatment for NPS expenditures.

> *"Under the new NPA mechanism, the difference in costs between an NPA implemented during the term of the Proposal and costs in rates associated with the displaced project, including the overall pre-tax rate return on such costs, will be recovered as a regulatory asset through Con Edison's Monthly Rate Adjustment clause. Unamortized NPA costs, including the return, will be incorporated into the Company's base rates when gas base delivery rates are reset. These provisions are included to provide an incentive to the Company to pursue cost-effective alternatives to traditional electric CASES 19-E-0065 and 19-G-0066 and gas infrastructure investment in furtherance of Commission policy."*[7]

II. Drivers of NPS in New York State

In some ways, the natural gas market in Ontario is similar to the market in New York State. However, there are also significant differences between the jurisdictions. As a result, the experience with NPS in New York State provides a useful reference for Ontario. At the same time, a detailed understanding of the differences and similarities between the markets and the potential drivers of NPS in each market is necessary to understand the relevance of the New York State NPS experience to Ontario. The main drivers for NPS in New York State include a combination of the following factors:

[7] NYPSC Order Approving the Joint Proposal January 16, 2020.

- The high natural gas and power distribution infrastructure costs, particularly in Downstate New York (New York City and Long Island), which makes the economics of both non-wires solutions (NWS) and NPS better than the economics of NWS and NPS in other jurisdictions.
- A high percentage of residential and commercial demand, which has reduced the load factor of natural gas demand in New York State relative to jurisdictions with higher percentage of industrial demand, including Ontario. The peaky nature of natural gas demand in the state improves the economics of many of the forms of NPS.
- A unique and challenging situation related to continuing demand growth as New Yorkers switch from using heating oil to cleaner burning natural gas and the difficulties associated with building new pipeline capacity to serve natural gas demand growth, particularly in Downstate New York.
- The presence of joint natural gas and electric utilities that may have a higher degree of comfort with certain NPS options, such as gas-to-electricity conversion.
- Clear, consistent top-down policy direction from the New York State government related to transitioning to a decarbonized economy and prioritizing DSM and other demand-side options as alternatives to investments in new pipeline capacity.
- An extensive precedence with distributed energy resources (DERs) used to alleviate local electricity distribution system constraints (i.e. non-wire solutions (NWS)).

The remainder of this section provides a comparative analysis of Ontario and New York State with respect to the drivers of NPS.

Energy Sector

The New York State and Ontario energy sectors have a number of similarities, including overall energy sales volumes, access to multiple natural gas supply basins, interstate pipeline systems, and major natural gas storage facilities. There are also significantly different in certain areas that determine the usefulness and economics of NPS, including cost of infrastructure, corporate and regulatory structure, and planning processes. These similarities and differences are summarized below:

Photo by Joshua Newton on Unsplash

- Building energy consumption is similar in terms of magnitude (i.e. New York State buildings consumed 1,920 PJ of energy in 2018, while Ontario buildings consumed 1,916 PJ).
- There are differences in how natural gas is used in New York State compared with Ontario. In New York State the residential sector uses 55% of the natural gas consumed in the State, followed by the commercial sector (34%), and the industrial sector (10%). This is very different from Ontario, where the proportion of natural gas consumption is more equally distributed between the residential (32%), commercial (32%), and industrial sectors (36%). The higher share of residential demand and the lower proportion of industrial gas demand in New York State leads to a “peakier” hourly demand profile, increasing the relevance of peaking solutions. The larger percentage of residential and commercial customers also makes New York State’s load growth smoother and more predictable. Conversely, shifts in the demand of a relatively small number of industrial customers in Ontario can dwarf the impact of both broad-based and geo-targeted DSM.

- The retail prices of gas and electricity are also significantly higher in New York State compared to Ontario. For instance, residential electricity and gas retail prices in New York City are twice as high as those in Toronto. This difference is driven by the lower cost of natural gas and electricity distribution infrastructure in Toronto. Upgrading and building new infrastructure in and around New York City is not only costly, but also very disruptive to local economic activity. This led gas utilities in Downstate New York to increase their reliance on peaking solutions, such as delivered CNG injection in densely populated areas. These solutions are less cost-effective in many other jurisdictions in North America, including Ontario.
- New York State's building stock is older and has a tradition of heating with heating oil. Much of the building stock has been converted to natural gas over the past several years. These conversions have been encouraged by local by-laws banning heating oil and incentive programs focused on converting customers to natural gas. However, there are still a significant number of buildings that remain to be converted. As a result, peak natural gas load in New York State has increased more quickly than in Ontario. Continued growth in the State is expected to keep putting upward pressure on natural gas peak demand, potentially increasing the value of NPS capable of deferring new infrastructure investments.

Utility Corporate Structure

Unlike Ontario, New York State has (mostly) joint gas and electric utilities.[8] This can help facilitate more cohesive actions and lead to cross-pollination between the electricity and natural gas distribution businesses. Their business model is more comfortable with gas to electricity conversions because business lost by the gas arm of a utility is simply captured by the electric arm of the utility. It also makes electrification easier to implement since one company is on both sides of the energy conversion.

Utility Regulatory Structure

The utility regulatory structure in New York State has been more conducive to the development of NPS than the structure in Ontario:

- In New York State, both electricity and natural gas distribution companies are regulated by the same oversight organization with a generally consistent regulatory structure. This is further facilitated by the corporate structure of the utilities, where most tend to be joint gas and electric companies, which leads to more consistent DSM frameworks. New York State just went through the latest DSM filing – the Accelerated Energy Efficiency proceeding – during which the Public Service Commission (PSC) jointly set targets and budgets for both broad-based gas and electric DSM for all utilities. In Ontario, the electric and gas utilities and DSM frameworks have different oversight models, different target-setting and reporting calendars, different benefit-cost analysis frameworks, and different third-party evaluation approaches. For example, Ontario's gas DSM framework is under the purview of the Ontario Energy Board (OEB) and the electricity conservation programs are being implemented by the provincial system operator, the Independent Electricity System Operator of Ontario (IESO), under the purview of the Ontario's Ministry of Energy, Northern Development, and Mines.
- Ontario and New York State are similar in their use of performance incentives for utilities as part of rate regulation. In New York State, performance incentive models for utilities are

[8] Key exceptions include National Grid of New York and Long Island, which is gas only, and Long-Island Power Authority, an electricity-only utility. National Grid of New York distributes gas to a significant part of the ConEdison electric service territory. National Grid of Long Island distributes gas to the service territory of Long-Island Power Authority.

referred to as “earnings adjustment mechanisms”. Essentially, a performance incentive is an adder to the revenue requirements, allowing utilities to collect more revenues from rates than what is needed to meet cost of service, thereby adding to their profit in addition to regulated rate of return. Both jurisdictions use incentive models to encourage utilities to meet and sometimes exceed energy savings targets for broad-based gas DSM. Both performance incentive models are generally pegged in full or in part to achievement of broad-based annual savings (either in terms of annual incremental savings or lifetime net cumulative savings). Ontario’s approach relies on a scorecard that includes but is not limited to energy savings. Most of New York State’s DSM earnings adjustment mechanism is tied exclusively to realized energy savings.[9]

- New York State pioneered the use of a novel incentive model for DER used to avoid or defer electricity distribution system investment – or NWS. Electric utilities in Downstate New York tested their first NWS projects more than a decade ago and New York State is moving towards a mature NWS market where NWS are compared fairly with traditional wired solutions. The vision is to have NWS and traditional wired solutions deployed where and when preferable to ensure services are delivered to customers at the lowest cost to society. Incentives for NWS include rate base of alternatives plus a portion of net benefits – as opposed to savings – according to a pre-defined Benefit-Cost Analysis (BCA) framework designed specifically for NWS by the New York electric utilities, under the supervision of the PSC. The incentives compensate for the foregone earnings from not deploying traditional wire solutions and turn NWS into a profit-making activity for the investor-owned utilities of the State.


Photo by American Public Power Association on Unsplash

  A performance-based incentive like NWS has not yet been agreed upon for NPS in New York State. However, progress is anticipated on this point given ConEdison’s recent proposal requesting performance incentives for NPS similar to those that are available for NWS. The vision shared by the PSC is to move towards a routine and fair assessment of NPS against traditional pipe solutions as part of an updated approach to gas long-term capacity planning.

- Performance-based incentives for supply side options, including distributed CNG and LNG, have proven more challenging. The PSC and other stakeholders have viewed the deployment of CNG and LNG peaking solutions simply as being related to the utilities’ responsibilities to deliver gas to their firm-rate customers through the winter. In addition, the role of renewable natural gas (RNG) is relatively limited for practical reasons. For example,

[9] In ConEdison’s proposed EAM included in the 2019 electric and gas rate case “Joint Proposal” (filed on October 16, 2019 under Case 19-E-0065z), most of DSM related EAM are tied to achieved energy and capacity savings in MWh, MW and MMBtu except for DER utilization (solar PV, storage, and wind) measured in adoption rate in MWh and beneficial electrification tied to GHG reductions provided by EV and heat pumps adoption, which can also be considered DSM. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8DFF975D-C514-41C8-8E31-82C33318D898}

the capacity of RNG facilities located in core city areas is limited by land occupation, population density, and the availability of locally-sourced feedstock.

Pipeline Infrastructure and Planning Processes

In New York State, the siting and the environmental assessment of new interstate pipeline projects are subject to a high degree of public scrutiny. Combined with the proactive nature of New York State's climate change policy, this has created a situation where it is extremely challenging to develop major new pipeline assets to meet demand growth.

This is a critical factor driving the consideration of NPS in the State. For example, the Transcontinental Pipeline's Northeast Supply Enhancement (NESE) was proposed to add supply capacity in Downstate New York – largely for ConEdison and National Grid of New York and Long Island. After first applying for state permits in June 2017, NESE was repeatedly denied its Section 401 Water Quality Certification by the New York State Department of Environmental Conservation. The project was formally cancelled earlier in 2020. This has created the perception by many in the gas industry that most future interstate pipeline expansion projects in New York State would be blocked by the same circumstances.

Challenges with the NESE and other large infrastructure projects have caused gas shortages at the city gates of the Downstate New York gas utilities. At first glance, this has little to do with geo-targeted DSM since geo-targeted DSM is aimed at tackling peak hour constraints on distribution system branches, while Downstate New York utilities sought to address a daily delivery shortage at the supply points into their system (i.e. at the city gates). However, the challenges with the NESE project and its eventual abandonment have driven gas utilities in Downstate New York to consider NPS to address the forecasted shortages at their city gates. These efforts have drawn both public and PSC attention to long-term gas capacity planning and NPS.

Public attention increased because of the proliferation of moratoria on new gas connections (*firm* gas connections) in various areas of New York State. The long-term growth trends in natural gas demand both in New York State and neighboring states combined with the challenges with planning and building new interstate pipelines have been key drivers to the moratoria of new gas hookups. For instance, ConEdison and National Grid have declared moratoria in various areas of their service territory. In some areas, these moratoria have since been rolled back by the PSC, however they are still subject to increasing public and regulatory attention on long-term capacity planning and NPS.

New York Energy Institutions

New York State is one of the leading jurisdictions in North America when it comes to innovative energy solutions including but not limited to DERs. New York has built up institutional capabilities over time not only within its regulated electric and gas utilities, with New York Independent System Operator (NYISO) and the PSC, but also with several key organizations and institutions that are discussed below. The existence of these strong energy institutions has facilitated acceptance and development of NPS programs in the State.

- New York State Energy Research and Development Authority (NYSERDA) is a public-benefit corporation with a long history of providing objective information, analysis and technical expertise to promote EE and clean energy solutions. NYSERDA will coordinate with utilities, to deliver EE programs and plays a key role in many of the critical policies that are encouraging and sustaining the energy transition. There is no direct equivalent to NYSERDA in Ontario.
- The Reforming the Energy Vision (REV) is an important New York State policy launched in 2014 to build an integrated energy network (electricity, gas and other fuels) able to harness

the benefits of the central grid with clean and locally generated power and DERs. REV is meant to reorient both the electric industry and the ratemaking paradigm towards a consumer-centered approach to harnessing technology and markets.[10] The REV is consistently cited by electric and gas utilities, stakeholders and the PSC as a key driver for decisions.

- The REV, through efforts from many stakeholders including the PSC, NYSERDA, the Joint Utilities of New York (JUNY), and the utilities, has enabled progress on DER and fostered growing numbers of NWS on the electricity side. Their efforts led to the routine consideration of NWS as part of a new approach to distribution system planning. This is relevant to NPS in that the PSC is following a similar path to enable NPS. However, it remains to be seen if the PSC and stakeholders will be successful to the same extent they were with NWS, given the idiosyncrasies of the gas industry compared with the electric industry.
- The JUNY is an association of six of the seven electric utilities in New York State. It was created to coordinate the utilities participation during the development of the REV policy. The JUNY have hosted and participated in multiple stakeholder meetings through the REV process to gather input and collaborate across many topics, such as customer programs, electric vehicles, data access, DER interconnections and DER market participation. The JUNY has been instrumental to the evolution of the electricity distribution system planning approach and toward developing NWS practices in the State. Although the Electricity Distributors Association plays some of the roles of the JUNY in Ontario, there is no direct equivalent to the JUNY in Ontario.
- The JUNY is composed of the electric divisions of the New York State utilities and does not focus on the gas sector, nor on NPS. However, the precedence of the JUNY could potentially inspire a similar structure to support the update of the approach to long-term gas capacity planning and NPS.

Recent Policy Directions

In 2019, in alignment with the REV, New York State passed the Climate Leadership and Community Protection Act (CLCPA). The CLCPA entails:

- The bolstering of the previous renewable energy portfolio standard from 50% of sourcing from renewable energy by 2030 to 70% from non-emitting sources by 2030 and 100% by 2040.
- Commitment to achieve a net-zero carbon economy by 2050, with 85% coming from local (i.e. in-State) reductions of emissions and only 15% from carbon credits from out of state.
- A statewide goal of reducing energy consumption by 196m GJ per year (185 trillion British thermal units or TBtu) from the State's 2025 forecast through EE improvements. 196m GJ represents 10.2% of the state total energy use in 2018.

As part of the CLCPA, electric utilities were given steep targets (and correspondingly substantial budgets) to promote the adoption of heat pumps in all sectors of the economy. This program is expected to naturally lend itself better to oil-to-electricity conversions, electric resistance heating-to-heat pump conversions, and new construction rather than gas-to-heat pump conversions because the economics of these conversions are more favorable. However, the scope of the activity is still uncertain with budgets and targets potentially being used to do gas-to-electricity conversions (i.e. perhaps in areas of high constraint on the gas distribution network).

[10] New York State, '2015 New York State Energy Plan', 2019 <https://energyplan.ny.gov/> [accessed 24 July 2020].

Before the Accelerated EE Order, Ontario's gas DSM was ahead of New York State in terms of realized gas savings (in % of sales) and had a similar cost of acquisition of the savings (in $CAD). With the new Accelerated EE Order, New York State will surpass Ontario in terms of gas savings targets. Moreover, the New York State gas utilities were given more budget on a per-unit-saved basis to achieve their targets compared to Ontario utilities. Gas and electricity retail rates in Downstate New York are double those of Ontario, which significantly reduces the net cost of EE in Downstate New York, thereby making most EE technologies more economical for New York customers.

Photo by Robert Thiemann on Unsplash

Carbon Policy

In New York State, much of the recent policy activity has been driven by a commitment by the State to address climate change. By and large, the policy direction from the REV, the CLCPA and now New Efficiency New York (and the corresponding Accelerated EE Order) has been clearly laid out and consistent with climate change policy.

In Ontario, there has been far less clarity surrounding decarbonization. After the Cap and Trade Cancellation Act of 2018,[11] the Government of Ontario published a "Made-in-Ontario Environmental Plan"[12] that addressed a wide array of environmental considerations at a high-level. OEB staff have been working on two stakeholder consultation initiatives on DERs,[13,14] and OEB staff recently published a Staff letter on behind the meter battery electricity storage.[15] The IESO is making a laudable effort on working on thought leadership pieces, is considering possible market reforms to reduce barriers to DER penetration, and is implementing a high-profile NWS pilot project to serve as a test bed for interoperability across the transmission and distribution node (i.e. the transformer station). Even with the recent progress and policy direction, Ontario is still lagging in comparison with that of New York State with respect to DERs, energy efficiency, and decarbonization.

NPS and Long-Term Gas Capacity Planning

The forecasted gas shortages in New York State, mainly in Downstate New York but also in a few other areas in the State like the Capital Region, have led the gas utilities and the PSC to pay greater attention to long-term gas capacity planning. Stakeholders have also requested

[11] Province of Ontario, 'Cap and Trade Cancellation Act, 2018, S.O. 2018, c. 13', 2018 <https://www.ontario.ca/laws/statute/18c13> [accessed 3 September 2020].
[12] Ontario Ministry of the Environment Conservation and Parks, *Preserving and Protecting Our Environment for Future Generations – A Made-in-Ontario Environment Plan*, 2018 <https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf>.
[13] Ontario Energy Board, 'Responding to Distributed Energy Resources (DERs)', 2020 <https://www.oeb.ca/industry/policy-initiatives-and-consultations/responding-distributed-energy-resources-ders#:~:text=The OEB is initiating a,sector evolution can be realized.> [accessed 30 July 2020].
[14] Ontario Energy Board, *Utility Remuneration and Responding to Distributed Energy Resources Board File Numbers: EB-2018-0287 and EB-2018-0288*, 2019 <https://www.oeb.ca/sites/default/files/Ltr-UR-RDER-Refreshed-Consultation-20190717.pdf> [accessed 30 July 2020].
[15] Ontario Energy Board, *Ownership and Operation of Behind-the-Meter Energy Storage Assets for Remediating Reliability of Service*, 2020 <https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-ownership-of-BTM-storage-20200806.pdf>.

better alignment with the State's climate policy direction, including the CLCPA, and are seeking the inclusion of NPS (particularly EE, gas DR, and electrification) as a routine option to compare against traditional gas infrastructure investments – not only interstate pipelines to city gates, but also infrastructure investments on gas distribution systems.

Meanwhile, gas utilities in Downstate New York have relied on short-term peaking contracts and trucked CNG injection for the past few years to meet growth in peak demand and will continue to do so for the foreseeable future to ensure the reliability of their distribution systems. They are cautious of the risks associated with these types of solutions (e.g. road congestion delaying CNG delivery, price volatility and availability risks) and are seeking guidance on what constitutes an acceptable level of risk.

The PSC has undertaken a proceeding[16] that is intended to lead to better long-term planning practices in the State. A general expectation is that the Gas Planning Procedures proceeding should provide orientation regarding how NPS can be routinely integrated into gas planning in the same way NWS has been integrated into electricity distribution system planning. While New York State gas utilities have the precedent of NWS, they have invested in far less research and fewer and more modest pilot projects to support the growth of NPS efforts.

III. Conclusions

1) ***Overall, ICF found little progress on implementation of NPS, including development of geo-targeted EE, gas DR, and targeted gas-to-electricity conversion efforts in North America outside of New York State since the 2018 ICF study was completed.***
2) ***In New York State, ICF found that the utilities have made relevant progress in the development of NPS in terms of long-term capacity planning and analysis (e.g. National Grid Long-Term Capacity Planning reports) and pilot projects (ConEdison's gas DR pilot projects).***
3) ***Recent and upcoming progress on NPS in New York State promises to provide guidance on how to tackle many of the challenges associated with implementation of NPS, including treatment of issues related to utility remuneration and return on investment for different types of NPS.***
4) ***Ontario differs from New York State on many of the aspects that determine the value of NPS. Despite these differences, the experience in New York State represents a valuable source of information and best practices regarding NPS for Ontario utilities.***
    a. ***These differences include fundamentally higher energy costs in New York State, which tend to improve the economics of NPS options in the State. Demand in New York State also tends to be peakier than in Ontario, which increases the costs of conventional pipeline capacity relative to NPS options. Both factors improve the economics of NPS options in New York relative to Ontario.***
    b. ***The differences between Ontario and New York also include fundamental differences in the availability of natural gas pipeline capacity, the lower cost of infrastructure development in Ontario, the integration between the power and natural gas industries, both from a corporate and a regulatory perspective, and the nature of the natural gas load. These differences impact the need for and***

[16] NY Public Service Commission, *CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2BE6F1CE-5F37-4A1A-A2C0-C01740962B3C%7D>.

relevance of NPS in the two jurisdictions, and also explains the differences in NPS development timelines.

1. Background and Methodology

In 2018, ICF completed the 2018 IRP Study for Enbridge. The 2018 IRP study assessed the viability of employing targeted energy efficiency as an alternative to natural gas distribution system reinforcement infrastructure projects.[17]

As part of the 2018 IRP study, ICF conducted a literature and best practices review to assess whether or not and how other leading North American utilities were using EE to address system capacity constraints as an alternative to investments in new pipeline capacity. The 2018 review[18] focused on experience using DSM and demand response (DR) programs to reduce the need for infrastructure investment. [19] ICF also reviewed electric utility experience with utilizing energy efficiency[20] and DR in the facilities planning process.

At the time, ICF found that, while DSM and DR programs by electric utilities to reduce the need for new generating capacity and transmission capacity had been underway for many years, there was only limited experience deferring gas distribution system infrastructure through the use of similar programs. ICF found that several other natural gas utilities had started looking into the potential impact of DSM programs on system infrastructure requirements. However, these efforts were in the early stages. ICF was unable to identify a natural gas utility in any other jurisdiction that had implemented geo-targeted DSM programs to actively avoid investing in pipeline infrastructure in specific areas.

ICF was also unable to identify any natural gas utilities outside of Ontario that explicitly considered the impact of DSM programs on peak hour or peak day demand. Rather, savings from DSM programs were found to focus on annual savings. The impacts of DSM on infrastructure planning were assessed as annual demand reductions, rather than the peak hour or peak day requirements that drive the facilities planning process.

Enbridge's 2018 IRP study focused on geo-targeted energy efficiency to defer or avoid infrastructure investment on the gas distribution network.

Given recent developments in New York State, it was appropriate to broaden the scope to other non-pipe solutions (NPS). Additional NPS options beyond geo-targeted EE are discussed in Section 2.

Since this jurisdictional review was completed, natural gas utilities have continued to carry out related research and analysis and to pursue non-pipe solutions (NPS) pilot projects.[21] Enbridge retained ICF to complete an updated jurisdictional review to assess recent developments in the use of NPS to alleviate the need for new investments in supply-side infrastructure. This study includes an update of the previous jurisdictional review and consultations completed in 2017

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[17] ICF, *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report*. Completed on behalf of Enbridge Gas Distribution and Union Gas Limited

[18] Most of the research for the jurisdictional review of the 2018 study was completed in 2017

[19] The impact of EE on transmission-level facilities was out of scope for the 2018 IRP study.

[20] Electric utilities in Ontario refer to energy efficiency as Conservation and Demand Management (CDM) but energy efficiency is typically referred to as Demand Side Management (DSM) by most electric and gas utilities across North America (i.e. including the natural gas utilities in Ontario). For purposes of this report, all traditional annually focused DSM is referred to as energy efficiency or DSM, whether pertaining to electricity or natural gas. The terms have been used interchangeably.

[21] Alternative solutions to permanent supply-side infrastructure have come to be known as NPS to capture their function in serving as alternatives to traditional gas infrastructure reinforcements or extensions. At Enbridge, these NPS are known as integrated resource planning alternatives (IRPAs) but the NPS acronym is used throughout this Study.

and published in 2018.[22] The jurisdictional review update was intended to highlight any progress that has been made on NPS by other North American utilities since 2017.

ICF and Enbridge were aware of relevant progress by utilities in New York State. The New York State utilities are considered to be at the forefront of NPS efforts. For this reason, the update to ICF's jurisdictional review placed additional emphasis on New York State. This element of the review examined parallels and deviations in the circumstances and motivations for NPS considerations between New York State and Ontario. Given that the State of New York is viewed as a leader in NPS and Ontario's progress is being reviewed in relation to New York State, ICF also completed a thorough comparison of the two jurisdictions to better appreciate the potential to apply the New York State experience to the use of NPS in Ontario.

ICF conducted a high-level analysis of the differences between the legislative mandates and regulatory regimes in New York State and Ontario, such as differences in the regulatory and rule-making structures, carbon pricing mechanisms and targets, emission reduction policies and targets, clean energy standard programs, and resource-specific procurement targets to support mandates. A brief overview of the legislative changes and regulatory directions that led to present conditions within each jurisdiction is also presented.

ICF's research approach was largely based on extensive desk research and semi-directed interviews with relevant utilities including but not limited to New York State gas utilities.

[22] ICF, *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment – Final Report*. Completed on behalf of Enbridge Gas Distribution and Union Gas Limited.

2. Non-Pipe Solutions: Definition and Drivers

During the jurisdictional review, ICF found that the definition of NPS varies depending on the utility and jurisdiction.

This section presents a broad definition of NPS that will be used throughout this report. This definition is based on the range of definitions used in other jurisdictions.

Exhibit 1 summarizes the range of technologies generally considered to represent NPS. As summarized in this exhibit, NPS may include any of the following: energy efficiency (which is being used interchangeably in this report with demand-side management or DSM), gas DR programs, and fuel switching to electric heat pumps (or electrification). DSM can be either geo-targeted DSM, or general DSM. NPS also frequently includes distributed infrastructure options, such as CNG and LNG, that are installed locally to supplement natural gas supplies on constrained sections of the natural gas distribution system. *Distributed* infrastructure options are different from large infrastructure projects – such as new transmission pipelines, existing transmission pipeline upgrades, or large storage facilities (LNG or underground caverns) outside of city gates.

Exhibit 1 NPS as Defined in this Report

Distributed Infrastructure Options

Liquefied Natural Gas (LNG)
Facility on land, on a barge or offshore with natural gas stored in cooled down liquid. The LNG must be delivered to the facility, and must then be gasified before being injected into the pipe network.

Compressed Natural Gas (CNG)
Facility on land with natural gas stored under high pressure in gaseous form. The CNG must be delivered, and is often trucked in. The CNG is decompressed before being injected into the pipe network.

Renewable Natural Gas (RNG)
Biomethanization facility that converts organic matter (often bio waste) into biogas. The biogas mainly contains methane but also other gases, some of them undesirable. The biogas is cleaned before injection into the pipe network.

In certain jurisdictions, NPS entail these three options, and exclude EE, DR, and electrification. In other jurisdictions, it is the other way around.

No-Infrastructure Options

Energy Efficiency (EE)
Gas consumption reduction in multiple buildings through a variety of technology upgrades and/or behavioural changes. Typically delivered in the form of an incentive program aimed at convincing multiple customers to implement the upgrades.

Gas Demand Response (Gas DR)
Curtailment of gas demand over a specific set of hours during peak demand periods through an automated system or a planned schedule. Gas DR can be used to alleviate day-long constraints at city gates or hourly constraints on the distribution system.

Electrification (Gas to Electricity, G2E)
Conversion of space, water heating or even food service gas end-use to electrotechnologies on a geo-targeted basis to reduce peak day demand on parts of the natural gas distribution system. The electrotechnologies of choice to alleviate gas winter peak are air-source and ground-source heat pumps.

EE, DR, and electrification can be **geo-targeted at specific constrained segments of the distribution,** focused on the broader distribution service territory.

Gas DR has the same purpose and is added to the traditional "interruptible rates."

Distributed infrastructure options are different because they are located closer to the demand and the projects are smaller in cost and capacity, making them less at risk of becoming stranded assets if the demand growth does not materialize as forecasted.

A few jurisdictions are also exploring renewable natural gas (RNG) and power-to-gas as NPS. The role of these supply sources is relatively limited for practical reasons. The potential for these types of facilities to serve constrained sections of a natural gas distribution territory is limited by land occupation, population density, and the availability of locally-sourced feedstock.

Gas DR and Interruptible Rates

Natural Gas DR programs are starting to receive more attention as an NPS option, in addition to, or sometimes replacing interruptible rates. In a sense, the gas industry has been implementing an approach to peak load curtailment, using interruptible rates, for quite some time. Interruptible rates were originally designed to improve load factor by “filling valleys” – or increasing demand during off-peak periods – to amortize infrastructure costs on larger natural gas sales, as well as providing an approach to minimizing the need for high cost capacity during peak demand periods. Interruptible rates provide an incentive to customers to curtail demand during peak demand periods, with interruptible rate customers typically required to shift to alternate fuels when they are asked to do so.[23]

What is new, is that utilities are starting to deploy new approaches to peak demand curtailment, “gas DR”, by leveraging advanced thermostats, behavioral programs, and gas curtailment programs that differ from the traditional “interruptible rates” in that they shift natural gas demand that has traditionally been served with firm service away from natural gas during peak periods.

As an example of an alteration to traditional interruptible rates, a DR program in the commercial and industrial (C&I) sector would offer a “firm rate” with a voluntary curtailment. A participant in a C&I DR program would have the right to firm services but is rewarded for curtailing its peak demand upon request. A participant in an interruptible rate does not have the right to a firm service and gets penalized for needing gas despite being curtailed. It is a small nuance, but a C&I DR program could potentially expand the pool of C&I customers that agree to curtail their load above those that were already willing to adopt an interruptible rate.

Another DR approach is “clean DR”. In other words, a DR approach that would avoid the use of a fossil fuel-based back-up (petroleum product) to supply space, water, or process heating during curtailment periods.[24]

As this report demonstrates, these technologies have been reviewed by different utilities across North America, some of which have included pilot studies. Gas DR remains uncommon and mostly untested in its potential to respond to the immediate needs of gas utilities. Utilities such as ConEdison and National Grid are currently conducting DR pilots. If this trend continues, gas DR may have growing relevance in NPS considerations given its ability to specifically curtail peak demand (both daily and hourly). However, the value of a DR program is dependent on the

[23] The benefit of relying on a back-up fuel is that the gas service interruption can last for an large amount of time – i.e. a full day, or several days – with the only constraints being the size of the on-site fuel tank and delivery time for more fuel. For instance, interruptible rate customers at Enbridge Gas require a secondary fuel train at site to be eligible.

[24] “Clean DR” was introduced by the PSC at the start of a recent proceeding on gas planning that we will discuss in the remainder of this report. The PSC did not define it, however, except for mentioning that it would avoid the combustion of a petroleum product as a back-up energy source. Illustrative examples that ICF can offer entail: service interruption that would cause only a in level of comfort that the customer would agree to because it is short and/or imperceptible, the use of a biofuel, switching to resistive electric heating and/or a form of thermal storage (perhaps electric thermal storage).

value of the peak demand reduction, which varies widely by jurisdiction. In regions with high cost capacity requirements, or limited ability to increase capacity to meet growth in demand, such as parts of New York State and New England, gas DR will be much more economic than in jurisdictions with lower cost capacity options, such as Ontario.

Electrification as an NPS

Gas to electricity conversion is a relatively new trend in NPS. Typically, the electrification that has been seen during this study is through the deployment of air-source and ground-source heat pumps due to the expected environmental benefits associated with the use of renewable power.

ICF found that the key drivers behind adding electrification to the toolbox of NPS come from: clear decarbonization policy direction that includes a rapid decarbonization of the electricity grid, abundant funding to incentivize the conversions, presence of a pool of buildings that heat with resistive electric heating systems and/or that heat with delivered fuel (heating oil or propane), and critical pending natural gas shortages forcing gas utilities to extreme measures – such as moratoria on new firm gas connections.

Upstream Constraints versus Downstream Constraints

For most of the investments in new natural gas infrastructure, the critical demand factor determining whether a new facility is required is the balance between peak capacity of the existing system and peak demand. When projected peak demand (based on the peak hour or peak day demand) approaches or exceeds the peak capacity of the existing system, the utility typically would develop plans to expand its capacity by building new pipelines or otherwise increase the capacity of its existing transmission or distribution system in order to meet the growth in peak demand.

This can occur on a system-wide basis, where the limits on capacity reflect the ability to deliver firm natural gas service to the utility city gate; or it can occur where there are limits on system capacity downstream of the city gate, where the gas supply is available but the ability to move the gas supply to where it will be needed is not available.

Downstream Constraints/Geo-targeted: The 2018 IRP Study focused on *geo-targeted* EE (as opposed to broad-based EE), which is essentially the use of EE to alleviate peak constraints on specific branches of the distribution system. In other words, ICF had focused on constraints that were **downstream** of city gates on the distribution system. Downstream constraints are often driven by hourly rather than daily peak demands and tend to be for a few hours at a time. Addressing these constraints requires a thorough understanding of load growth even in the low-diversity[25] branches of the distribution system, and a thorough understanding of the "load shape" of the gas savings, hour by hour.

Upstream Constraints: In 2020, we found that NPS has been used not only to describe geo-targeted DSM but also to characterize EE and DR used to alleviate peak period constraints at the LDC city gates (i.e. **upstream** constraints) caused by congestion on transmission pipelines (including interstate pipelines) rather than distribution pipes. Upstream constraints tend to limit

[25] The level of diversity is defined and measured by the variety of end-uses and gas-using equipment, and the number of customers needing gas. A large population of heterogeneous customers has a high diversity level. A small population of homogeneous customers has a low diversity level. Low diversity level means more variability of the load and more challenging predictability of the load, both of which makes distribution infrastructure more challenging to plan for – especially in the long term.

the ability to deliver additional natural gas to the city gate for one or more days during winter cold snaps.

The discussion about NPS being used to alleviate upstream constraints has been less about the hourly load profile of the savings, and more about how much "incremental" EE, DR, and electrification (*incremental* to pre-existing broad-based DSM committed targets and corresponding funding) ought to be planned and funded to avoid purchasing capacity on new upstream transmission pipelines.

This means a gas utility avoiding new transmission pipelines might simply need incremental DSM offered to all customers in the portion of its service territory served by a specific city gate. Typically, it would not have to discriminate by geolocation with its service territory.[26]

[26] An LDC service territory may be served by more than one Citygate, where one or more of the city gates face supply constraints. In these cases, only a portion of the service territory may face constraints. The constraints into Westchester County on the Con Edison system in New York State represent perhaps the most widely known example. In this case, part of the system could be targeted with a broad-based DSM program.

3. Recent Developments in Natural Gas IRP and Non-Pipe Solutions

When ICF completed the 2018 IRP study, it did not identify any natural gas utilities that were actively factoring in the impact of DSM programs on peak hour or peak day demand forecasts on their facilities planning. A few gas utilities had begun to consider these impacts, but their efforts were still in the early stages. ICF followed up with several of these utilities to document their progress since the 2018 IRP study to gain a better appreciation of the drivers, approaches, success factors, and lessons learned relating to NPS considerations.

Based on our research, ICF was able to identify several natural gas utilities that are considering the impact of EE and gas DR programs on peak hour or peak day demand forecasts they use for their facilities planning. However, pilot projects related to NPS have been modest to date. Nonetheless, there is motivation, particularly in the State of New York, to convert these pilot projects into full-fledged NPS offerings due to supply constraints.

ICF consulted with Central Hudson (Upstate New York), Columbia Gas (Massachusetts), ConEdison (Downstate New York), NYSEG (Upstate New York), NW Natural (Oregon), and FortisBC (British Columbia).

British Columbia, FortisBC

FortisBC owns and operates approximately 47,500 km of natural gas transmission and distribution pipelines across BC, providing natural gas to over 1 million customers in the province. When ICF consulted with FortisBC staff in 2017, they noted that the utility was not facing any major pipeline constraints at the time, with the one exception of the interior Kelowna region. The lack of major constraint is a result of major facilities investments that had been previously completed in its service territory. For instance, a previously identified constraint on Vancouver Island had been resolved with a large LNG storage tank and liquefication project.

FortisBC staff noted that the utility has a regulatory requirement to demonstrate that a system need cannot be met by DSM prior to making a facility investment. However, they had not considered DSM as an alternative to facility investments to account for resource optioning within the context of IRP planning due to a lack of evidence that DSM could reduce peak demand. DSM was also not assessed at a detailed level for integrated resource planning as an alternative to infrastructure due to concerns related to the reliability of peak demand impacts as well as the timelines associated with these projects.

In 2017, Fortis indicated that they had not explored geo-targeted DSM options since their primary focus was on assessing annual energy savings rather than peak demand reductions. However, FortisBC was working on the development of load profiles to translate consumption savings into an annual peak. This approach was designed to leverage the knowledge around electric load profiles in terms of the major thermal end-uses, and then use SCADA systems to calibrate the end-use demand profiles.

When ICF consulted with FortisBC staff in July 2020, they indicated that their position had not materially changed since 2017. In part, this is due to the availability of gas resources within its territory from the Western Canada Sedimentary Basin and lack of reliance on interprovincial or interstate pipelines.

The population density in BC is lower than many of the other jurisdictions, including New York State and Ontario. As such, the siting of new supply-side reinforcement solutions (e.g. new compressors, pipelines, or storage) is simpler and the cost is lower. FortisBC is more challenged with potential new industrial facilities wanting to connect to its system (or with transmission pipelines) than with natural growth due to economic and demographic trends.

FortisBC also noted the challenges in making the case for AMI gas meters needed to accurately assess changes in demand during peak usage periods. Nonetheless, FortisBC recently revealed plans to file an application with the BC Utility Commission (BCUC) in Q4 2020 for approval of installing more than 1 million AMI meters at homes and businesses across its service territory from 2022 to 2026.[27] In addition, FortisBC indicated that they have investigated submetering options and other ways to better understand what is happening at the end-use level during peak demand events. Their research identified a limited number of viable options.

FortisBC conducts granular bottom-up load forecasting for its long-range (20 year) demand forecasts and monitors potential constraints and supply solutions. As per its latest Long Term Gas Resource Plan, FortisBC is monitoring a small number of potential system constraints; primarily in the Okanagan region, where capacity may be reached in 2022 and on the Vancouver Island Transmission System, where system capacity may be reached in 2028. In both cases, it is studying a range of supply-side reinforcement options.[28]

FortisBC noted that their formal method of determining peak demand involves a customer-by-customer analysis of the relationship between peak demand and weather based on historically observed trends. Nonetheless, the utility is testing the use of load profile analysis to project its system peak compared with annual demand. Their analysis has been relied, in part on Enbridge's 2018 IRP Study. However, they have not completed any measurements to validate the analysis. For this reason, and because of the relative ease and low cost of developing supply-side reinforcement solutions in their jurisdiction, FortisBC is not actively pursuing NPS or geo-targeted DSM as alternatives at this time. However, BCUC has directed FortisBC to "provide an update on its investigation of opportunities for DSM to be used to cost-effectively defer infrastructure investments in its next Long Term Gas Resource Plan",[29] which is due to be submitted in March 2022.

On the left-hand side of Exhibit 2 are the challenges that were highlighted in Enbridge's 2018 IRP Study. On the righthand side of Exhibit 2 is FortisBC's updated perspective on these challenges based on an interview conducted by ICF with a representative from FortisBC in July 2020.

Exhibit 2 Perspective on NPS Challenges from FortisBC

Challenge	
Reliability	The impacts of geo-targeted DSM are still being questioned due to the lack of metered load profiles at the end-use and technology level.
Lack of metered data	While FortisBC is now moving in the direction of gas AMI, they have yet to start rolling out the infrastructure, let alone collecting the data that would generate load curves.
Additional research	FortisBC is of the position that more research is needed to rely on geo-targeted DSM projections.
Changing lead times for projects	FortisBC did not state a position on the minimum lead time before an infrastructure has to be upgraded that would suffice to consider geotargeted EE.

[27] FortisBC, 'Advanced Gas Meters', 2020 <https://www.fortisbc.com/about-us/projects-planning/natural-gas-projects-planning/advanced-gas-meters> [accessed 31 July 2020].
[28] FortisBC, *2017 Long Term Gas Resource Plan*, 2017 <https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/171214_fei_2017_ltgrp_ff.pdf> [accessed 31 July 2020].
[29] BCUC and FortisBC Energy Inc., *2017 Long Term Gas Resource Plan: Decision and Order G-39-19*, 2019 <https://www.bcuc.com/Documents/Proceedings/2019/DOC_53485_Decision-and-G-39-19-FEI-2017LTGRP.pdf> [accessed 18 August 2020].

Challenge	
Principle of universality, cross subsidization	There has been some discussion on the matter in past interrogatories, but the topic was never fully explored due to the remoteness of the possibility to undertake geo-targeted DSM or other NPS
Changes in the Infrastructure Approval Process for Targeted DSM	FortisBC requires approval for any new DSM programs. There is some concern that the approval of a geo-targeted DSM program would not come in time to allow it to adjust the calendar of a supply-side reinforcement project, but FortisBC staff noted that they could likely gain approval for a program or pilot within a year if they can demonstrate an impact.
Appropriateness of cost-effectiveness testing	Discussion so far have only been on the sufficiency and accuracy of the assumptions used for quantifying the costs of the supply capacity.
Overlap with broad-based DSM	This has not been a consideration to date.
Utility remuneration and incentives to pursue geo-targeted DSM	FortisBC amortizes regular DSM spending over 10 years based on its weighted average cost of capital. It thereby earns its regulated return on equity just as if it had deployed regulated distribution infrastructure.

Oregon, NW Natural

Headquartered in Portland, Oregon, NW Natural serves 750,000 natural gas customers in 140 communities in Oregon and Southwest Washington. NW Natural collaborates with the Energy Trust of Oregon (ETO) for the delivery of its broad-based DSM programs in Oregon. The utility contributes ratepayer-funding for DSM and provides assumptions that feed into the ETO's planning. Programs, DSM forecasts, and targets are all set by the ETO, along with program delivery.

The NW Natural Gas IRP typically includes DSM as a key resource to meet forecasted load. Their latest IRP in 2018[30] also considered traditional storage, CNG, RNG, and Power-to-Gas (i.e. hydrogen injection) as options for meeting forecasted load.

Over the years, NW Natural has been able to enhance its collaboration with the ETO and has streamlined the processes to develop more accurate DSM forecasts and to improve the quantification of the potential DSM benefits. In its past IRPs, NW Natural would plan the supply infrastructure, compute the avoided cost, and receive load alleviation forecasts from the ETO, which they would then include in their IRP forecasts. This process did not consider the impact of load alleviation forecasts on the avoided cost economics, which by extension would also impact the DSM forecasts themselves. More recently, NW Natural has been able to work iteratively with the ETO in a way that allows them to converge on a more accurate avoided cost of capacity and resulting DSM forecast.

In 2017, NW Natural had indicated plans to collaborate with the ETO to include projections on the impact of peak savings. For the 2018 IRP, the ETO had projected the impact of peak savings both for a design day and for a peak hour over a time horizon of 20 years. The ETO estimated a factor of 1.40% of peak-day savings compared with annual savings, and a factor of 0.09% of peak-hour savings compared with annual savings.

In 2017, NW Natural expressed the need to address the gaps related to the reliability of targeted DSM peak hour savings, the cost and timing at which the savings accrue, and the methodology

[30] NW Natural, *2018 Integrated Resource Plan*, 2018 <https://www.nwnatural.com/uploadedFiles/NW Natural 2018 IRP.pdf> [accessed 18 August 2020].

for measurement of the savings. ICF's recent interview with NW Natural staff suggested that NW Natural's views persist in 2020.

NW Natural is currently in the process of conducting a geo-targeted energy efficiency pilot project, nicknamed "GeoTEE", in close collaboration with the ETO. The project is designed to obtain the required measured data needed to perform the necessary analysis for consideration of geo-targeted energy efficiency as a viable option for deferral and avoidance of future distribution system investments. The GeoTEE pilot project includes marketing and customer engagement pieces for a certain segment of NW Natural's distribution system to promote EE through existing ETO broad-based EE programs.

It was critical to the experimental design of the project to select a loop of the distribution system that can be more easily isolated for the pilot. NW Natural installed one AMI meter on the loop for measurements.

Results from Financial Year (FY) 2018/2019 were delayed due to issues relating to a faulty meter. NW Natural is in the process of analyzing data from FY2019/FY2020. They expressed concerns about the potential impact of COVID-19 on the dataset, but they have not yet confirmed whether this was indeed an issue of real concern. To date, no results have been made available from this pilot project.

Exhibit 3 provides a 2020 update of NW Natural's perspectives on the key challenges that were uncovered during the 2018 IRP.

Exhibit 3 Perspective from NW Natural

Challenge	
Reliability	NW Natural expressed concerns regarding the reliability of the peak demand impacts of DSM. Testing the reliability of geo-targeted EE is one of the goals of their GeoTEE pilot.
Lack of metered data	Metering data was a concern for NW Natural in 2017 that remains today. NW Natural has yet to find an AMI meter that can measure less than 1 therm accurately. They are currently in the process of testing different technologies.
Additional research	NW Natural's GeoTEE pilot seeks to address additional related research inquiries. One of the goals of the pilot is to develop the supply curve on a $ per unit peak demand impact basis and to inform the modeling of geo-targeted DSM in future IRPs.
Changing lead times for projects	Did not provide feedback on this point but the fact that ETO delivers programs on behalf of NW Natural may complicate the timing in their service territory.
Principle of universality, Cross subsidization	The topic has been posed in prior interrogatories, but they have no current position or response to this issue.
Changes in the Infrastructure Approval Process for Targeted DSM	Investigating the value of delaying a project versus fully avoiding it and how to evaluate that for every project.
Appropriateness of cost-effectiveness testing	Monitoring progress on this front in other jurisdictions.
Overlap with broad-based DSM	NW Natural's GeoTEE pilot project includes marketing and customer engagement pieces for a certain segment of NW Natural's distribution system to promote EE through existing ETO broad-based EE programs.

New York, ConEdison

Consolidated Edison Company of New York, Inc. (herein ConEdison) delivers natural gas to approximately 1.1m customers in Manhattan and several boroughs of New York City. Gas is delivered by interstate pipelines to ConEdison at various city gates inside or near its territory.

When ICF spoke to ConEdison in 2017, they were in the process of evaluating gas DR programs to reduce peak daily natural gas demand and defer capital investments. They were also in the process of rolling out a full-scale AMI project, including encoder receiver transmitter (ERT) gas modules for gas meter, which had reached 41% of completion of ERT module installation at the end of April 2020[31]. ConEdison's ERT modules connect to existing gas meters and will transmit hourly interval data on gas consumption on a daily basis.

ConEdison's peak demand had increased by 30% since 2011, and their forecast predicted another 20% growth over the next 20 years. There are still many growth drivers in the gas load including: customers preferring the environmental benefits of gas, community clean heat programs that introduced requirements for customers to switch over from heating oil, and the value proposition of gas in terms of its reliability, convenience, and price in place of heating oil, propane, and electricity.

Even before the 2018 IRP Study, pipeline capacity coming into ConEdison's service territory was fully contracted, and proposals for new pipeline projects were encountering increased difficulty in securing necessary preconstruction permits. Most notably, Section 401 Water Quality Certification from the New York State Department of Environmental Conservation has been challenging to secure.

ConEdison has been facing supply shortages at a few of its city gates as well as on certain major transmission mains within its service territory. As such, ConEdison's needs for NPS applies to broad areas of its service territory as opposed to specific areas, and there is a need for NPS to curtail gas requirement on a full design day as opposed to only a few peak hours. In other words, the focus is on daily (24-hour) transmission and supply constraints as opposed to hourly distribution system-level constraints.

The continued rise in demand has strained the capacity on the interstate pipelines serving ConEdison, making the utility reliant on short-term delivered services contracts for more of its peak-day natural gas supply. As early as 2017, ConEdison was uncomfortable with its increased reliance on short-term solutions including short-term peaking contracts and distributed resource options like CNG injection. They see significant risk associated with the market price fluctuation and ongoing availability of short-term capacity.

According to ConEdison: "*While an appropriate amount of Delivered Services can play an important role in a utility's pipeline capacity portfolio, undue reliance on Delivered Services should be avoided because of the risk that Delivered Services will not be available at needed levels in future years.*"[32]

It is worth noting that there has been no consensus yet between the utilities and PSC on what constitutes "excessive risks" related with short-term peaking solutions. One of the goals of the on-going PSC's long-term gas planning proceeding is to establish a common definition of what would constitute a "reasonable" versus "excessive" reliance on short-term solutions.

These challenges led to the January 17, 2019 announcement of a temporary moratorium on new firm gas customers[33]) in part of their service territory. This moratorium has since been rolled back based on the availability of additional short term delivered peaking services.

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[31] ConEdison, *Distributed Infrastructure Implementation Plan (New York, NY, USA, June 30, 2020)*, 2020 <https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/distributed-system-implementation-plan.pdf> [accessed 18 August 2020].
[32] ConEdison, *Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*, 2018 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA7C3D0CD-E2B3-4B42-807C-82B553AE63F9%7D> [accessed 31 July 2020].
[33] The moratorium did not apply to interruptible customers who do not contribute toward peak demand.

To address the growing concern of overreliance on short-term contracts and the moratorium, ConEdison is developing non-pipeline solution pilot projects with the long-term goal of reducing the need for new pipeline capacity. This effort is included as part of the Smart Solutions for Natural Gas Customers Program. The Smart Solutions program includes three non-traditional solutions to address customer gas needs:[34]

- Developing a Gas DR Pilot to reduce net customer demand during the entirety of a peak gas demand day
- Creating a gas innovation program for renewable alternatives to natural gas heating.
- Issuing a market solicitation for additional NPS on either the demand side or distributed infrastructure

ConEdison's DR Pilot was launched in the winter of 2018/19. It consists of a performance-based Gas DR Pilot targeting commercial and industrial customers and multi-unit residential buildings with central heating, and a residential thermostat direct load control (DLC) program, deploying both ConEdison's own fleet of advanced thermostats (also used for summer electricity peak curtailment) and a bring-your-own thermostat component. As part of the performance-based gas DR pilot, building operators are asked to pledge daily savings on peak days, are given advanced notice of the need to curtail their demand on the peak days, and are compensated based on performance.

Under the original (electric) direct load control program, there was a sign-up bonus of $115 ($85 USD) per thermostat. ConEdison added a one-time, up-front incentive of $34 ($25 USD) for enrollment in the DLC Gas DR Pilot. By the last event in the 2019/20 winter period, the DLC Gas DR Pilot had achieved enrollment of 2,817 thermostats.

ConEdison has provided two reports on the status of the Gas DR program. In the second status report for winter 2019/2020,[35] ConEdison reported the following:

- **C&I and Multi-unit residential building Performance-Based Gas DR Offering:** 309 customers pledged 78,675 m^3 of gas (2,886 Dth). ConEdison called one test and realized 54% of the pledged impact.
- **DLC Gas DR Offering:** Over 2,800 thermostats were enrolled in the program. The overall curtailment was an average reduction of 1,529 m^3 of natural gas (56.1 dth) per test event including the snapback effect[36], with results hovering between 0.38 m^3 (0.014 dth) and 0.76 m^3 of natural gas (0.028 dth) per thermostat. ConEdison found that a smaller setback of 1 deg F resulted in higher impact than more stringent setbacks because ConEdison found fewer cases of customers overriding the DR calls.

ConEdison plans to continue to run events and measure results on an annual basis to gather more data and to gain a better understanding about performance of gas DR.

In December of 2017, ConEdison issued a public tender for NPS from various proponents that would provide peak-day relief in key areas. Using the results of the solicitation, ConEdison developed a portfolio of NPS projects that met cost-effectiveness requirements. However, the tendering process did not lead to sufficient cost-effective options to avoid or defer the need for

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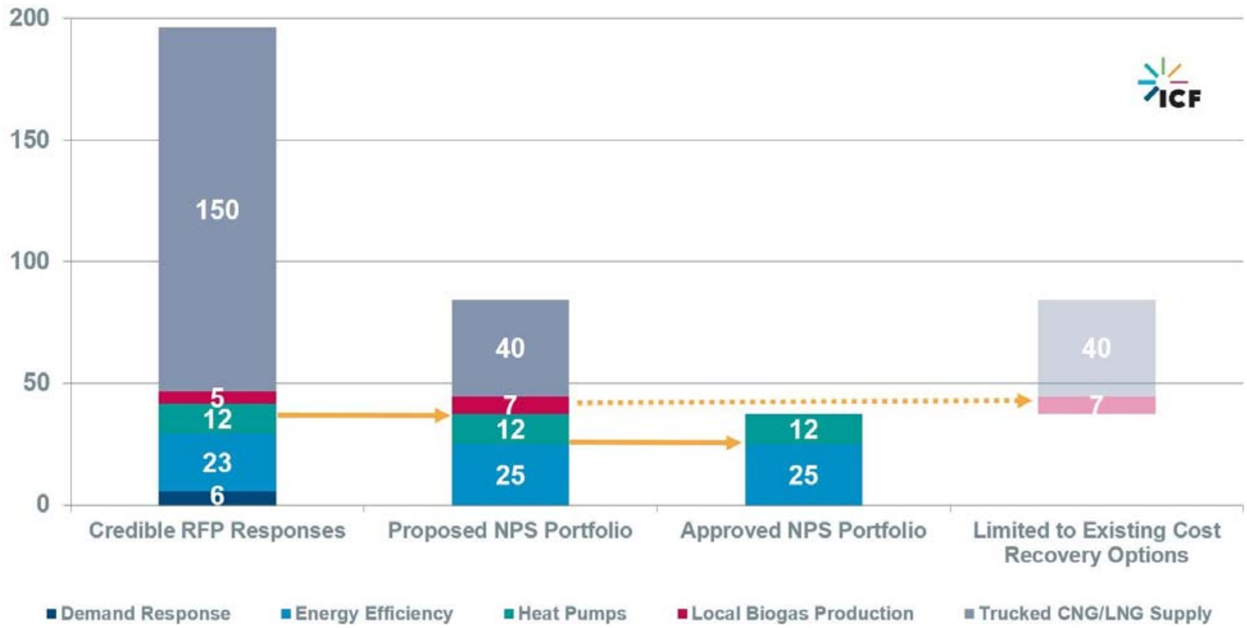
[34] ConEdison, *Gas Demand Response Pilot Implementation Plan, 2018-2021, Case 17-G-0606*, 2020 <https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/gas-demand-response-implementation-plan.pdf> [accessed 31 July 2020].

[35] ConEdison, *Gas Demand Response Report on Pilot Performance - 2019/2020, Case 17-G-0606 and Case 14-E-0423*, 2020.

[36] The snapback effect is an increase in energy demand that happens due to the synchronization of a fleet of asset because of a DR event. In other words, the entire fleet of heating equipment that was curtailed start at the same time and operate at full capacity simultaneously to bring back the space temperature at its original setpoint. There are many DR strategies to minimize and soften the snapback.

new interstate pipeline construction. Nevertheless, the effort resulted in a $412m ($305m USD) portfolio of projects, including a mix of EE and electrification as well as supply-side measures such as CNG and RNG, as shown in Exhibit 4. The portfolio was submitted to the New York Public Service Commission (herein PSC) for approval on September 28, 2018.[37]

Exhibit 4 Peak Day relief (1,000's of Dth/day) by Stage if NPS Process[38]



On February 7, 2019, the PSC ruled on the proposed NPS Portfolio, as illustrated in Exhibit 4, approving part of the proposed NPS Portfolio, while rejecting other parts. The $300.5m ($222.6m USD) portion of the proposal requested for EE and electrification was approved with conditions, while rejecting the $111.5m ($82.6m USD) portion of the proposal request for CNG/LNG trucking and RNG.

While the PSC agreed to a $300.5m ($222.6m USD) budget for the specified EE and electrification projects, it directed that this funding should come from an expanded energy efficiency budget that had been announced previously. In April 2018 NYSERDA and the PSC had published expanded energy efficiency targets for the state[39] and by December 2018 the PSC had passed an order formally adopting expanded energy efficiency budgets and targets for utilities.[40] The PSC order on the NPS portfolio instructed ConEdison to include the 'approved' $300.5m ($222.6m USD) budget and targets within the budget and plan it was scheduled to file in March 2019, as part of the separate proceeding expanded energy efficiency budgets. In effect, this was not new money for NPS, but the PSC approved the demand-side NPS measures because they aligned with the state's existing plans to significantly increase funding to both improve energy efficiency and drive heat pump adoption.

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[37] ConEdison, *Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program*.
[38] ICF, 'What Can We Learn from New York's Non-Pipeline Solutions Ruling?', 2019 <https://www.icf.com/insights/energy/non-pipeline-solutions> [accessed 31 July 2020].
[39] NYSERDA, *New Efficiency: New York*, 2018 <https://www.nyserda.ny.gov/-/media/Files/Publications/New-Efficiency-New-York.pdf> [accessed 20 August 2020].
[40] NY Public Service Commission, *CASE 18-M-0084 - In the Matter of a Comprehensive Energy Efficiency Initiative - Order Adopting Accelerated Energy Efficiency Targets, December 13, 2018*, 2018.

While most of the funding was tied up in additional cases, the PSC NPS order did allow ConEdison to get started on some pilot projects, through the approval of $40.1m ($29.7m USD) for the first year of the demand-side initiatives. ConEdison used the initial funding tranche to implement three one-year pilot programs:

- **Electrification program:** This pilot targeted residential customers in Westchester County for gas to ground-source heat pump conversions. ConEdison reported results that exceeded targets, largely due to the higher than anticipated count of participating homes (i.e. 60 participants).
- **Residential sector weatherization program:** ConEdison reported results that were lower than the targets for this program.
- **Electrification project:** This project was focused on a conversion to air-source heat pumps in a multi-unit residential building in the Bronx. The project was unsuccessful due to lack of suitable participants.

The PSC NPS order did not approve pilot projects for the local production of RNG, or the distributed LNG and CNG components (trucked into the City), arguing that these were distributed supply-side solutions and not NPS. As such, they were seen as part of normal distributor responsibilities to deliver reliable services to its customers. The PSC, while rejecting the funding requested for supply-side solutions through this NPS proceeding, noted that these projects should instead be included within ConEdison's existing capital program and/or included in ConEdison's upcoming rate filing.[41]

While some of the intervenors were comfortable with LNG and CNG, arguing that these solutions would be preferable to a new pipeline due to their modularity/incrementality, which reduces the risk of a stranding large assets if the demand growth was not to materialize according to the forecast, found that the shared savings suggested by ConEdison were inappropriate.[42] They argued that the proposed portfolio of NPS would fail to avoid the need for additional supply capacity to city gates and that the Petition lacked evidence that the proposed alternatives were an appropriate match to additional supply in terms of reliability (i.e. number of hours or days needed versus number of hours or days delivered by the NPS).

ConEdison had proposed an incentive approach to these NPS options based on a shared savings approach (70% of net benefits to ratepayers and 30% of the net benefits to the Company).

In order to complement its existing portfolio of NPS, ConEdison issued a request for information in January 2020 with a submission deadline of April 2020.[43] Proposals are currently being evaluated. ConEdison's goal is to explore new options not previously examined as part of the earlier solicitation. The utility hoped to see proposals for DR enablement (i.e. installation of related equipment and/or controls) to allow greater participation in existing gas DR programs or new programs for smaller customers. The 2020 RFI also solicited hydrogen pipeline-injection proposals (i.e. Power-to-Gas).

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[41] NY Public Service Commission, *Case 17-G-0606 Order Approving with Modification the Non-Pipeline Solutions Portfolio*, 2019 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B64CE307C-4FD6-4043-8BE2-A5F04C5080E8%7D> [accessed 31 July 2020].

[42] ConEdison also requested a true-up to actual costs that would split overruns or underruns 50/50. A similar approach is used for electric non-wire solutions projects.

[43] ConEdison, *Request for Information (RFI) Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief*, 2020 <https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-pipes/non-pipeline-solutions-to-provide-peak-period-natural-gas-system-relief-rfi.pdf?la=en> [accessed 31 July 2020].

On July 17, 2020, ConEdison filed a supply/demand analysis on areas of capacity constraints[44] in which it listed a number of solutions to address the its supply gap, including demand-side solutions, distributed/temporary supply-side solutions, adding compression to existing pipelines, as well as new routes for potential interstate pipelines.

Exhibit 5 presents the 2020 perspectives of ConEdison on the challenges that were uncovered during the 2018 IRP.

Exhibit 5 Perspective on NPS Challenges from ConEdison

Challenge	
Reliability	Reliability of NPS to result in peak hour reductions remains to be proven even after 2 years of history of the various NPS initiatives. ConEdison uses a derating factor (compared to a "pipe" solution) to address this concern.
Lack of metered data	ConEdison already has non-communicating interval meters installed for its large C&I customers. The utility is in the process of installing AMI meters (ConEdison selected including encoder receiver transmitter (ERT) gas modules that get attached to the gas meters for provision of hourly interval reading on a once per day basis[45]. However, the M&V approach for its residential gas DR program focused on smart thermostats was based on furnace runtime data from the thermostats. ConEdison noted that it was challenging to establish the baseline for this program and that ERT meters would provide limited additional benefits in this regard.
Additional research	ConEdison is investing in pilot projects and evaluation studies to ground future analysis and projections.
Changing lead times for projects	ConEdison generally expects traditional pipeline commitments to be made at least three years prior to the need for the new capacity. Beyond this point, planning and engineering costs become considerable. Consequently, the ability of NPS to avoid the need for the pipeline capacity needs to be determined prior to this decision point.
Principle of universality & Cross subsidization	Due to the wealth of non-wire solution precedent in New York State, the PSC, intervenors and other stakeholders have become accustomed to the idea that discriminating on the basis of the location to achieve higher savings or curtailment is to the benefit of all if it allows all ratepayers to benefit from avoidance of large capital expenditures.
Changes in the Infrastructure Approval Process for Targeted DSM	There is a current PSC proceeding that will deal with long-term gas capacity planning that is expected to establish a formal process to incorporate NPS into the infrastructure approval process.
Appropriateness of cost-effectiveness testing	As part of the 2017 NPS solicitation, ConEdison filed an Interim Benefit-Cost Analysis handbook designed especially for NPS. The utility has issued an updated version of the document.[46] ConEdison is planning to publish a revised version before the end of 2020. Revisions will focus on the valuation of the avoidance or deferral of distribution system investments.
Overlap with broad-based DSM	The PSC and the New York State joint gas and electric utilities are accustomed to the use of "incentive kickers" (i.e. add-on to broad-based DSM incentive) for

[44] ConEdison, *Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures – Supply/Demand Analysis for Vulnerable Locations*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFCF94472-7929-4594-8CD0-C3903FDE6927%7D> [accessed 18 August 2020].
[45] Under certain definitions of AMI, an ERT meters are not properly "AMI" meter because they do not have two-way communication capability.
[46] ConEdison, *Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions (New York, NY, USA, 2018)*, 2018 <https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-pipes/benefit-cost-analysis-handbook.pdf>.

Challenge	
	non-wire solutions, and as such it is expected that a similar approach would be allowed on the gas side. However, it is unclear whether incentive kickers would be funded by dedicated, incremental NPS budgets or the gas utilities would draw on the enlarged DSM budget as a result of the Accelerated EE Order.
Utility remuneration and incentives to pursue geo-targeted DSM	For non-wire solutions, ConEdison is allowed to amortize non-conventional expenditures and earn its regulated return on equity. In addition, ConEdison is allowed to earn a performance incentive as a share of the social net benefit. For NPS, ConEdison asked for a similar treatment in 2017 but was refused the performance incentive for the first tranche of funding, $40.1m ($29.7m USD).

New York, National Grid

National Grid provides natural gas to 1.9 million customers in Brooklyn, Queens, Staten Island, and Long Island. The utility has seen sustained growth in demand throughout its service territory due to continued growth in population, commercial customers, new construction, and oil-to-gas conversions.

As of late 2020, National Grid's demand projections suggest that it has limited room for error since its current supply sources match its forecasted daily peak demand for a cold winter day. National Grid has already deployed LNG and CNG to supplement long-term pipeline capacity contracts: 13.5% of its peaking capacity for the coming winter comes from LNG, 12.5% will come from contracted peaking supplies, and 1.5% will be provided by CNG trucking. For winter 2020/21 and 2021/22, any additional load growth will primarily be met by adding CNG trucking capacity.[47]

National Grid announced a moratorium on new gas hookups in 2019 in both its Long Island and New York service territories, which has since been lifted until September 2021. The underlying imbalance between the load growth in its service territories and its natural gas supply is due to the delay and then cancellation of the proposed Northeast Supply Enhancement (NESE) pipeline project.

In February 2020, National Grid published a Long-Term Capacity Report,[48] followed in May 2020 with a Supplemental Report[49] to present a comprehensive analysis of its capacity constraints and all available options for meeting its long-term demand. The utility has recently committed increased funding to its gas DSM and DR efforts due to local regulations and broad-based EE targets as per the latest acceleration of EE in New York State, "New Efficiency: New York". However, National Grid has forecasted a supply shortage even when factoring in space and water heating electrification efforts, which are also being driven by New Efficiency: New York. Its electrification program will be focusing on conversions from heating oil in existing buildings, and it will also motivate new construction to favor air-source and ground-source heat pump rather than natural gas.

In addition, National Grid is pursuing additional RNG, with a new facility tied to a wastewater treatment plant nearing the end of construction/commissioning and expected to be operational

[47] National Grid, *Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")* (New York City, NY, USA, 2020) <https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Report_February_24_2020.pdf>.
[48] National Grid, *Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")*.
[49] National Grid, *Natural Gas Long-Term Capacity Supplemental Report for Brooklyn, Queens, Staten Island and Long Island* (New York City, NY, USA, 2020) <https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Supplemental_Report_May_8_2020.pdf>.

before the end of 2020. The utility is also working with The Institute of Gas Innovation and Technology (I-GIT) and New York State Energy Research and Development Authority (NYSERDA) to assess the impact of hydrogen on its gas infrastructure, determine the maximum blend, and identify upgrades that are necessary to inject hydrogen into its pipeline network.

Despite all the activities noted above, National Grid is forecasting a gap of 6.27-10.90m m^3 of natural gas per day (230 and 400 BBtu/day) to meet demand growth over the course of the next 10 years. As part of the two Long-Term Capacity reports, National Grid evaluated multiple options to address this gap, including additional LNG facilities (some off-shore or on barges), small-scale transmission loops, added compression on existing interstate pipelines, incremental EE or gas DR, and additional electrification. The utility also included the NESE pipeline as a point of comparison against all the aforementioned options.

The economic analysis approach of National Grid was based on the evaluation of a series of different scenarios. All scenarios were designed to meet the 10-year forecasted capacity shortfall according to two demand forecasts. The Northeast Supply Enhancement (NESE) pipeline project would suffice to avoid the shortage over 10 years' worth of demand growth under a high demand forecast. A 100% no-infrastructure scenario (only EE, gas DR and gas to electric (G2E)) is another scenario that was assessed by National Grid. All other scenarios were mixes of distributed infrastructure and no-infrastructure solutions.

National Grid's economic analysis provides a useful illustration of the infrastructure investment challenges faced by utilities in jurisdictions with ambitious decarbonization targets like New York State. Natural gas is currently preferred by many customers for space and water heating, and new pipeline capacity may be needed to meet expected demand growth, but gas demand may plateau and begin to decline before these new assets are fully depreciated due to the pressure of decarbonization policies.

The approach used by National Grid assumes that EE, gas DR and G2E can be deployed incrementally and almost on a just-in-time basis allowing the utility to throttle the amount of capacity and adapt quicker and more accurately to changes in the demand[50]. NESE was the least costly scenario in a "high demand growth future" (the upper bound of National Grid's demand forecast). However, NESE was also the costliest scenario under a low demand growth future (the lower bound) because the infrastructure would be underutilized while needing to be amortized in full. However, the "No-Infrastructure" scenario did not perform much better, even in a low-demand growth scenario. The least cost scenarios in the low demand future were mixes of distributed infrastructure solutions (CNG, LNG and smaller infrastructure upgrades), and no-infrastructure solutions (EE, gas DR and G2E). In other words, the distributed infrastructure solutions were cheaper options (per Btu/day) than most of the no-infrastructure options (albeit more expensive per Btu/day than NESE), and so adding them into the mix lowered the cost of the overall "blend". The capacity of distributed infrastructure acquired is also lower, leaving the costlier no-infrastructure options at the margin to close the gap (or not, if the low demand scenario does not materialize).

National Grid also performed the same economic analysis while layering on top a valuation of carbon emissions. The exercise did not materially change the conclusions. National Grid, as is the norm in New York State, used the *social cost of carbon* to attribute a value to carbon. The social cost of carbon is a valuation of the cost of externalities that are expected from carbon emission in the long run. In New York State, the accepted practice is to use the US

[50] To be fair, EE, gas DR and G2E also have lead time as well as forecasting and performance uncertainties. So, the assumption that EE, gas DR and G2E can be throttled and reach target with accuracy is debatable.

Environmental Protection Agency's social cost of carbon from 2017[51] (an analysis performed under the Obama Administration) to value the cost impact of carbon. National Grid used the values corresponding to a 3% discount rate, or $42 (2017 $USD) in 2020.

National Grid did not exclusively focus on the financials and value of carbon emissions of the scenarios. They also performed a qualitative analysis that included risks, permitting, lead time, challenges with citing the distributed infrastructure, and other, hard-to-quantify costs and benefits.

In recent years, National Grid has been exploring C&I gas DR programs to manage system peak demand and sustain system pressure. It started with a pilot in 2017 with the goal of alleviating peak hour demand on its distribution system. A total of 16 facilities have contributed 6,691 m^3/hr (241 Dth/hr) of demand reduction. In the fall of 2019, the DR portfolio was expanded to add a program that addressed constraints at the city gates (i.e. alleviating the peak day load rather than the peak hourly load). Customers participating in the DR program must produce a verifiable reduction during the event hours that reduces their gas consumption over the entire peak day, with many choosing to switch to a different fuel during the event hours. Currently, there is no restriction on the type of backup fuel used, and so customers tend to prefer conventional delivered fossil fuels. National Grid is considering various program structures to encourage the use of biodiesel or other renewable options.

In addition to the DR program for firm customers described above, National Grid has two non-firm rates as well, which are called "non-firm DR" in recognition of the reduction they provide during event hours. The non-firm DR rates are the former interruptible and temperature-controlled rates that were offered by National Grid. The non-firm DR program has two tiers: Tier 1 is a fully automatic switchover equipment at -8.9°C (16°F), and Tier 2 can have an automatic, semi-automatic, or manual switchover equipment at -6.7°C (20°F). National Grid installs a KYZ-pulse reader on the facility gas meter of participants to measure impacts, and an automatic, remote switching device as applicable.[52]

The firm C&I gas DR program achieved 245,000 m^3/day (9 BBtu/day) of reduction in 2019/2020 but is not at scale yet. It is expected to reach 454,000-1,440,000 m^3/day (20-53 BBtu/day) of capacity by 2034/35.

Finally, National Grid is considering a residential and small business bring-your-own-thermostat gas DR pilot program, and a small and medium business behavioural program. The utility is also seeking approval to deploy advanced gas metering infrastructure in its service territory, with a proposal to deploy 640,000 AMI gas meters over a four-year installation period starting in 2022.[53] In advance of the gas AMI meter deployment, National Grid is considering recruiting participants in catchment areas downstream of pressure meters. They could then use the pressure meters to infer the flow impacts.

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[51] U.S. Environmental Protection Agency (USEPA), 'The Social Cost of Carbon - Estimating the Benefits of Reducing Greenhouse Gas Emissions', 2017 <https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html> [accessed 24 July 2020].

[52] National Grid, *Case 19-G-0309 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service and KeySpan Gas East Corp. d/b/a National Grid for Gas Service*, 2019 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BE11E743B-6CAF-4905-AA13-4807CE7A56B4%7D>.

[53] National Grid, *Case 17-E-0238 & Case 17-G-0239 Report of Niagara Mohawk Power Corporation d/b/a National Grid on the Proposed Implementation of Advanced Metering Infrastructure*, 2018, p. 14 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5A9009BC-356F-4B0F-B3C7-F255EA8AA5A8%7D>.

Exhibit 5 summarizes National Grid's perspectives on the NPS challenges noted in Enbridge's 2018 IRP Study.

Exhibit 6 Perspective on NPS Challenges from National Grid of New York and Long Island

Challenge	
Reliability	There is a degree of comfort with the C&I gas DR program because of the experience with temperature-controlled customers and interruptible customers. National Grid's pilots are also providing insights into typical impacts per participant, potential participation rates, and the persistence of the savings.
Lack of metered data	National Grid uses a device that reads pulses from their C&I customer meter to verify impact from the C&I gas DR program. The utility is also accounting for the lack of AMI gas metering in the experimental design of its future pilots. For example, National Grid is considering designing its pilot to recruit participants in a small catchment area where a pressure meter can be used to estimate flow.
Additional research	National Grid is completing additional research through its two pilots.
Changing lead times for projects	The NESE project that was abandoned would have taken 2 years due the advanced stage of design it had reached. Most large-scale infrastructure and distributed infrastructure project would require 5 to 6 years before the first delivery.[54] In addition, National Grid recognizes that gas DR is not yet a mature program. It is a solution expected to ramp and reach its potential toward the end of the 2020-2035 planning horizon contemplated in its long-term capacity planning.
Principle of universality, Cross subsidization	There is a high degree of awareness in the public of the capacity shortage due to the gas hookup moratorium. For this reason, National Grid anticipates relatively mild challenges related to universality and cross-subsidization.
Changes in the Infrastructure Approval Process for Targeted DSM	For now, National Grid's constraint is at the city gates. Consequently, they have not considered geo-targeted programs. The utility is planning on offering EE programs and gas DR to all their customers.
Appropriateness of cost-effectiveness testing	National Grid is in the process of developing a BCA framework for use with these types of programs and expects to file it later this fall. To our knowledge, only ConEdison has a BCA Handbook for BCA in New York State.
Overlap with broad-based DSM	Gas DR is incremental to broad-based DSM funding and targets.
Utility remuneration and incentives to pursue geo-targeted DSM	It is to be expected that National Grid will be able to obtain the same utility remuneration and incentive mechanism as ConEdison. See Exhibit 5.

New York, Central Hudson

Central Hudson is a gas and electric utility that delivers gas to approximately 84,000 customers in New York State's Mid-Hudson River Valley. The utility has attempted to use beneficial electrification to avoid costly replacement of leak-prone pipes on its distribution system. They refer to the approach as a "transportation mode alternative". The initiative consists of offering technical assistance and incentives to convince customers to cut off their gas connection and fully electrify their space heating via ground-source heat pumps or air-source heat pumps. The

[54] National Grid, *Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY")*.

initiative targets pipes that are scheduled for replacement due to obsolescence, particularly when the pipes connect to only a handful of customers.

To be successful in avoiding the replacement of a pipe, Central Hudson needs to be able to convince all the customers connecting to a particular pipe to switch off of natural gas. However, this has been challenging since in New York State the utilities have an obligation to provide gas service and customers have the right to retain their gas services.

In a 2018 Order from the PSC establishing electric and gas rate plans, the PSC required Central Hudson to submit an implementation plan to identify NPS.[55] Central Hudson explored the opportunity of offering geo-targeted EE programs to high constraint areas of its distribution system due to intra-day drops in pressure on certain laterals of its system.

Central Hudson commissioned a study on the avoided cost of its distribution system.[56] The study was based on a novel approach based on probabilistic (as opposed to deterministic) load forecasting. The focus of the analysis was to value the avoidable distribution cost due to peak-coincident load growth. The analysis estimated location-specific patterns for individual gas systems (i.e. subsections of the gas distribution network). Because increases and decreases in load compound over time, the trajectory of the load can deviate substantially from a simpler deterministic load growth model. The analysis generated indexes measuring the likelihood of pressure drops – due to spike in intra-day coincident demand -- that would trigger the requirement for an upgrade.

Based on this study, Central Hudson identified three systems with a likelihood of triggering an upgrade over a 10-year time horizon. For one of the systems, the replacement was needed so quickly (within the next two years) that an NPS could not be deployed. For the second system, Central Hudson was able to implement a relatively low-cost supply side upgrade to address the pressure issue. The third system (the Vassar Road (PN) System) was identified as highly relevant for an NPS project since analysis suggested that there was a 20% chance that an upgrade would be required in the next 10 years.

Central Hudson conducted a simplified benefit-cost analysis to compare the incremental costs of higher incentives (“incentive kickers”) and the benefits associated with targeted load reductions in the PN line, evaluating six geo-targeted EE and electrification measures currently offered under their DSM portfolios. The future of the PN line is not certain enough to determine the need of an NPS at this time, but Central Hudson has considered the opportunity to evaluate the potential impacts of leveraging existing DSM programs to manage potential future load constraint.

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[55] NY Public Service Commission, *CASE 17-E-0459 and CASE 17-G-0460 ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLAN*, 2018.
[56] Demand-Side Analytics, *2020 Central Hudson Location-Specific Avoided Gas Distribution Costs Using Probabilistic Forecasting and Planning Methods*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA193B651-0944-48CC-86C5-945C70634191%7D>.

Exhibit 7 summarizes the results for the locational benefits of the measures, indicating smart thermostats as the most cost-effective measure. However, it is unclear whether the benefit-cost ratio was computed based on the full New York benefit-cost analysis framework.

Exhibit 7 Simplified Benefit Cost Analysis of Kickers on Top of Broad-Based DSM Incentive for Central Hudson[57]

Measure	Locational Benefits	Locational Costs	Locational Net Benefits	Locational BC ratio	Avoided pipline capacity (CCFh-yr)
Smart thermostat	$ 371,344	$ 313,817	$ 57,527	1.18	74
Heat Pump Water Heater	$ 351,958	$ 1,589,387	$ (1,237,429)	0.22	75
ASHP - All-Electric Whole Home	$ 361,190	$ 1,067,952	$ (706,761)	0.34	60
ASHP - Dual-Fuel	$ 83,869	$ 270,449	$ (186,581)	0.31	14
Efficient Combi Boiler	$ 452,707	$ 2,323,269	$ (1,870,562)	0.19	73
Efficient Furnace	$ 539,779	$ 603,607	$ (63,828)	0.89	75

As a result of this analysis, Central Hudson is planning to implement an incentive kicker to promote higher adoption rates of advanced thermostats for customers served by the PN line in advance of the 2020/2021 heating season. The incentive kicker being considered would be substantially higher than the broad-based incentive (anywhere from 2 times to 4 times the regular incentive). Given the flexibility of the New York DSM framework, there is no need to request authorization.

In addition, Central Hudson is developing a request for proposal to solicit technology and fuel neutral market responses for system level peak reductions and reduced wholesale gas costs. The RFP is scheduled to be released in the 3rd Quarter of 2020. The RFP responses will be evaluated using the benefit-cost analysis framework.[58] A full discussion of the benefit-cost framework in New York State is presented in Section 5.

Exhibit 8 presents the 2020 perspectives of Central Hudson on the challenges to NPS that were uncovered as part of the 2018 IRP.

Exhibit 8 Perspective on NPS Challenges from Central Hudson Gas

Challenge	
Reliability	The purpose of the advanced thermostat pilot is to ascertain the reliability of the NPS solution. The Demand-Side Analytics study explored the reliability of load forecast with low degree of diversity on branches of the distribution systems.
Lack of metered data	Central Hudson did not express concern over lack of metered data.
Additional research	The pilot is expected to launch in Q4 of 2020 or Q1 of 2021 and so data is not yet available.
Changing lead times for projects	Central Hudson does not have an official position on this issue. However, the utility made the decision to implement a traditional pipe upgrade for a system that had a high likeliness of pressure drops in the next two years.
Principle of universality and Cross subsidization	Central Hudson did not express any concern over the principle of universality and cross-subsidization.

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[57] Central Hudson Gas & Electric Corporation, *Cases 17-G-0459, et Al. Assessment of Natural Gas Demand-Side Load Management Solutions*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B1CB068E6-2DE6-490E-B5F1-1816192281F9%7D>.

[58] Central Hudson Gas & Electric Corporation.

Challenge	
Changes in the Infrastructure Approval Process for Targeted DSM	Central Hudson reported the new gas planning order from the PSC,[59] which instructed all gas utilities in the State to issue a series of supply and demand analysis reports. PSC staff will use the responses from the utilities to modernize the gas system planning process so that NPS can more easily be deployed. This is hoped to help avoid moratoria on new gas hookups and reduce the need for future infrastructure investments.
Appropriateness of cost-effectiveness testing	Central Hudson used a straight comparison between the avoided cost of the distribution system upgrade with the cost of geo-targeted DSM as its benefit cost analysis to evaluate EE and electrification solutions to alleviate an area of high constraint. As part of the upcoming solicitation, Central Hudson plans on using the full-fledge benefit-cost analysis framework used in New York State.
Overlap with broad-based DSM	"Incentive kickers" are an accepted strategy in New York State for both non-wire solutions and NPS. Utilities add incremental incentives onto existing incentives from broad-based DSM programs.
Utility remuneration and incentives to pursue geo-targeted DSM	It is to be expected that Central Hudson will be able to obtain the same utility remuneration and incentive mechanism as ConEdison. See Exhibit 5.

New England

Considering that natural gas market conditions and other energy market conditions in New England States (i.e. Maine, Vermont, New Hampshire, Massachusetts, Rhode Island, and Connecticut) are similar to New York, as well as the prevalence of natural gas DSM programs in the region and the well documented lack of pipeline capacity into the region, ICF reviewed the information on NPS activities in the region, and reached out to several utilities in the region to discuss their experience with NPS.

The region does have extensive experience with distributed sources of natural gas supply, including distributed CNG and LNG, both to provide natural gas to large consumers without access to the natural gas grid, and to provide additional natural gas capacity in locations experiencing capacity constraints. However, ICF was able to identify only limited interest in NPS in the region, and no active NPS programs other than the existing broad-based DSM programs, and these distributed supply options.

ICF reached out to several gas utilities in the New England region, but was only able to consult with one. ICF spoke with Columbia Gas of Massachusetts to discuss the utility's experience with NPS. Columbia Gas staff indicated that the utility does not pursue any NPS or geo-targeted EE or DR, despite supply constraints that have led to moratoria in adding new gas customers in Northampton and Easthampton. Columbia Gas also indicated that they view NPS as cost-prohibitive, and that the impacts of geo-targeted EE or DR would be insufficient to avoid new pipes in the areas of high constraints on its distribution system.

Although ICF's research suggests that there is limited progress with regards to NPS in the New England States, it noted that Eversource is seeking approval for cost recovery for three GeoMicroDistrict pilots in the greater Boston area. This concept employs "networked geothermal boreholes, connected by a shared loop in the current gas right-of-way that provides

[59] NY Public Service Commission, *CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*.

thermal energy to customer buildings"[60] and could represent an electrification approach for current gas customers, while preserving the need for existing gas distribution pipeline infrastructure.

[60] Green Tech Media, 'Massachusetts Pilot Project Offers Gas Utilities a Possible Path to Survival', 2020 <https://www.greentechmedia.com/articles/read/can-gas-companies-evolve-to-protect-the-climate-and-save-their-workers> [accessed 3 September 2020].

4. NPS in New York State

In this section of the report, ICF reviews the differences and similarities between New York State and Ontario that influence the development and value of NPS options in the two jurisdictions. The comparison addresses differences and similarities with respect to natural gas markets, legislative mandates, regulatory regimes, and rule-making structures in New York State and Ontario that have influenced the need and viability of NPS in the two jurisdictions.

New York State is of particular interest as the majority of NPS activity in the past three years has been in this jurisdiction.

4.1 Drivers for Non-Pipe Solutions in New York State

New York State (particularly Downstate New York) has seen a broad range of proposed NPS projects, including distributed CNG, and LNG projects, as well as local RNG projects. In addition, a few innovative NPS pilot projects based on EE, gas DR, and electrification programs have been implemented or proposed. More pilot programs and projects are underway. NPS are expected to become part of the routine long-term capacity planning process for the utilities, and the State has been active in developing a set of best practices surrounding NPS.

There are several drivers that have led to the recent NPS activity in New York State:

- **Strong Load Growth:** There has been a long-term growth trend in natural gas demand, including both customer growth and demand (consumption) growth in certain areas of the State. This growth has been driven by conversions from heating oil to gas, as well as new construction, primarily in the Downstate regions of the State. The pipeline capacity constraints have been exacerbated by changes in natural gas supply markets serving the State and surrounding markets, and growth in demand in surrounding markets, including New Jersey and New England. The result has been that several areas of the State have become supply constrained.
- **Constraints on the Development of Long Term Infrastructure:** The cancellation of several of the recent natural gas pipeline projects designed to bring new pipeline capacity into Downstate New York, including the NESE and Constitution Pipelines, is causing a perception that new interstate pipeline projects will become increasingly challenging to develop. The NESE pipeline project would have provided a new interstate pipeline adding not only more capacity into the Downstate region, but also a new access to different suppliers. After first applying for state permits in June 2017, NESE was repeatedly denied its Section 401 Water Quality Certification by the New York State Department of Environmental Conservation until, Williams, the project developer, decided to cancel the project due to the regulatory hurdle. The Section 401 Water Quality Certification is outside of the jurisdiction of the Public Services Commission (PSC), the energy regulator in New York State.
- **High Cost of Infrastructure Development:** The immediate solutions employed by ConEdison and National Grid of New York and Long Island in Downstate New York include short-term peaking contracts, additional LNG, CNG injection sites, and perhaps more modest interstate pipeline upgrade projects. Incremental EE, gas DR, and electrification are being considered as medium to long-term options, as several solutions are currently being pilot tested. Delivered CNG would be deemed too costly or risky in many other jurisdictions, but not in New York. Although sales are comparable, natural gas residential retail rates in Downstate New York are twice as high as Toronto, and C&I retail rates are also 40% higher in compared to Toronto (See Exhibit 11. Like Toronto, Downstate New York has a high population and is densely urbanized. This makes finding running lines for new pipelines difficult and construction on urbanized roadways with many utility conflicts and traffic issues is also very challenging.

- **Public Concerns and Focus due to the Proliferation of Moratoria and the NESE Project Consultations:** The moratoria that were promulgated by many gas local distribution companies in New York and the high profile public consultations that led to the rejection of the Section 401 Water Quality Certification by the New York State Department of Environmental Conservation have created a difficult policy landscape that the gas utilities have had to navigate. These circumstances have resulted in the utilities launching innovative pilots and projects in order to demonstrate best efforts to solve the capacity constraints.
- **Alignment with State Government Policies:** The NPS are in alignment with the clear, formal state policies – namely the Reforming the Energy Vision, Climate Leadership and Community Protection Act and New Efficiency New York (and the corresponding Accelerated Energy Efficiency Order). The New York State Energy Research and Development Authority (NYSERDA) and the Joint Utilities of New York are also two organizations that have undertaken critical analytical and research work that have contributed to achieving success for NWS and could be utilized to accelerate the development of NPS.

  What is unclear in New York State, however, is whether additional funding will be drawn from ratepayers to fund additional EE, gas DR, and electrification. For instance, in its Long-Term Capacity Planning Report, National Grid indicated that a critical shortage was forecasted over the course of the next 15 years despite the Climate Leadership and Community Protection Act and the ambitious EE and electrification targets from New Efficiency New York (and Accelerated Energy Efficiency Order).
- **Precedent with the REV and NWS in the Electricity Sector:** The State of New York is considered by many as one of the two states, along with California, that is leading the way in removing barriers to the cost-efficient adoption of DER. The effort was launched by the REV initiative, which led to a regulatory environment that is favorable to NWS. Early, high-profile NWS projects such as the Brooklyn-Queen Demand-side Management project (see page 59) led to NWS being considered systematically as part of electricity distribution system planning. NWS are being considered more routinely, with established standard practices including but not limited to a Benefit-Cost Analysis (BCA) Framework. Electric utilities in New York State are rewarded for NWS through a performance incentive, where the benefits are split 50/50 between the utility and ratepayers – which not only makes up for foregone earnings due to avoided or deferred capital expenditures but actually makes NWS a new profit center for the investor-owned utilities.

  The PSC is seeking to follow a similar path for NPS. Cross-pollination is also helped by the fact that many gas utilities in New York are joint gas and electric utilities. For instance, ConEdison's BCA Handbook for NPS was inspired from ConEdison's own BCA Handbook for NWS.

  The NPS pilot projects that have been undertaken have been less effective than the major NWS projects. Furthermore, to date, the PSC has created neither a benefit-sharing scheme for gas utilities, nor a dedicated budget for NPS. In fact, in December 2017, ConEdison was asked by the PSC to use its existing broad-based DSM budget to pursue geo-targeted EE, gas DR, and electrification pilots.

  For NWS, ConEdison is allowed to amortize the expenses over 10 years based on its weighted average cost of capital, thereby its regulated return on equity. In addition to recovering the amortized costs, ConEdison is allowed to collect an earning adjustment mechanism worth 30% of the net benefit based on the societal cost test (SCT).

  In 2017, ConEdison had proposed a cost recovery scheme and a performance incentive for NPS mirroring that of NWS, but this proposal was refused by the PSC, thereby limiting

ConEdison's remuneration to cost recovery for the first tranche of funding, $40.1m ($29.7m USD).

Ontario is not far behind in terms of DER policies due to efforts by the OEB who is working on public consultation on DER, an early NWS project at Cecil TS by Toronto Hydro, and the thought leadership effort by the IESO, as well as the York Region pilot project by Alectra Utilities and the IESO. However, the assessment of NWS has not been turned into a routine process in front of the OEB as it has been in New York in front of the PSC.

In short, the significant supply shortage situation, coupled with the experience with NWS on the electric side, have led New York State gas distribution companies to consider NPS to alleviate constraints at the city gates (i.e. calling for intensifying EE, gas DR, and electrification over their entire service territories). In certain cases, like with Central Hudson and ConEdison, these circumstances have also led to efforts to alleviate distribution pipe constraints through geo-targeted EE, gas DR, and electrification.

4.2 Gas Market Structure

This section of the report provides an overview of the natural gas market structure in New York State to gain a better appreciation of how it led to and is sustaining the NPS effort in the State, and provides a comparison of the market structures in Ontario and New York State.

New York State has 11 major gas utilities that are supplied with natural gas from 11 interstate gas pipelines. In New York State, there are more than 4,550 miles (7,320 km) of natural gas transmission lines, 48,680 miles (78,340 km) of distribution mains, and 3,210,800 natural gas service lines to almost 5 million customers. New York State has (mostly) joint gas and electric utilities.[61] They are regulated by the New York State PSC.

The overall throughput of the New York State gas market is similar to the market throughput in Ontario. The 11 major natural gas distribution utilities in New York State delivered 25.3b m^3 (928 TBtu) of natural gas to their customers in 2018. Ontario now has four gas utilities regulated by the Ontario Energy Board (OEB). The merger of Enbridge Gas and Union Gas on January 1, 2019 consolidated the province's two dominant distribution companies. There are over 3.7 million natural gas customers in Ontario. In 2018, natural gas sales reached 26.1b m^3.[62,63]

Pipelines and Storage Capacity

A discussion about interstate pipelines is relevant for two reasons. Firstly, it is important because recent challenges with interstate pipeline network expansion is causing expected shortages in peaking capacity in numerous areas in New York State, which in turn have been a critical driver for recent NPS pilots in Downstate New York and a driver for the current proceeding of the PSC on updating the approach to long-term gas capacity planning. Secondly, an understanding of how gas is transmitted and then distributed in the State is critical to

[61] Key exceptions include National Grid of New York and Long Island, which is gas only, and Long-Island Power Authority, an electricity-only utility. National Grid of New York distributes gas on a significant part of the electric service territory of ConEdison. National Grid of Long Island distributed gas on the service territory of Long-Island Power Authority.
[62] Ontario Energy Board, *Yearbook of Natural Gas Distributors - 2018*, 2019 <https://www.oeb.ca/oeb/_Documents/RRR/2018_Yearbook_of_Natural_Gas_Distributors.pdf> [accessed 30 July 2020].
[63] There are five small gas companies, as well as two municipally owned gas companies (City of Kitchener and City of Kingston), that are not rate regulated by the OEB.

understanding the key differences that need to be made in transferring NWS and electricity sector concepts to NPS and the natural gas sector.

New York State is served by 11 interstate pipelines, allowing the utilities and other consumers to source their gas from across North America. Over the past five years, the share of gas supply from the US Gulf Coast and Midcontinent has decreased as increasing production from the nearby Marcellus and Utica basins has increased its market share. Gas sourced from Western Canada and gas storage in Dawn, Ontario remains an important source of the winter supply mix for New York State utilities. Most of the utilities in the state purchase most of their winter firm gas supply from the Marcellus/Utica region and the rest of the gas supply is from the Gulf Coast, Canadian, and local supply regions.

Except for of the National Fuel Gas Supply pipeline, all the interstate pipelines are fully contracted for their delivery capacity into the State. Almost all the natural gas consumed in the state is delivered to utility city gates using interstate pipeline capacity contracted directly from the interstate pipelines or purchased at the city gate from other parties holding pipeline capacity on the interstate pipeline system.

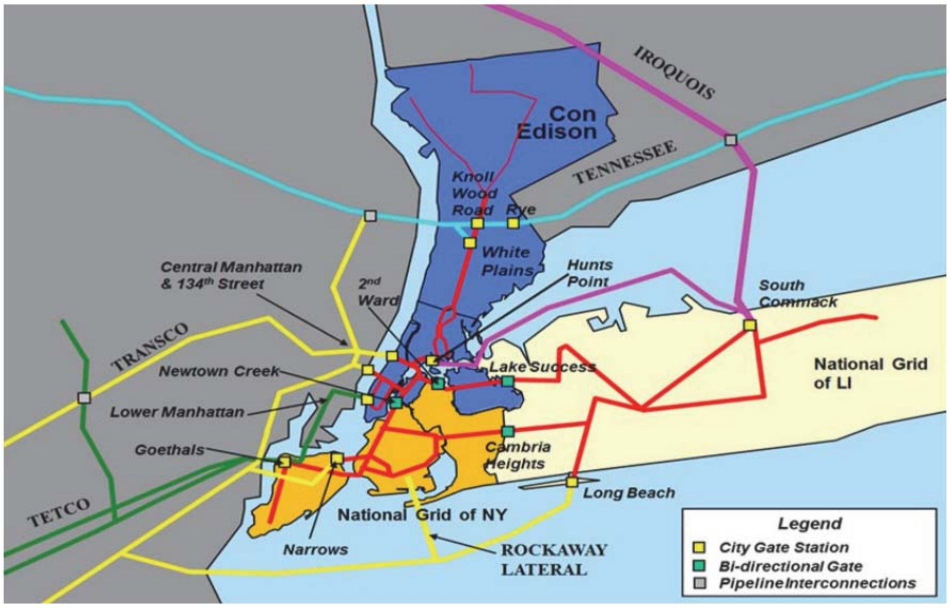
Not all of the interstate pipeline capacity to New York State is held by the utilities and natural gas generator. A percentage of it is held by marketers. For this reason, New York State gas utilities have access to gas peaking contracts from these marketers. However, because the Federal Energy Regulatory Commission (FERC) allows market-based pricing only for contracts of less than one year in duration, gas purchased from marketers in constrained regions, can be sold above market rates and is often only offered on a short-term basis. This means that it has to be renegotiated often, costs can vary widely, and there is limited assurance that the capacity will be available in the future, thereby exposing utilities to a high degree of price and availability risk.

In the US, interstate pipelines are regulated by FERC and new interstate pipeline construction require FERC approval. Pipeline transportation rates are approved by FERC using cost-of-service ratemaking. Additionally, the FERC sets rates for intrastate pipelines under Section 311 of the Natural Gas Policy Act of 1978. Intrastate rates are computed using the same cost-of-service methodology used under the Natural Gas Act. But just like for transmission lines built by utilities that are regulated by the PSC, if demand does not materialize on a FERC-regulated pipeline, the remaining transportation customers on the pipeline may be at risk of having to pay increased rates to cover the cost-of-service on the pipeline.

The interstate pipeline supply is most constrained in the downstate area, which is served by Keyspan Gas East Company (National Grid of Long Island), Brooklyn Union Gas Company (National Grid of New York), and the Consolidated Edison Company of New York (or just “ConEdison”). A significant amount of the three Downstate utilities’ gas supply, over 27% of it, is provided by winter peaking contracts, delivered service contracts, LNG storage, CNG, RNG, and local production.

Exhibit 9 shows the service territory of ConEdison and National Grid. ConEdison has several constrained areas due to upstream supply shortage, and so does National Grid service territories.

Exhibit 9 Downstate New York Transmission Network



Source: National Grid

Exhibit 9 shows the interconnection points at the edge of the distribution service territory – the city gates – where interstate and intrastate transmission pipeline connect to the distribution system.

The State has 26 active underground storage facilities with working gas capacity. There are three LNG peak shaving facilities in the State and all of them are in the Downstate area; they are owned by ConEdison and National Grid. The State's three LNG peaking facilities were built in the late 60s to early 70s and are at risk of both planned outages for maintenance and unplanned outages due to age.

Both ConEdison and National Grid expect to expand their CNG assets to meet growing demands in the region. However, the utilities have concerns about the scalability of CNG, given the difficulties of moving many trucks in the metropolitan New York City area on congested roadways and the limited providers of CNG in the region. In the Upstate region, National Grid Niagara Mohawk and NYSEG are the only two utilities that utilize CNG to meet peak day demands.

In New York State, the planning of the gas transmission network is a process that is generally less public than that for the electricity transmission sector by design and for historical reasons than related planning on the electricity. Gas utilities tend to negotiate with pipeline operators and developers for supply capacity with a higher degree of confidentiality than electric utilities. This is partly for historical reasons – the gas interstate networks were less frequently part of vertically-integrated utilities – and because of the nature of the commodity being delivered (i.e. its "storability").

Ontario Gas Supply Infrastructure

To meet Ontario's requirements, natural gas is brought in on eight interprovincial gas pipelines. Historically, Ontario's natural gas demand has been met by supplies from Western Canada. Imports into Ontario began to increase after 2000 when a route was opened for natural gas from

Western Canada to reach the US Midwest, where it could then be re-imported into Southern Ontario through other pipelines.

This supply dynamic was further shifted in the last decade by the development of significant shale gas resources in the US Northeast, and the construction of additional pipeline capacity allowing Ontario to access these lower cost gas resources. As a result, imports to Ontario from the US have continued to grow, and the province now receives less gas from Western Canada. Several pipelines that historically exported natural gas from Ontario into the United States have been converted to import natural gas, or have the ability to both import or export at different times of the year.

The large Dawn natural gas storage and trading hub in Southern Ontario has gained increasing importance as these supply dynamics shift, given its size, pipeline connectivity, and access to different supply basins. This dynamic has given the Dawn market access to numerous, reliable, and low-cost sources of gas, which has been reflected in the recent price differences between Ontario and New York State.

Distribution System

In New York State, the gas distribution companies own and operate the pipeline networks within their service territories. Compared to the US national average, New York State's natural gas distribution pipeline network is relatively old. The older pipes tend to be leak-prone and pose significant risks to the system. The utilities have had to increase their capital spending significantly over the last few years to replace old cast iron pipes. As the distribution systems of the three Downstate New York utilities are older than their Upstate peers, the need to invest in system reliability is more urgent for these utilities. Moreover, given the geographic differences, the unit cost of construction is significantly higher in the Downstate region. Downstate New York has a high population and is densely urbanized. This makes finding running lines for new pipelines difficult and construction on urbanized roadways with many utility conflicts and traffic issues is also very challenging. As a result, the capital expenditure of the three Downstate utilities is much higher than the Upstate utilities.

Regulatory Regime

In New York State, natural gas utilities are regulated by the PSC. The PSC is a part of the New York State Department of Public Service and is supported by the Staff of the New York State Department of Public Service. The PSC has a broad mandate to ensure access to safe, reliable utility service at just and reasonable rates. The PSC:

- Exercises jurisdiction over the siting of major gas and electric transmission facilities and has responsibility for ensuring the safety of natural gas and liquid petroleum pipelines.
- Is responsible for developing and enforcing safety standards for natural gas, hazardous liquid, and steam distribution pipelines located within the State.
- Approves the siting of major intrastate pipelines in New York State through an Article VII proceeding. (For interstate pipelines, the siting and routing approval process is conducted under the FERC's jurisdiction.)
- Reviews the annual capital expenditure of natural gas utilities and may order improvement in the manufacture, conveying, transportation, distribution, or supply of gas.
- Reviews rate applications, with rates set based on a cost-of-service approach. Gas utilities in New York State get access to shareholder performance incentive added to cost of service named "earnings adjustment mechanism". Utilities propose earnings adjustment mechanism to the PSC based on their specific goals and the circumstances of their service territories, and they are adjudicated independently.

In Ontario, the natural gas utilities are regulated by the OEB. While the OEB regulates the province's natural gas distribution companies (Enbridge Gas Inc. and EPCOR Natural Gas, City of Kitchener and Kingston), they are not licensed by the OEB, but instead have franchise agreements with municipalities across the province. A franchise agreement, which must be approved by the OEB, allows the local gas distribution company to provide service.

The OEB:

- Has regulatory responsibility for intra-province pipelines that are entirely based in Ontario.
- Reviews the annual capital expenditure of natural gas utilities.
- Decides on regulated distribution company's rate applications, also based on a cost of service approach. Gas utilities in Ontario get access to shareholder performance incentive, earnings adjustment mechanisms, added to cost of service. For instance, they get a performance incentive to achieve broad-based DSM targets.

Inter-provincial and pipelines connecting to US based transmission pipelines located in the province for natural gas (e.g. the TC Energy Canadian Mainline) are regulated by the Canada Energy Regulator (formerly the National Energy Board).

When considering whether to approve an intra-province gas pipeline, the OEB looks at a number of things, including whether: the project is needed and economically feasible; safety obligations set out by the Technical Standards Safety Act will be met; any environmental impact of the project have been identified and a plan to minimize those impacts has been developed; landowners affected by the project will be offered an agreement that is fair and reasonable; and any Indigenous Communities potentially affected by the project have been adequately consulted.[64]

Both the OEB and the PSC have a say on the siting of new transmission pipelines siting to city gates, with their national counterpart (CER and FERC respectively) having a say in interprovincial/interstate pipelines. In both Ontario and New York State, pipeline developers also must obtain many other permits depending on the pipeline route.

In Ontario, they may have to obtain a permit from Department of Fisheries & Oceans, a federal agency, a road crossing permit from the Ministry of Transportation of Ontario, rail crossing permits from individual railway companies, as well as numerous permit from municipalities to cross roads or causing traffic disturbance. In New York State, other permits required for a new transmission pipeline may entail permits from the Environmental Protection Agency, and the New York State Department of Environmental Conservation, as well as municipal agencies such as New York City Department of Environmental Protection, and the New York City Department of Transportation.

Permitting mechanisms outside of the OEB's own processes in Ontario, while rigorous, have been effective and can give way to new pipelines, so long as all rules are met, and impacts properly mitigated or compensated.

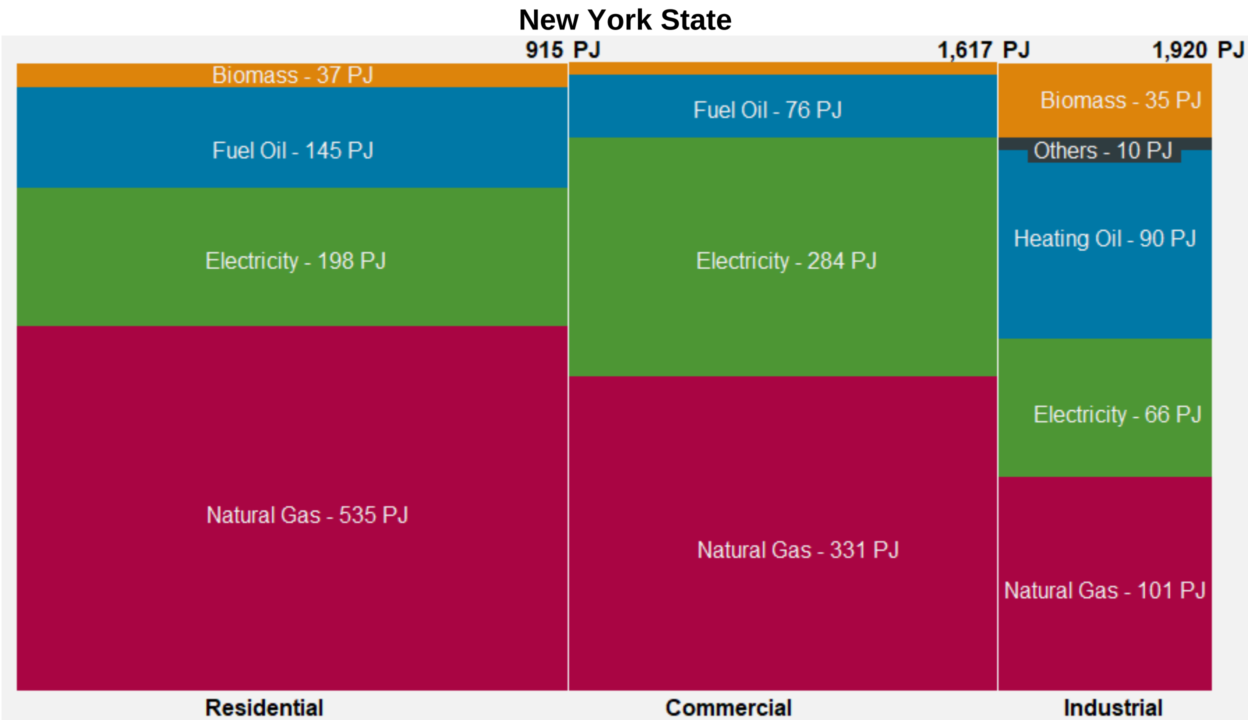
In New York State, as we will see in the next pages, the New York State Department of Environmental Conservation has repeatedly denied a permit to a high profile transmission pipeline project meant to supply Downstate New York, the Northeast Supply Enhancement (NESE), which led to both the abandonment of the project and the perception in the gas industry that the State would deny permit to most pipeline projects.

[64] Ontario Energy Board, 'We Review Utilities' Rates and Activities, and Make Decisions', 2020 <https://www.oeb.ca/about-us/what-we-do/we-review-utilities-rates-and-activities-and-make-decisions> [accessed 31 July 2020].

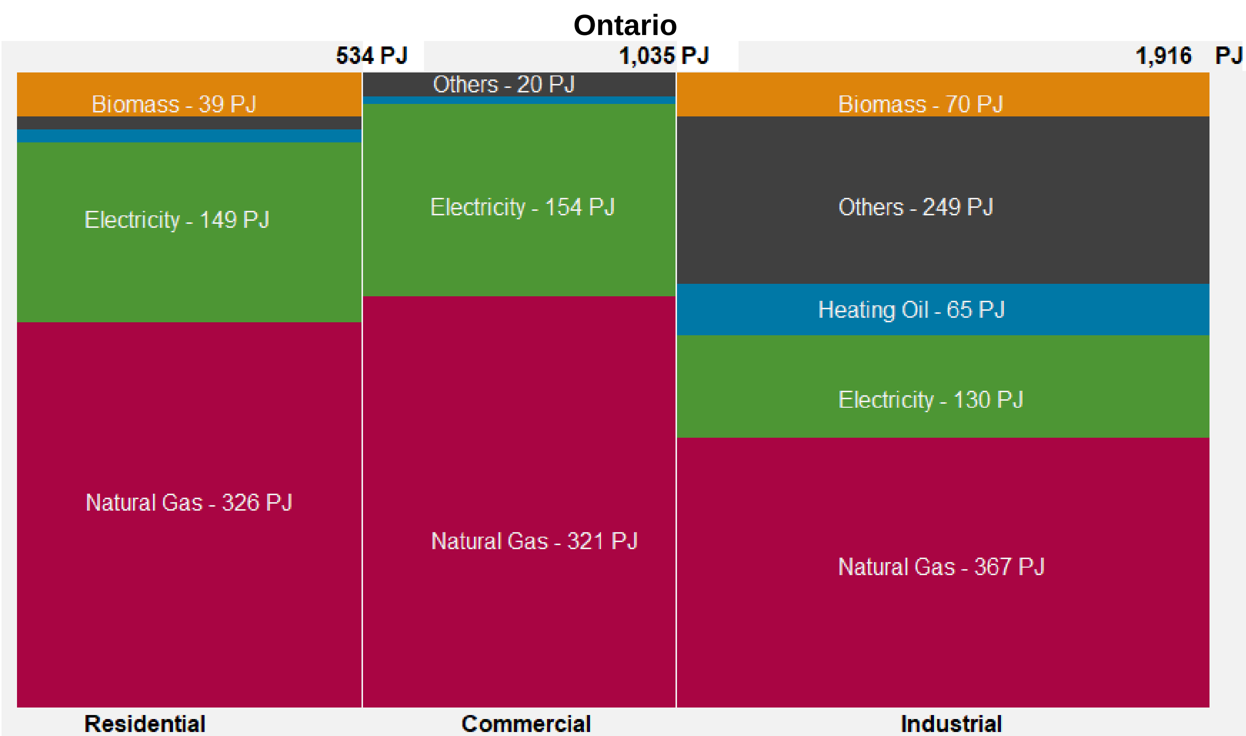
Space, Water and Process Heating

Exhibit 10 below illustrates the key differences in building energy end-uses between New York State and Ontario.

Exhibit 10 Energy End-Use of Buildings in New York State and Ontario (2018)



Note: "Others" includes Propane and Coal. Sources: EAI[65,66]



Note: "Others" includes Propane and Coal. Sources: NRCan,[67] OEB[68,69]

As shown in Exhibit 10, the overall energy used in the buildings sector in New York State in 2018 was similar to the overall energy used in buildings in Ontario, at about 2,000 petajoules (PJ) per year. The total consumption of natural gas use was also similar, at about 1,000 PJ. However, the distribution of the natural gas consumption in each jurisdiction differs widely by sector. New York State's total residential sector energy and natural gas demand are much more than its commercial and industrial sector demand, while in Ontario, the industrial sector uses much more energy and more natural gas than either the residential or commercial sectors.

Load growth from the industrial sector is typically more sporadic compared to the smaller but consistent year-over-year growth due to economic and demographic drivers.

Exhibit 10 also shows the importance of fuel oil used for space and water heating in New York State. After years of efforts to convert facilities to natural gas, there are still a considerable number of homes and commercial and industrial facilities that employ fuel oil. The conversion has historically contributed to the strong load growth in New York State and it continues to do so. Furthermore, the conversion from fuel oil to gas has contributed to reducing the carbon intensity of space heating in the State.

In April 2011, the City of New York passed regulations phasing out the use of highly polluting No. 6 and No. 4 fuel oil. The City simultaneously launched the NYC Clean Heat program, which had a goal of a 50% reduction in fine particulate matter emissions from buildings burning these types of oil by the end of 2013 by transitioning buildings to the cleanest fuels (ultra-low sulfur No. 2 oil, biodiesel, steam, or natural gas) as quickly as possible. The Clean Heat Program was yet another contributing factor to load growth.

In 2018, 4.29m residences in New York State used natural gas for primary space heating, while 1.59m homes used fuel oil, 840,000 used electricity, 280,000 used propane, and the remaining 310,000 used another energy source.[70] From 2013 to 2018, the number of residences that used fuel oil as a primary space heating fuel decreased by 393,000, while the number using natural gas, electricity, and propane increased by 267,000, 128,000, and 47,000, respectively.

These differences are important in understanding the opportunities and economics of NPS in New York State and Ontario. In particular, the share of natural gas load in the residential sector is a critical differentiator between the two jurisdictions. Residential load is peakier on an hourly basis than either commercial or industrial load. As such, rapid growth in residential demand will have a disproportionate impact on the amount of peak day natural gas capacity required relative to the yearly average demand. In this case, the load factor (i.e. average demand divided by peak demand) will be lower.

The peakiness of the incremental load in New York State relative to Ontario impacts the underlying economics of different NPS alternatives. Natural gas pipeline capacity is most

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[65] U.S. Energy Information Administration, 'Natural Gas Consumption Data', 2020 <https://www.eia.gov/naturalgas/data.php#consumption> [accessed 18 August 2020].
[66] U.S. Energy Information Administration, 'New York State Profile and Energy Estimate', 2020 <https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_sum/html/> [accessed 18 August 2020].
[67] Natural Resources Canada (NRCan), 'Comprehensive Energy Use Database', 2020 <https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm> [accessed 18 August 2020].
[68] Ontario Energy Board, *Yearbook of Natural Gas Distributors - 2018*.
[69] Ontario Energy Board, *Yearbook of Electricity Distributors - 2018*, 2019 <https://www.oeb.ca/oeb/_Documents/RRR/2018_Yearbook_of_Electricity_Distributors.pdf> [accessed 20 August 2020].
[70] United States Census Bureau, 'Data Releases', 2019 <https://www.census.gov/programs-surveys/acs/news/data-releases.html?> [accessed 31 July 2020].

economic under higher load factors. The incremental cost of new pipeline capacity increases on a per unit throughput basis as the overall load factor decreases. As a result, the relative value of NPS options that reduce peak period demand increase relative to pipeline capacity as the pipeline load factor decreases. This means that NPS options will generally be a more economic to pipelines with peakier load, and for serving load growth that is peakier to begin with. Given the differences in the general load factors between Ontario and New York, ICF would anticipate NPS options to provide an economic alternative to conventional investments in pipeline capacity more frequently in New York State than in Ontario.

Constrained Areas and Moratoria on New Gas Connections in New York

The focus on NPS in New York State has been driven by public discussions related to the amount of pipeline capacity in the State, and the need to build new pipeline capacity in order to serve current demand and anticipated natural gas load growth. The long term growth trends in natural gas demand, including both customer growth and demand growth in certain areas of the State, combined with changes in natural gas supply markets serving the State and surrounding markets, and growth in demand in surrounding markets, including New Jersey and New England, has led many of areas of the State to become supply-constrained. Supply-constrained areas include ConEdison’s Westchester County service territory, ConEdison’s Manhattan and Bronx service territory, National Grid Long Island and National Grid New York’s service territories, National Grid Niagara Mohawk’s service territory in the Capital Region, and NYSEG Lansing, Oneonta, Goshen, Avon, and Le Roy’s service territories.

In many cases, the utilities in those areas have implemented moratoria on new connections to the gas distribution system or warned in regulatory filings that they may have to implement a moratorium in the near future if additional firm gas capacity is not contracted or constructed. The State is considering NPS options as alternatives to the solutions proposed by the utilities. A brief summary of the constraint areas in New York is provided below:

Moratorium in ConEdison Westchester County

ConEdison has an ongoing moratorium on new gas hookups in portions of Westchester County. The utility has stated that it will not be able to lift the moratorium on new gas hookups in the portion of Westchester County that is served by the Tennessee Gas Pipeline unless Tennessee Gas Pipeline’s 110 BBtu/day East 300 project is completed. That earliest possible completion date for that project is November 1, 2022.

Moratorium in ConEdison Manhattan and the Bronx

ConEdison also has an emerging constraint on its distribution system in lower Manhattan, which is primarily served by Texas Eastern Transmission (TETCO). ConEdison’s takeaway capacity at its city gates with TETCO is at capacity.

Moratorium in National Grid Long Island and National Grid New York

Due to the size of its load and potential for growth, one of the most noteworthy constrained areas in New York State is the service territories of National Grid Long Island and National Grid New York. The moratorium on new gas hookups that was announced in 2019 in the Long Island and New York service territories has been lifted until September 2021 but the underlying imbalance between the load growth in the service territories and the need for new gas supplies has not been solved.

The primary cause for the need for a moratorium on new gas hookups was the delay and then cancellation of the NESE pipeline project. After first applying for state permits in June 2017, NESE was repeatedly denied its Section 401 Water Quality Certification by the New York State Department of Environmental Conservation until, Williams, the project developer, decided to cancel the project due to the regulatory hurdle.

Moratorium in the Capital Region (National Grid Niagara Mohawk)

National Grid Niagara Mohawk's Capital Region takeaway capacity from the Dominion Transmission and Tennessee Gas Pipeline may soon be at capacity. The utility's application states that, "ultimately, a moratorium declaration on firm sales in the capital region of the Company's system will be needed if the constraint is not addressed."[71]

Moratorium in NYSEG

There has been an active moratorium in the Lansing, New York area since 2017 and a few other NYSEG and Rochester Gas & Electric (RGE)-served areas may experience supply limitations in the near-term. NYSEG and RGE are monitoring their Oneonta, Goshen, Avon, and Le Roy service territories for new load that may exceed their system's capacity.

Retail Electricity and Natural Gas Rates

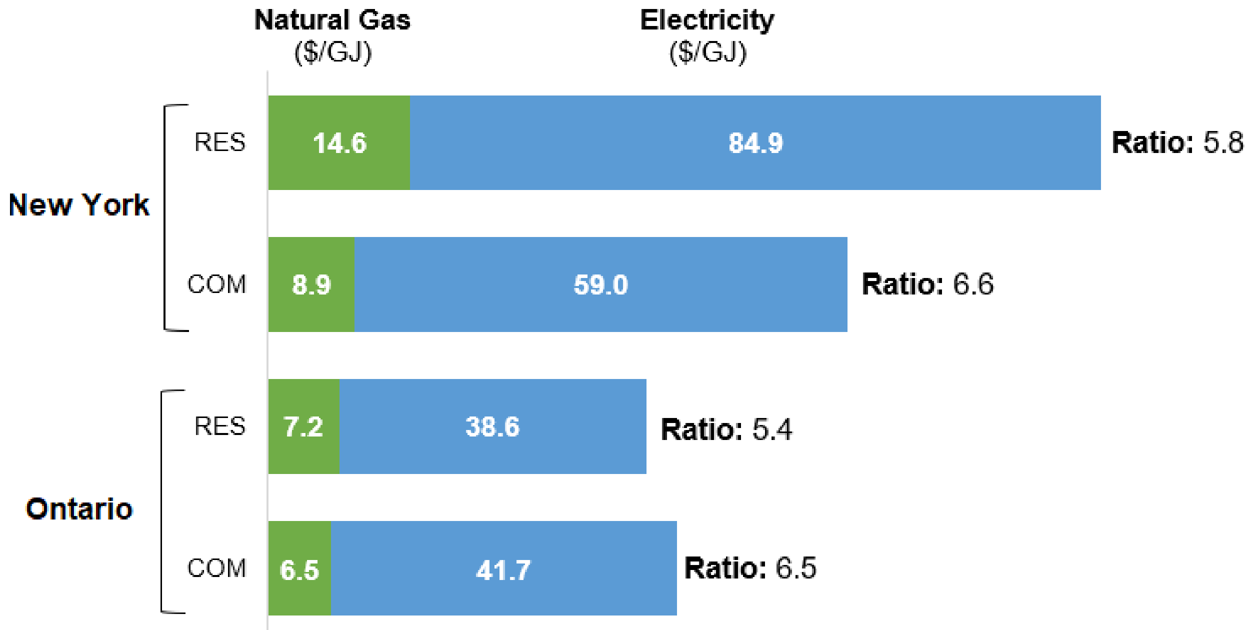
One of the major differences between Ontario and New York State that must be considered when evaluating the New York State NPS experience is the difference in energy costs in the two jurisdictions. New York State energy costs are much higher than that in Ontario, which improves the economics of programs designed to reduce energy use, including NPS and NWS options.

In 2018, the New York average residential price for natural gas was \$16.99/GJ (\$11.93 USD per MMBtu), the average commercial price was \$10.11/GJ (\$7.10 USD per MMBtu), the average industrial price was \$10.75/GJ (\$7.55 USD per MMBtu), and the average electric power price was \$5.31/GJ (\$3.73 USD per MMBtu). Gas prices are generally lower in the Upstate region where there is more gas availability from the low-cost Marcellus and Utica basins, and system development costs are lower.

[71] National Grid, *Article VII Application for a Certificate of Environmental Compatibility and Public Need*, 2019 <https://caseonlineorg.files.wordpress.com/2019/04/national-grid-e37-application.pdf> [accessed 28 July 2020].

Exhibit 11 contrasts retail rates of electricity against that for natural gas, for New York State and Ontario. All were brought to common energy units and currency for comparison purposes.

Exhibit 11 Comparison of Natural Gas and Electricity Retail Rates ($CAD) in Terms of Delivered Energy[72]



Source: Based on rates for delivered energy from Hydro-Québec[73], Enbridge[74], NYSERDA[75,76]

As summarized in Exhibit 11, the consumer rates for both natural gas and electricity are significantly higher in New York State than in Ontario. However, the difference is much larger for residential customers, with rates for residential customers in New York being about two times higher than those for residential customers in Ontario. Commercial energy rates in New York are only about 40% higher than rates in Ontario. In addition, the ratio between natural gas rates and electricity rates was found to be relatively consistent between the two jurisdictions.

Infrastructure costs are higher in Downstate New York because the area is more densely populated. In addition, buildings in New York City and the surrounding areas were built prior to natural gas service becoming ubiquitous for space and water heating in North America. This explains why fuel oil is still so prevalent in New York State. Downstate New York utilities are

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[72] These rates are not definitive rates for Ontario and New York, since rates often vary across these jurisdictions. Based on the available sources, electricity rates represent retail rates in Toronto and New York, respectively, while natural gas rates for Ontario represent typical rates for the most common customer classes and natural gas rates for New York represent statewide averages.
[73] Hydro-Québec, *2019 Comparison of Electricity Prices in Major North American Cities*, 2019 <https://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf> [accessed 30 July 2020].
[74] Enbridge Gas, 'Understanding Gas Rates', 2020 <https://www.enbridgegas.com/Understanding-gas-rates> [accessed 30 July 2020].
[75] NYSERDA, 'Monthly Average Price of Natural Gas - Commercial', 2020 <https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices/Natural-Gas/Monthly-Average-Price-of-Natural-Gas-Commercial> [accessed 30 July 2020].
[76] NYSERDA, 'Monthly Average Price of Natural Gas - Residential', 2020 <https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices/Natural-Gas/Monthly-Average-Price-of-Natural-Gas-Residential> [accessed 30 July 2020].

also completing costly projects to replace old cast iron pipelines and construction work in the area can be difficult due to urbanized roadways with many utility conflicts and traffic issues.

The higher consumer rates in New York are reflective of the higher cost of delivering electricity and gas to Downstate New York, and the higher costs of maintaining transmission and distribution infrastructure in general. This has led to a stronger economic justification for conservation efforts in New York State generally, as well as for NPS.

New York State Energy Research and Development Authority (NYSERDA)

Established in 1975, the New York State Energy Research and Development Authority (NYSERDA) is a public-benefit corporation with a long history of providing objective information, analysis, and technical expertise to promote EE and clean energy solutions. It coordinates with utilities, to deliver EE programs and plays a key role in many of the critical policies that are encouraging and sustaining the energy transition in New York State.

There is no direct equivalent to NYSERDA in Ontario. The IESO plays some of the roles of NYSERDA, but not all of them. One key difference: NYSERDA is a "multi-fuel" agency while the IESO focuses only on electricity.

The source of funding for the NYSERDA programs is the Clean Energy Fund, collected through a system benefit charge and renewable portfolio standard in ratepayer's energy bills. The PSC authorized $6.7b ($5.322b USD) over a 10-year period. The distribution utilities began collaborating and sharing customer program responsibilities with NYSERDA.

In the context of natural gas and NPS, NYSERDA recently received approval of $7.11m ($5.27m USD) in funding for a Consumer Awareness initiative. This initiative will be focused on education and outreach strategies to increase the adoption of clean heating and cooling and other EE technologies. This will expand the reach of other NYSERDA and utility programs, helping to maximize benefits from these technologies in natural gas system constraint areas.

Climate Leadership and Community Protection Act

In 2019, New York State passed the Climate Leadership and Community Protection Act (CLCPA). The CLCPA entails:

- The bolstering of the previous renewable energy portfolio standard from 50% of sourcing from renewable energy by 2030 to 70% from non-emitting sources by 2030 and 100% by 2040.
- Commitment to achieve a net-zero carbon economy by 2050, with 85% coming from in-state reductions of emissions and only 15% from carbon credits from out of state.
- A statewide goal of reducing energy consumption by 196m GJ per year (185 trillion British thermal units or TBtu) from the state's 2025 forecast through EE improvements.

The portion of the CLCPA that mandates that the New York State economy reach carbon-neutrality by 2050 will have a direct impact on the operations of natural gas utilities in the state. The gas utilities and regulators are engaged in long-term planning to determine the role that gas utilities will play in helping New York State reach the goal of carbon-neutrality by 2050. However, gas utilities will likely be required to use EE, DR, RNG supply, hydrogen blending, and other demand and emissions reduction methods.

For instance, NYSEG and RGE's most recent rate case, which was settled in June 2020, includes commitments to support New York State's clean energy future by working towards a net-zero increase in gas usage. That commitment involves incentives for using heat pumps and continuing to fix all leaks in the gas system each year. The plan also provides for the implementation of advanced metering infrastructure for both electric and gas customers to help them better manage their energy usage. Meter installations are scheduled to begin in 2022 and be completed within three years.

In addition, NYSERDA has been instrumental in coordinating, performing analytics, providing direction, and overseeing large renewable procurement processes.

New Efficiency: New York

In alignment with REV and the CLCPA, NYSERDA issued the "New Efficiency: New York" report, setting a state target of 196m GJ (185 TBtu) of customer-level energy reductions below the 2025 energy-use forecast, an incremental 33m GJ (31 TBtu) by state utilities. Utility budgets will also be increased by $2.04b ($1.51b USD).[77] In the Order Adopting Accelerated Energy Efficiency Targets, which was issued in December 2018, the PSC formally adopted the targets and budgets laid out in the New Efficiency New York report.

The Order also established utility targets and budgets for 2019-2020 and a process for developing utility-specific targets for the years 2021-2025. The New Efficiency framework encouraged utility portfolios to include more comprehensive EE measure mixes, new program structures that reflect grid value, and program cost effectiveness improvements and to better leverage public and private funds. As part of the comprehensive EE programs, NWS and NPS are recognized as having important roles in achieving the targeted savings.

Importantly, *electric* utilities were given targets (and correspondingly substantial budgets) to promote the adoption of heat pumps in all sectors of the economy. This budget and target can potentially be used to implement gas-to-electricity conversions; perhaps in areas of high constraint on the gas distribution network. However, it is primarily focused on oil-to-electricity and electric resistance heating-to-heat pump conversions as these opportunities offer better financial results for participating customers than gas-to-electric conversions.

The fact that most utilities in New York State are joint gas and electric utilities may also encourage electrification of heating demand. Programs encouraging EE and DR as well as pilot programs for RNG are already underway in New York State. In the long-term, retail prices for natural gas may increase as the penetration of higher-cost RNG increases and spending on integrity management programs are included in future rates.

Broad-based DSM Framework

New York State's efforts to develop NPS draw on extensive experience with DSM programs. New York State has been one of the most aggressive jurisdictions with respect to implementing and funding DSM programs. While not directly intended to reduce the need for specific investments in new pipeline capacity, the DSM programs have impacted New York State load growth and reduced peak day demand and the need for new capacity.

The DSM efforts in New York State have been driven by a sequence of legislative and regulatory mandates, with the latest being the Accelerated Energy Efficiency Order.

Before the Accelerated EE Order, New York State's Energy Efficiency Portfolio Standard was established in 2008 and was authorized through the end of 2015. Under the Energy Efficiency Portfolio Standard, utility efficiency programs were resource acquisition programs with direct rebates and subsidies to foster customers adoption of EE technologies to reduce electricity and gas consumption.[78]

[77] NYSERDA, *New Efficiency: New York*.
[78] American Council for an Energy-Efficient Economy (ACEEE), 'State and Local Policy Database', 2019 <https://database.aceee.org/state/new-york> [accessed 18 August 2020].

As part of the 2015 Reforming the Energy Vision Order, the PSC established a new EE program framework for electric and gas distribution companies, both assigning increased responsibility and granting increased flexibility and directing them to use market-based approaches to drive greater customer value. The goal was to gradually evolve to align with the innovative approaches articulated in the Reforming the Energy Vision (REV) initiative (more details on REV are included later in this report). The REV also focused NYSERDA on market transformation.

This framework allowed utilities to design and manage programs within authorized portfolio budgets, as opposed to specific programs under the Energy Efficiency Transition Implementation Plan. In addition, the utilities had to assume responsibility for the development and update of the technical resource manual as well as a BCA Framework[79] that would also apply to EE and DER.

The PSC's June 19, 2015 Order directed New York State gas utilities to also plan and implement EE programs.[80] Later, with its January 2016 Order, the PSC authorized 2016-2018 EE budgets and targets for electric and gas distribution companies, representing budgets of approximately $909m[81] ($673m USD) for electric and $261m ($193m USD) for gas, while the proposed targets were 1,857 GWh and 175m m^3 (6,414,526 Dth), respectively.[82] Since 2017, the utilities began transitioning DSM program costs from bill surcharge to a more integrated approach, recovering costs through rates, like other revenue requirements but tied to utility-specific performance incentives through earnings adjustment mechanisms.

In its December 2018 Order (the Accelerated EE Order), the PSC continued the EE activities started in the REV framework and subsequent Orders and authorized new expanded budgets and targets for 2019-2020 and 2021-2025.

The utilities have incremental 2021- 2025 EE targets and budgets, inclusive of the integration of NWS and NPS. The Order acknowledges the concept of "incentive kickers" in areas with supply constraints – similar to the electric incentive kicker used in targeted programs or NWS – and encouraged the utilities to consider them in future proposals to create system value.

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[79] NY Public Service Commission, *Order Establishing the Benefit Cost Analysis Framework*, 2016 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7D>.

[80] NY Public Service Commission, *Case 07-M-0548 & Case 15-M-0252 - Order Authorizing Utility-Administered Gas Energy Efficiency Portfolios for Implementation Beginning January 1, 2016*, 2015 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BCFD3F560-0295-4824-B11D-C37812B8A710%7D> [accessed 18 August 2020].

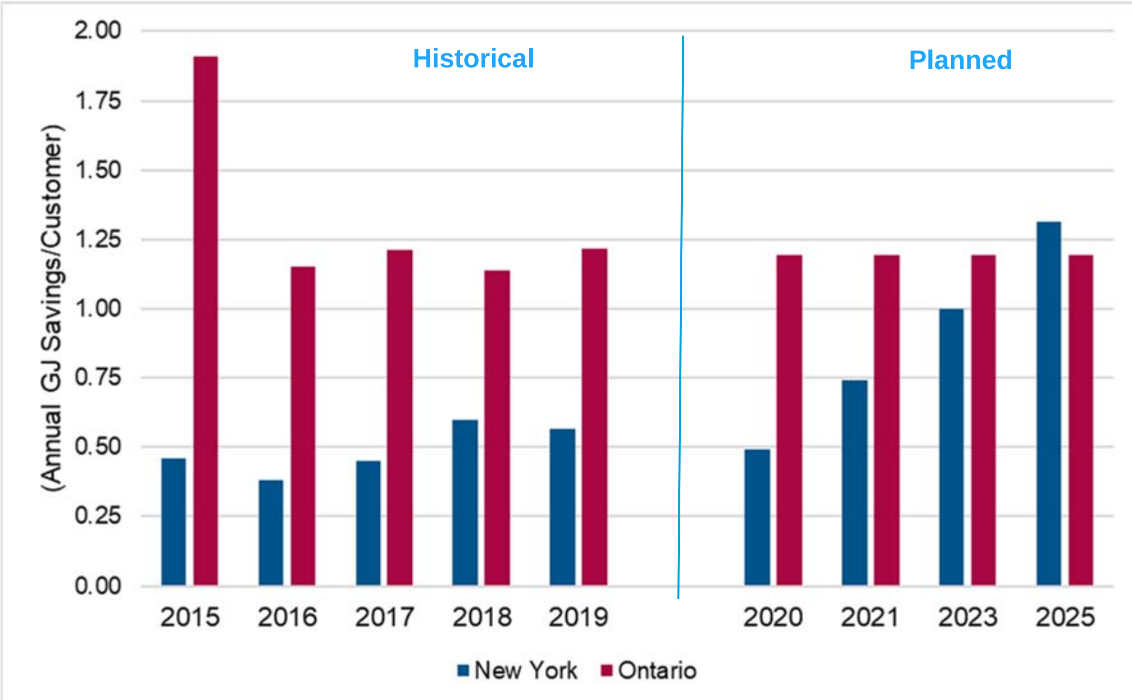
[81] The exchange rate used in this entire report is 1 USD = $1.35 CAD

[82] NY Public Service Commission, *Case 15-M-0252 - Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2016-2018*, 2016 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B37C417DD-AEE4-470F-BB71-79878BA2EB18%7D> [accessed 18 August 2020].

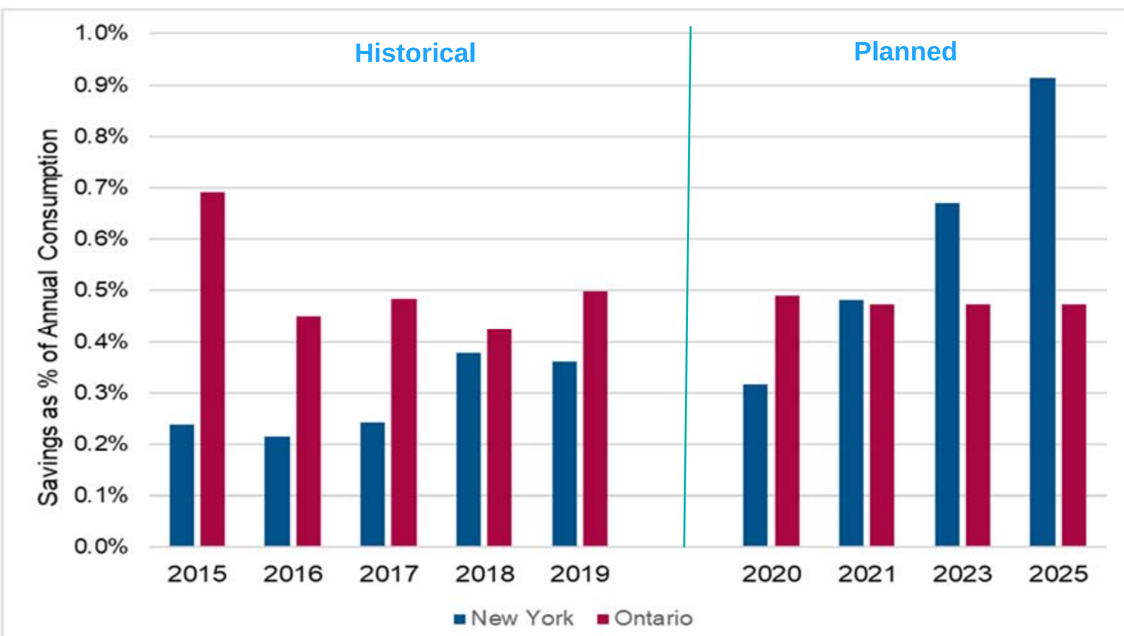
ICF collected historical gas EE results, and forward-looking gas EE targets, both for Ontario and NY. The results of our research are presented in Exhibit 12 and Exhibit 13.

Exhibit 12 Natural Gas Energy Efficiency Impact (net)

Broad-Based EE Annual GJ Savings/Customer)[83]



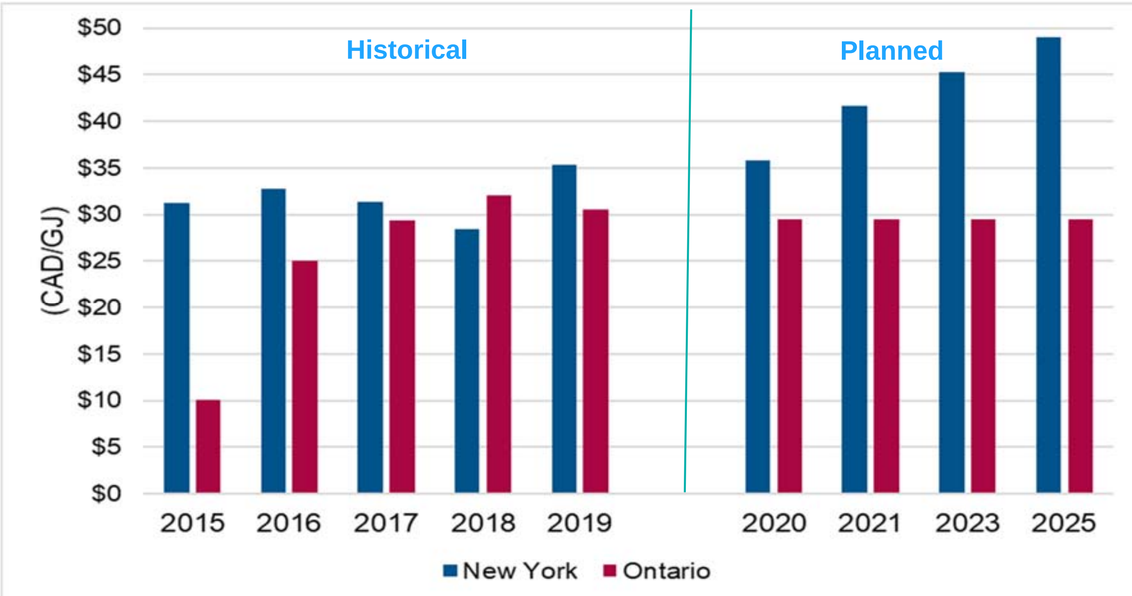
Savings as % of Annual Consumption from Natural Gas Broad-Based EE Programs[84]



Sources: New York data: E Source[85], NY Public Service Commission[86] and EIA[87]; Ontario data: OEB[88], Enbridge[89]

As seen in Exhibit 13, before the Accelerated EE Order, Ontario gas DSM was ahead in terms of realized gas savings (in terms of % of sales) and had a similar cost of acquisition of the savings (in $CAD). With the new Accelerated EE Order, New York State is projected to catch up with Ontario and surpass it in terms of gas savings targets. Moreover, the New York State gas utilities were given more budget on a per-unit-saved.

Exhibit 13 Natural Gas Broad-Based EE Cost ($CAD/GJ Annual Savings)



Sources: New York data: E Source[90], NY Public Service Commission[91] and EIA[92]; Ontario data: OEB[93], Enbridge[94]

Exhibit 13 shows that New York State is planning to provide the gas utilities with the financial means – the budget – to achieve greater savings targets. As can be seen, the cost of acquisition of savings has been comparable between Ontario and New York from 2017 to 2019. Between 2020 to 2025, the cost of acquisition is expected to remain flat in Ontario while in New York State, it is poised to increase significantly.

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[83] Planned budget and savings target of Ontario for 2002-2025 are considered same as 2021.
[84] Planned budget and savings target of Ontario for 2002-2025 are considered same as 2021.
[85] ESource, 'DSM Insights', 2020 <https://www.esource.com/about-dsminsights> [accessed 18 August 2020].
[86] NY Public Service Commission, *Case 18-M-0084 - In the Matter of a Comprehensive Energy Efficiency Initiative - Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B06B0FDEC-62EC-4A97-A7D7-7082F71B68B8%7D> [accessed 18 August 2020].
[87] U.S. Energy Information Administration, 'Number of Natural Gas Consumers - New York', 2020 <https://www.eia.gov/dnav/ng/ng_cons_num_dcu_sny_a.htm> [accessed 18 August 2020].
[88] Ontario Energy Board, *Yearbook of Natural Gas Distributors - 2018*.
[89] Enbridge Gas, *Draft 2019 Demand Side Management Annual Report, May 29, 2020*, 2020 <https://www.oeb.ca/sites/default/files/EGI-2019-Draft-DSM-Annual-Report-20200529.pdf> [accessed 31 July 2020].
[90] ESource.
[91] State of New York Public Service Commission, 'Case 18-M-0084, Order Authorizing Utility Energy Efficiecny and Building Electrification Portfolios Through 2025', 2020.
[92] U.S. Energy Information Administration, 'Number of Natural Gas Consumers - New York'.
[93] Ontario Energy Board, *Yearbook of Natural Gas Distributors - 2018*.
[94] Enbridge Gas, *Draft 2019 Demand Side Management Annual Report, May 29, 2020*.

Ontario Broad-based Gas DSM

Similar to New York State, Ontario has been a leader in developing and implementing DSM programs. As in New York State, DSM programs have not been implemented with the direct intent of avoiding specific infrastructure investments. However, the reduction in Ontario gas demand as a result of the DSM programs has slowed demand growth in the Province and reduced the need for investments in new pipeline capacity.

Enbridge has been delivering DSM programs under successive OEB frameworks for nearly 25 years and has saved its customer 30b m^3 of natural gas (lifetime savings). Enbridge's Draft 2019 DSM Annual Report[95] notes that the utility spent $138.4m on its conservation efforts in 2019 and achieved over 2b m^3 (lifetime) of natural gas savings. DSM budgets for 2020 are similar to that for 2019, representing approximately 5.5% of distribution revenue in the EGD Rate Zone and 8.0% of distribution revenue in the Union Rate Zone. Current DSM spending is more than double the spending in 2015. However, net annual natural gas savings have been relatively flat since 2015 in the EDG Rate Zone and have fallen in the Union Rate Zone.

Enbridge has several DSM program offerings in its DSM portfolio, including resource acquisition programs, low-income programs, performance-based programs, large volume programs, and market transformation programs that are available to its residential, commercial, and industrial customers. Currently, Enbridge proposes annual DSM targets for each program type based on the amount of natural gas savings and program activity available within the budget parameters established by the OEB. The targets are then subject to a regulatory review process, before being approved by the OEB.

Enbridge is currently operating within it 2015-2020 DSM Framework, as directed by the OEB.[96] With the existing framework set to expire on Dec. 31, 2020, the OEB has also initiated a consultation to consider the structure of the post-2020 framework and Enbridge is participating in this process.[97] In late 2019, Enbridge filed a request for the OEB to issue an extension of the current DSM Framework for one additional year, along with an application to extend OEB-approved DSM plans to 2021. To date, an OEB decision on this request has not been established.

In Ontario, gas utilities are rewarded by a performance incentive known as shareholder incentive, similar to New York State's earnings adjustment mechanism, to encourage utilities to reach or even exceed their gas savings targets. In recent years, the OEB has transitioned to a scorecard approach to reward performance against savings targets and allow for Enbridge to be rewarded for undertaking other important initiatives, such as increasing the proportion of EE measures with longer lifetimes.

Exhibit 13 showed that broad-based gas DSM impact in Ontario and in New York State are comparable. Ontario has higher targets respective to number of customers, but Ontario has more large industrial customers which explains the discrepancy. Ontario has had higher savings in 2015 and before, but it declined over time to approach the savings in New York State, relative to percentage of annual consumption. Now with the Accelerated Energy Efficiency Order, the

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[95] Enbridge Gas, *Draft 2019 Demand Side Management Annual Report, May 29, 2020*.
[96] Ontario Energy Board, *EB-2014-0134 - Report of the Board - Demand Side Management Framework for Natural Gas Distributors (2015-2020)* (Toronto, Ontario, Canada, 2014) <https://www.oeb.ca/oeb/_Documents/EB-2014-0134/Report_Demand_Side_Management_Framework_20141222.pdf>.
[97] Ontario Energy Board, 'Post-2020 Demand Side Management (DSM) Framework for Natural Gas Distributors', 2019 <https://www.oeb.ca/industry/policy-initiatives-and-consultations/post-2020-demand-side-management-dsm-framework> [accessed 31 July 2020].

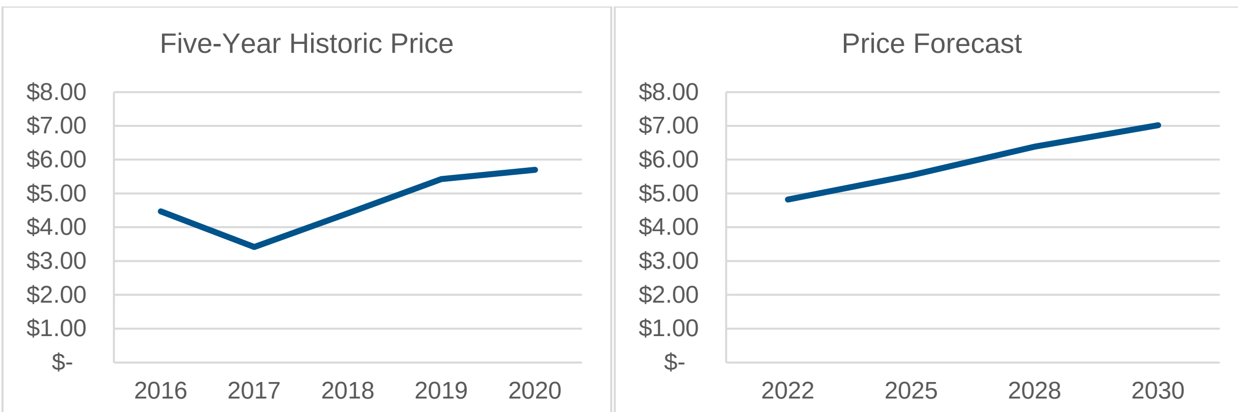
New York State utilities will have the challenge of significantly ramping up their savings to levels much higher than those in Ontario.

4.3 Role of Carbon Policy on NPS

Ontario has adopted a broader carbon pricing mechanism and the carbon price in Ontario is also higher than it is in New York State. As a result, Ontario can more heavily rely on the carbon emission suppression effect of carbon pricing. Meanwhile, New York State has relied on policies such as the Accelerated EE Order and the CLCPA to reduce carbon emissions. NPS options are therefore more critical in New York State than they are in Ontario.

New York State has a form of carbon pricing in the power sector since the State participates in the Regional Greenhouse Gas Initiative (RGGI). RGGI is a regional cap-and-trade carbon pricing program spanning over 10 states in the Northeastern United States. The program is focused on the electricity sector only and covers fossil-fuel-fired electric power generators with a capacity of at least 25 MW in the participating states. RGGI historical and forecasted prices are presented in Exhibit 14.

Exhibit 14 RGGI Prices in Nominal $USD per Metric Tonne[98,99]



Both historical and forecasted RGGI prices are lower than most estimates of the social cost of carbon. While the carbon price influences the power generation supply mix, the RGGI price is not expected to have a significant impact on electricity consumption, and will not impact natural gas consumption outside of the power generation sector.

Meanwhile, Ontario has a more exhaustive carbon pricing system than New York State. Ontario's carbon pricing mechanism is based on the Canadian federal government's carbon pricing backstop, created by the Greenhouse Gas Pollution Pricing Act that came into force in 2018.[100] Under the federal backstop, the economy-wide carbon price is set at $30/tonne in

98 State of New Jersey, *2017 RGGI Model Rule - NJ Rutgers 2018 Policy Case - VA+NJ (18) in RGGI*, 2018 <https://www.state.nj.us/dep/aqes/docs/NJ_Policy_Case_IPM_Model.xlsx> [accessed 24 July 2020].

99 Regional Greenhouse Gas Initiative (RGGI), 'Allowance Prices and Volumes', 2020 <https://www.rggi.org/auctions/auction-results/prices-volumes> [accessed 20 August 2020].

100 *Greenhouse Gas Pollution Pricing Act (S.C. 2018, c. 12, s. 186)*, 2018 <https://laws-lois.justice.gc.ca/eng/acts/G-11.55/> [accessed 3 September 2020].

2020, rising to $50/tonne by 2022.[101,102] The federal backstop pricing scheme will apply to both the gas sector and the electricity sector.

New York State has ruled out a carbon price but state policy makers appear to be committed to using other means to curb carbon emissions, such as utility-based DSM and a renewable portfolio standard as prescribed the CLCPA.

Carbon Valuation in New York State

Carbon valuation is also important to consider since it has implications on the BCA of both broad-based DSM, NPS, and NWS. Although the New York State carbon pricing scheme is modest and does not cover natural gas, New York State uses the EPA's 2017 social cost of carbon, which is pegged at $42 USD in 2020, to give a value to carbon in its BCA. This value feeds into utility-based program and policy decisions and is similar to the economy-wide carbon price in Ontario.

In addition, utility performance incentives for NWS in New York State are tied to the results of the BCA. This means that the social cost of carbon has a direct impact on the utility performance incentive. A higher carbon valuation would thereby mean higher performance incentive for the utilities and this has an impact on the earnings of the investor-owned utilities.

These details highlight how policymakers in New York State have added a valuation of the externalities due to carbon emissions to the BCA framework.

Due to the modest carbon pricing model and low carbon price in New York State, the State must rely on the CLCPA, the Accelerated EE Order, NWS, and NPS to achieve decarbonization. By contrast, Ontario already has a carbon price applicable to most of its economy, which applies downward pressure on carbon emissions. The different approaches to the valuation of carbon emissions also impact policy decisions in the two jurisdictions.

4.4 Implications of the Electric Utility Experience with NWS

In the jurisdictions that we reviewed as part of this assessment, Non-Wires Solutions (NWS) programs for the electric industry generally are more advanced than NPS programs for the natural gas industry. In particular, the New York State experience with NWS has been instrumental in setting the stage for NPS for the gas industry. In addition, some of the NPS options under consideration directly impact the electric grid. As a result, the NWS experience in New York State is relevant to the development of NPS in the State, and hence to Ontario.

Gas to Electric NPS

Electrification of current and projected future growth in natural gas demand through the adoption of heat pumps (Gas to Electric, or G2E conversion) is a potentially significant option being contemplated as an NPS solution in New York State. New York State's Accelerated EE Order requires utilities to promote heat pumps, which are likely to substitute fossil fuel-based space and water heating systems. G2E conversion makes most sense in a jurisdiction that also has a commitment to decarbonize its electricity grid. If natural gas electricity generation stays at the

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[101] The carbon price will show on the gas bill of Ontario ratepayers as a separate line item which covers the compliance obligation attributed to end user gas consumption. The carbon price in 2020 translates to 5.87¢/m^3 increasing to 9.79¢/m^3 by 2022. The cost to the average residential customer is estimated at $141 per year in 2020.

[102] Enbridge Gas, 'Federal Carbon Charge'.

margin and is the expected incremental capacity, then the result of G2E is more GHG emissions than the electrification was meant to offset.

Both Ontario and New York State currently have a relatively low-carbon electricity generation mix. As in Ontario, there are no longer any coal-fired powerplants in New York State.[103] In 2019, most of the New York State's capacity came from thermal resources such as combined cycle plants, combustion turbines, and steam turbines. Nuclear and hydroelectric facilities added up to over 10 GW of capacity, with wind capacity increasing to approximately 2 GW by the end of 2019. The largest source of capacity in Ontario's electricity grid is nuclear power. Ontario's generation mix is primarily non-emitting, with natural gas capacity providing less than 10 TWh of generation in 2019.

Both Ontario and New York State are summer peaking power generation jurisdictions, hence the jurisdictions generally have excess generating capacity during peak winter periods, which provides additional flexibility. In New York, most of the gas-fired power plants rely on interruptible supply arrangements, and do not hold firm pipeline capacity. As a result, power generation does not contribute significantly to firm gas requirements or peak day natural gas demand, and the changes in power generation gas requirements will have only limited impact on pipeline requirements in the jurisdiction. Conversely, the majority of natural gas power plants in Ontario currently hold firm pipeline capacity, and changes in natural gas power generation are more likely to impact pipeline requirements than in New York State. As a result, changes in Ontario power generation are likely to impact the need for NPS in the future, while NPS in New York will be largely isolated from changes in power generation demand.

Over the next decade, the development of the generation mix in New York and Ontario is expected to diverge due to the impacts of emission reduction policies in New York State and changes to the supply mix in Ontario, with upcoming nuclear facility retirements. While the supply mix in Ontario is expected to include more gas-fired capacity and generation, the supply mix in New York State is expected to become less carbon-intensive due to the CLCPA.

In Ontario, the IESO's January 2020 Annual Planning Outlook, June 2020 Reliability Outlook, and July 22 "Forecasting and Planning Update" session forecast increasing natural gas-fired generation. The retirement of over 3 GW of nuclear capacity in Ontario is projected to lead to more than a doubling of gas-fired generation between 2020 and 2030. By 2040, the IESO projects that gas-fired generation will increase to 37 TWh to meet growing electric demand in the province.

Meanwhile, with the CLCPA New York State has adopted one of the most aggressive clean energy and emission reduction targets for the power sector. It mandates that 100% of New York State's electric demand be supplied by non-emitting sources by 2040. To support the achievement of these targets, the CLCPA has included several interim targets and mechanisms:

- By 2030, 70% of the state's electricity generation will need to be sourced from renewable energy.
- The CLCPA includes a set of resource procurement targets that will increase the penetration of renewables in the state:
  - 9,000 MW of offshore wind capacity by 2035
  - 6,000 MW of distributed solar energy capacity by 2025
  - 3,000 MW of energy storage capacity by 2030

The CLCPA target, along with the nuclear capacity remaining in the state by 2030, will reduce the amount of fossil generation significantly below current levels. NYISO's Congestion

[103] The last coal powerplant in New York State shut down in March 2020

Assessment and Resource Integration Study projects fossil generation in 2030 at half the generation compared to 2019 levels.[104]

Under the current policies, NPS options based on G2E in New York State will add electricity load primarily from non-emitting sources. However, G2E in Ontario would lead to additional natural gas capacity and generation. As a result, G2E in Ontario will be more carbon-intensive than the status quo.

Electricity Non-Wire Solutions

One of the driving forces behind the support for NPS in New York State has been the relatively successful experience with NWS in the State. The NWS efforts have been helpful to the development of NPS because many of the gas utilities in the state are part of joint power and gas utilities or are owned by parent companies that own both power and gas utilities. The critical characteristics of the New York State and Ontario power markets that have driven the NWS experience in these two jurisdictions are highlighted below.

Illustrating this cross-pollination, ConEdison recently published a framework for NPS that is similar to its NWS framework. The NPS framework is mentioned in the utility's 2020 Distribution System Implementation Plan[105] and follows a direction from the PSC. As a result of these developments in New York State, the approach to electricity system planning in the presence of DER, and incorporating NWS on routine basis, is of particular interest.

Electricity Distribution

There are 22 electric distribution companies in New York State. Six are major investor-owned utilities serving a total of 5.54m customers (82% of customers);[106] ConEdison, NYSEG, RG&E, Orange and Rockland, National Grid Niagara Mohawk and Central Hudson. All of the investor owned companies distribute both gas and electricity. The remaining distribution companies include one state-owned utility (PSEG Long Island Power Authority (LIPA)) and 13 municipal and cooperative utilities. The municipal and cooperative utilities are not regulated by the PSC.

The electric utilities are regulated by the PSC with a similar mandate as that for gas, with the same cost-of-service rate regulation, and the same approach with respect to the use of utility performance incentives (i.e. earnings adjustment mechanism) to drive outcomes.

In Ontario, the electricity distribution system is owned by one investor-owned utility, Hydro One, and 63 municipally owned utilities. All of these entities are regulated by the OEB. Ontario's municipally owned utilities tend to be more risk-averse because they are municipally owned. This structure may result in a lower motivation on their part to pursue new revenue-generating endeavors such as those associated with DER. They are also perhaps not as focused on incentives or motivators to consider NWS and DER.

Furthermore, many Ontario utilities are small. The top three largest Ontario utilities (i.e. Hydro One, Alectra, and Toronto Hydro) are of comparable size to large Downstate New York utilities, while the following top 12 Ontario utilities are of comparable size to the Upstate New York

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[104] NY Independent System Operator, *Electric System Planning Working Group, 2019 CARIS 70x30 Scenario: Preliminary Constraint Modeling, Nuclear Sensitivity and Additional Results*, 2020 <https://www.nyiso.com/documents/20142/11350020/04 2019CARIS1_70x30Scenario.pdf/202a845b-6026-6f43-c1dc-55ba3a016d48> [accessed 31 July 2020].

[105] ConEdison, *Distributed System Implementation Plan*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B8ED58C88-FB25-4E7E-BB66-A9DA9FCDEEDD%7D> [accessed 24 July 2020].

[106] There are eight investor-owned utilities, Pennelec and Fishers Island Utility is an investor-owned utility serving 762 customers. Pennsylvania Electric Co is an investor-owned utility serving 3,524 customers. They are regulated by the PSC yet are not part of the REV.

utilities. The remaining 51 Ontario distribution companies are considerably smaller. Consequently, their access to resources is more limited.

Given the large diversity in the skillsets and levels of resource accessibility between the larger and smaller utilities, Ontario policymakers tend to define rules and initiatives that fit the ambitions and capabilities of both groups. This dynamic has influenced the progress that is being made on DER policies in the province.

Reforming the Energy Vision (REV) Initiative

New York State's success with respect to NWS is generally believed to be largely due to "Reforming the Energy Vision" (REV), a policy initiative launched by Governor Andrew Cuomo in 2014. REV entails quantitative targets for EE, renewables, DER, storage, and electric vehicles. The six major investor-owned utilities are part of REV. LIPA has not been part of REV, but is now slowly being integrated into the REV requirements.

The REV vision is to develop an integrated energy network (i.e. electricity, gas, and other fuels) able to harness the benefits of the central grid with clean and locally generated power (including DER). REV was meant to reorient both the electric industry and the ratemaking paradigm towards a consumer-centered approach to harnessing technology and markets.[107] REV calls for DER to be integrated into utility planning, operations, and markets to achieve optimal system efficiency, affordability, and diversity and enable a reliable and resilient grid.[108] NPS efforts in New York State have also benefited to a lesser extent from the structure put in place as part of this initiative.

New York State's electric utilities have largely bought into the REV process. They have already made investments and are contemplating additional investments to support a more flexible system that can effectively integrate a significant increase in clean DER to provide customer benefits and increase customer satisfaction, decarbonize the economy, and increase climate resiliency.

REV preceded the 2015 State Energy Plan[109] and the Governor's 2018 clean energy agenda.[110] REV also preceded the CLCPA[111] and New Efficiency New York (and the corresponding Accelerated EE Order). The CLCPA was inspired by and aligned with REV, while the CLCPA targets superseded the targets in REV. The result is a frequent string of clear, coherent, top-down policy direction received and largely followed by the PSC, the electric utilities, and the gas utilities.

In alignment with REV, the PSC's REV Track Two Order created new frameworks for ratemaking and revenue models, including the ability to create new earnings adjustment mechanisms to incentivize utilities to take actions that achieve the REV objectives. Each utility

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[107] New York State, '2015 New York State Energy Plan'.
[108] NY Public Service Commission, *CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision: Order Adopting a Regulatory Policy Framework and Implementation Plan*, 2015 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0B599D87-445B-4197-9815-24C27623A6A0%7D> [accessed 24 July 2020].
[109] New York State, *2015 New York State Energy Plan - Overview*, 2015 <https://energyplan.ny.gov/-/media/nysenergyplan/2015-overview.pdf> [accessed 24 July 2020].
[110] New York State, 'Governor Cuomo Announces Dramatic Increase in Energy Efficiency and Energy Storage Targets to Combat Climate Change', 2018 <https://www.governor.ny.gov/news/governor-cuomo-announces-dramatic-increase-energy-efficiency-and-energy-storage-targets-combat> [accessed 24 July 2020].
[111] Natural Resources Defense Council (NRDC), 'Unpacking New York's Big New Climate Bill: A Primer', 2019 <https://www.nrdc.org/experts/miles-farmer/unpacking-new-yorks-big-new-climate-bill-primer-0> [accessed 24 July 2020].

proposes their own performance areas, metrics, targets, and incentives levels for the PSC's approval.

ConEdison was the first utility to include earnings adjustment mechanisms in their 2017 and 2019 rate cases, including incentives linked to achievement of EE, system peak reductions, DER integration, energy intensity across service classes, and carbon reductions. In addition, a portion of the utility's EE and peak reduction programs, such as NWS, are treated as regulatory assets with a 10-year amortization period and a return on equity.[112] In 2019, ConEdison's performance exceeded the maximum stretch targets for five of its seven earnings adjustment mechanisms.[113]

In their 2018 electric and gas rate case proposal, National Grid proposed four electric earnings adjustment mechanisms (with eight metrics) and one gas earnings adjustment mechanism (with one metric). Revenues from the earnings adjustment mechanism range from $0.8m CAD ($0.6m USD) to $3.5m CAD ($2.6m USD) for the 2018-2020 performance period.[114]

The Joint Utilities of New York

The Joint Utilities of New York (JUNY) is an association of utilities, grouping ConEdison, NYSEG, Orange and Rockland, National Grid and Rochester Gas & Electric Company, created to collaborate in their participation in the REV process. The JUNY have hosted and participated in multiple stakeholder meetings through the REV process to gather input and collaborate across many topics, such as customer programs, electric vehicles, data access, DER interconnection, DER market participation, among others.

The JUNY group does not currently play a similar role for NPS. Given the number of JUNY members that are joint gas and electric utilities, the JUNY model represents a logical approach to support collaboration on gas infrastructure avoidance and NPS.

Early NWS Projects in New York

ConEdison pioneered the integration of EE into T&D planning even before the REV. The utility started geo-targeted EE in 2003, when growth in demand had created areas of high constraint in their distribution network. Contracts were established with third-party vendors to provide load reductions in targeted areas. The only cost-effective bids continued to be geo-targeted EE solutions until 2010.[115] More recently, ConEdison has implemented several groundbreaking NWS projects going beyond geo-targeted EE solutions:

- **Brooklyn Queens Demand Management (BQDM) Project**: ConEdison filed a petition with the PSC on July 15, 2014 proposing to implement NWS to offset the need for 52 MW of incremental distribution capacity, including 11 MW of non-traditional, utility-side solutions and 41 MW of traditional, customer-side solutions. The program was approved to be implemented with a $270m ($200m USD) budget. BQDM aimed to delay the construction of

[112] American Council for an Energy-Efficient Economy (ACEEE), 'Snapshot of Energy Efficiency Performance Incentives for Electric Utilities', 2018 <https://www.nyserda.ny.gov/Abouthttps://www.aceee.org/sites/default/files/pims-121118.pdf> [accessed 20 August 2020].
[113] ConEdison, *March 2020 Update & 2019 Earnings Release Presentation*, 2020 <https://investor.conedison.com/static-files/72299589-a2fe-412e-a9f5-7ff8cb80e72a> [accessed 20 August 2020].
[114] National Grid, *Case 17-E-0238, Case 17-G-0239, Case 14-M-0042, Case 12-G-0202 - Joint Proposal*, 2018 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BC43AA3B9-3E5B-44C6-937E-63B3729A4D87%7D>.
[115] Chris Gazze and others, 'ConEdison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction', in *ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5*, 2010, pp. 117–29.

a new substation by reducing load with non-traditional resources. This project demonstrated the ability to leverage a diverse portfolio of DER to drive demand reduction and defer traditional infrastructure upgrades that would otherwise require a large investment.

ConEdison's traditional approach to address the potential overload of the sub-transmission feeders Brownsville No. 1 and No. 2 substations would have been to construct a new area substation, establish a new switching station on the existing property of the Gowanus station, and construct sub-transmission feeders between the new Gowanus switching station and the new area substation by 2017. Instead, the utility decided to defer that investment by implementing a combination of traditional and non-traditional customer-side and utility-side solutions.

ConEdison used a mix approach to source the resources for BQDM with an open solicitation process, grid-based NWS projects, and enhanced EE incentives (incentive kickers) to existing or new customer programs – incremental to its existing broad-based EE programs – to incentivize adoption of EE measures in the identified areas of need. Implementation first started with EE initiatives that leveraged existing programs.

For the BQDM NWS, ConEdison received a performance incentive, earning a rate of return on program costs based on several metrics, generally based on a 50/50 split of the project benefits. However, the 50/50 incentive structure was later modified to 30% annual net benefits[116] after ConEdison launched yet another early NWS, as presented below.

- **ConEdison – Water St. / Plymouth St.:** Following the BQDM, ConEdison implemented another NWS with 21 MW of load relief at Water Street/Plymouth Street.

The PSC acknowledged that strictly limiting ConEdison to cost recovery mechanisms would be a poor incentive since they will deploy less capital-intensive assets, resulting in reduced earnings. To address this issue, ConEdison proposed an additional shared savings incentive mechanism to allow shareholders to make up for the foregone earnings and motivate the utility to pursue NWS despite the reduction in capital investment.

The PSC approved a revised incentive for future NWS projects (and the BQDM extension), which allowed Con Edison to earn 30% of the annual benefits and use a 10-year accelerated depreciation, shorter than traditional capital investments.[117]

As a result of these early NWS projects, ConEdison formalized the NWS process, including project identification and evaluation, which became embedded in the capital planning process. The new formal process resulted in eight new NWS solicitations, totaling 160 MW since 2017.[118]

ConEdison's early NWS projects led to an increased level of comfort with no-infrastructure options resources in place of traditional distribution system infrastructure investments. They learned how to sequence the NWS based on lead time to achieve desired results as load progressively grows. They also learned how to monitor the progress of both the actual load and

[116] Coley Girouard, 'BQDM Program Demonstrates Benefits of Non-Traditional Utility Investments', *Utility Dive*, 2019 <https://www.utilitydive.com/news/bqdm-program-demonstrates-benefits-of-non-traditional-utility-investments/550110/> [accessed 18 August 2020].
[117] Girouard.
[118] REV Connect, 'Non-Wires Alternatives', 2019 <https://nyrevconnect.com/non-wires-alternatives/> [accessed 28 July 2020].

that impact of the NWS on a yearly basis (e.g. sometimes the load growth does not materialize as forecasted) and react as necessary.[119]

Progress on NWS and DER in Ontario

Ontario has some experience with NWS as well.

In 2013, Toronto Hydro began to assess "Local DR" (i.e. a precursor to the NWS terminology). As part of this process, Toronto Hydro developed a Local Demand Response Valuation and Financial Analysis Model to help explore the potential for localized DR initiatives that specifically target areas of high system constraint in Toronto's service territory. Toronto Hydro contemplated the potential for all types of NWS, including but not limited to DR, to defer such investments. In 2014, Toronto Hydro proposed to launch local DR initiatives downstream of the Cecil TS. The OEB approved the Cecil Local DR plan that was submitted to the OEB under Toronto Hydro's 2015-2019 distribution rates application submission of EB-2014-016. However, actual planning did not start until 2018. Toronto Hydro expanded the local DR proposal for the 2020-2024 distribution rates application submission, with continued focus on Cecil TS as well as additional transformer stations being targeted.

In 2016, the IESO launched the Market Renewal Program to make improvements to the current market design, leading to system efficiencies, lower costs for consumers, and new opportunities for market participants. The IESO's Market Renewal Program presents an opportunity to re-examine some of the structural barriers in place and facilitate improved coordination for a high-DER future. As emerging and existing actors start to have access to the market and as the number of services to maximize the value of DER are being re-evaluated, the scope and scale of market transactions will increase.

In 2019, the OEB started exploring the role of regulations in mitigating risks associated with higher levels of DER adoption in Ontario, and is supporting utilities in adapting to enable consumer benefit from DERs. The "Responding to DER" case (EB-2018-0288)[120] provides benchmarking and expertise in four main areas of investigation regarding DER integration within the Ontario market: enabling new services, enabling access to information, determining value of DER services, and clarifying roles and responsibilities. The consultation started on March 15, 2019, and is still underway. In coordination with the Responding to DER consultation, the OEB is also carrying out another parallel consultation effort on identifying pathways to utility remuneration such that they remain indifferent to traditional or innovative solutions and pursue least cost solutions while strengthening their focus on longer-term value and the impact of sector evolution in their system planning and operations.[121] This work is still underway.

The IESO is also currently undertaking an NWS pilot; the York Region NWS demonstration pilot (henceforth, the "York demo"). The pilot is seeking to leverage market constructs and test coordination aspects between the IESO and a distribution utility in securing and operating DER to meet anticipated local energy and capacity needs of the southern York region.

[119] Smart Electric Power Alliance, 'Non-Wires Alternatives: Case Studies from Leading U.S. Projects', 2020 <https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/> [accessed 24 July 2020].
[120] Ontario Energy Board, 'Responding to Distributed Energy Resources (DERs)'.
[121] Ontario Energy Board, *Utility Remuneration and Responding to Distributed Energy Resources Board File Numbers: EB-2018-0287 and EB-2018-0288*.

Additionally, the IESO is collaborating with other Ontario stakeholders to identify and overcome barriers that hinder DER from serving as NWS, not only for distribution but also for transmission and generation deferral opportunities[122].

While Ontario is pursuing similar goals to those in New York State and is working towards a better understanding of how to improve pathways for DER integration, the OEB and the IESO have yet have to establish a formal process by which NWS will be systematically considered by electric distribution companies in place of traditional capital infrastructure investments.

Electricity Grid Planning with DER and NWS

The planning of the electricity transmission system is already a process that is generally more public and more transparent by design than related planning on the natural gas side. That is due to the nature of the commodity – the electricity market requires close coordination all the way from the generator to the end-users because the supply needs to be balanced with the supply on an immediate basis.

In New York State, with a deregulated wholesale and regulated transmission and distribution, system planning is done by NYISO, and distribution planning is done by the electric utilities. The NYISO gives the distribution companies the top down forecast for their zones and distribution companies use that information as an input to their own forecasting and validation. They collaborate in determining which transformer station projects should be constructed. The PSC ultimately approves large infrastructure projects such as transmission infrastructure but utilities are participants in NYISO planning proceedings through stakeholder consultation processes.

Following REV, the PSC defined a set of functions of the modern utility or the Distributed System Platform, combining planning and operations with the enablement of markets. The PSC asked the New York State electric utilities to define and describe the implementation of these functions.

Formal NWS Process in New York State

New York State has embedded NWS as part of its distribution system planning process to create a formal process in which NWS are being considered on a routine basis. As per the formal distribution system planning process, once a list of system needs is compiled, utility planners identify all potential traditional and non-traditional solutions. NWS are particularly considered to meet growing demand when meeting the NWS suitability criteria over 10-years. The utilities developed NWS suitability criteria[123] to screen the potential projects and developed processes to source these resources.[124] The suitability criteria include consideration of project deployment timelines and cost effectiveness.[125] Once a utility identifies NWS, they are included in its Distribution System Implementation Plan.[126]

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[122] IESO, *Barriers to Implementing Non-Wires Alternatives in Regional Planning* <http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rpr/rprag-20181101-barriers.pdf?la=en> [accessed 31 July 2020].

[123] ICF, 'Idea of "Suitability Criteria" Paves the Way for NWA', 2018 <https://www.icf.com/insights/energy/suitability-criteria-nwa> [accessed 24 July 2020].

[124] Joint Utilities of New York, 'Utility-Specific Non-Wires Alternatives (NWA) Opportunities', 2020 <https://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities> [accessed 24 July 2020].

[125] ICF, 'Idea of "Suitability Criteria" Paves the Way for NWA'.

[126] In February 2015, the PSC required all distribution companies to identify at least one NWS project. NY Public Service Commission, *Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, 2015 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0B599D87-445B-4197-9815-24C27623A6A0%7D> [accessed 20 August 2020].

Electricity System Planning in Ontario

System planning in Ontario is performed in a highly collaborative fashion between the IESO and the distribution companies. Unlike in New York State, however, the process has not prioritized the same level of consideration of NWS. While NWS are considered frequently as part of stakeholder discussions, fewer NWS projects are implemented, and NWS are not being considered on a routine basis.

After the restructuring of Ontario Hydro in 2000, the (then) Ontario Power Authority (now IESO) initiated planning processes to address electricity supply adequacy and reliability needs through an engagement with distribution companies, transmitters, and other stakeholders. The IESO has identified 21 electric infrastructure boundaries across Ontario for regional electricity planning purposes. The process starts with a needs identification review cycle conducted every five years on each of these 21 boundaries to determine whether regional electricity planning is needed. Once it is determined that a revised or new regional electricity plan is needed, the IESO creates a schedule of additional studies before initiating an Integrated Regional Resource Plan (IRRP). An Integrated Regional Resource Plan is a mixture of conservation, generation, and wires considerations. Alternatively, the IESO can decide to pursue a Regional Infrastructure Plan, which strictly focuses on infrastructure.

In 2018, the IESO initiated the review of its regional planning process to consider the following:

- Potential barriers to implementing NWS,
- Opportunities for potential collaboration between bulk system planning, community energy planning, regional, planning,
- Developing a coordinated, cost-effective, long term approach to replacing transmission assets at the end of their life

One focus area recommendation that came out of this review process was to consider NWS more frequently to manage load growth and address regional electricity needs. Only a few NWS projects have been planned or implemented so far – this includes Toronto Hydro's Cecil TS local DR project and the IESO/Alectra's York Region NWS project.

4.5 Modernization of the Long-Term Gas Capacity Planning Process in New York State

Undertaking a large infrastructure project in New York State tends to require 5 to 8 years of planning, permitting, engineering and construction work. An example that demonstrates this timeline is the National Grid Long-Term Capacity Planning Table 29.[127] Most of the costs for these projects occur during the final planning and construction phases in the last 3 years. As a result, stopping a project when it is past this three-year mark can result in significant sunk costs.

To date, New York State gas utilities have performed supply and distribution system planning as one key task leading to their rate filing. While the results of the planning have been discussed and substantiated in front of the PSC and intervenors on a confidential basis, the planning was rarely published in a dedicated report, nor was it discussed with stakeholders (beyond intervenors) through formal stakeholder consultations. The gas utility planning processes have been kept confidential due to potential competition and security related issues. The utilities believe that obtaining the least costly supply portfolio on behalf of customers may require withholding certain types of information from public view.

[127] National Grid, *Natural Gas Long-Term Capacity Supplemental Report for Brooklyn, Queens, Staten Island and Long Island*.

This is somewhat different from the planning processes for electric utilities. In part, the differences in the planning processes for electricity and natural gas reflect differences in the regulatory structure of their primary suppliers. For instance, interstate pipelines are not the object of long-term public planning to the same extent that power wholesale markets and transmission network are. The gas utilities must negotiate for capacity directly with pipeline operators and developers.

There are two fundamental differences between electricity system planning and gas system planning. Firstly, gas can be stored – seasonal natural gas storage has been extensively used since the early days of gas extraction. Gas can be stored in caverns, as CNG or LNG at distributed or centralized facilities, or even by increasing the level of compression in the transmission and distribution pipes. To a degree, the storability of gas has suppressed the need for planning integration between the transmission and distribution systems.

Secondly, electric systems are designed with an acceptable level of system outage risk, while gas systems are designed with a higher degree of reliability. The gas industry has a lower risk tolerance for outages because of the increased costs to restart systems should outages occur,[128] let alone the hardship that would be imposed on customers in the middle of winter if they were to lack space heating for more than perhaps a few hours.[129] This is fundamentally different from the planning principles used by electric utilities, which are essentially planned with the expectation of at least some individual facility failures. As such, the need for reliability of the solution is paramount and this need has forced natural gas utilities to carefully consider innovations respective to novel demand-side solutions not only in New York State, but also in Ontario and elsewhere.

In the wake of the several recent moratoria that have caused hardship on customers in New York State, the PSC has undertaken a proceeding that is intended to lead to better long-term planning practices in the state. Public concerns regarding the moratoria as well as recognition for the need for new processes that align with New York State's climate policy, including the CLCPA, led the PSC to initiate a proceeding on March 19, 2020 to update planning procedures for natural gas utilities in the state.[130]

The order initiating this planning proceeding addressed the risks incurred by gas utilities due to over-reliance on short-term peaking contracts on existing interstate pipelines. The terms of these contracts can be short, they cannot necessarily be relied upon for following years, and they are tied to market prices, which can be expensive.

Other types of peaking services include delivered CNG or LNG, which are also expensive. In addition, utilities are concerned that trucks may not reach their destinations on time because of road congestion in Downstate New York, which they exacerbate. The PSC wrote: "*Reliance on delivered services for a high percentage of a utility's peak load presents significant risks.*" (…)

[128] Safely relighting a section of the distribution system requires a series of time-consuming steps, including: (a) Turning off service valves at every customer meter in the affected area; (b) Correcting the underlying issue that created the loss of system pressure; (c) Reintroducing gas into the affected mains and services; (d) Purging the affected mains and services to ensure that the pipes are filled with 100% natural gas; and (e) Unlocking customer meters and relighting customer appliance pilot lights on a customer by customer basis.
[129] Which may activate emergency actions, for instance, like distributing and installing portable electric heater, and/or moving people into warming centres. A large scale relight could take weeks rather than days or hours to resolve.
[130] NY Public Service Commission, *CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*.

and "*Given the pivotal role of peaking services in moratorium decisions, clear criteria must be developed.*"[131]

To date, New York State utilities have considered NPS on an ad-hoc basis, when utilities have raised concerns about their ability to reliably meet growing customer peak demand without additional infrastructure investments or suitable NPS. This approach has led to a situation where some NPS pilot programs were initiated and some proposed NPS measures were rejected. The proceeding is meant to suggest a path forward so that NPS are considered more consistently.

The PSC has also highlighted the importance of criteria air pollutant reduction. The PSC referred to gas DR programs or interruptible rates that have customers rely on oil or propane combustion to make up for lack of firm gas service, introducing "clean (gas) demand response" as a new concept. According to the PSC:

> "*Other methods of demand response and peak reduction must be developed, to respond to the increasing need, to transition away from methods that rely on oil combustion, and to enhance solutions that may be used to avoid infrastructure investment.*"[132]

While this proceeding is broader than just NPS, it is addressing updated procedures to integrate NPS into gas utility planning processes, both for specific projects that may be avoidable within specific parts of the distribution system (i.e. "locational constraint analysis") and in terms of overall reductions to system-wide demand and the associated need for infrastructure investments.

The proceeding entails the following steps: (1) 90-day filing for gas utilities to report on a supply and demand analysis for vulnerable distribution systems on their network; (2) 120-day filing for gas utilities to complete a supply-and-demand analysis of their entire service territory; and (3) 120-day filing for gas utilities to suggest a criteria for reliance on peaking services and an approach to moratorium management. On October 19,[133] the Department of Public Service Staff is scheduled to issue a proposal to modernize the gas system planning process.

Gas System Planning in Ontario

In Ontario, facility investment plans consider a multi-year forecast of system growth, as well as known replacements and relocations. The asset management plans are reviewed periodically and are updated as needed to reflect changes in the forecast, reflecting any changes in the anticipated growth rates. A typical facility investment plan begins by identifying the expected need for additional capacity about five years prior to the time that the capacity is likely to be required. Between three and five years, the forecasts of demand growth are refined, capital budgets are developed, and small initial investments are made for engineering, environmental assessments, and design. The effort culminates with the gas utility submitting for leave to construct. Similar to New York State, it is only during the last three years, in parallel with and after the leave to construct process, that significant expenses are incurred. Construction typically occurs in the last 12 to 18 months.

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[131] PSC, *CASE 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, 2020.
[132] PSC.
[133] At the request of DPS Staff, the original 150-day deadline of August 17, 2020 was first extended to August 31, 2020, then extended again until September 21, 2020, and then again extended to October 18, 2020.

4.6 Current Status and Results from NPS Projects in New York

ICF's research and discussions with the gas utilities in New York State indicated that gas utilities in the state are using distributed CNG. They have legacy LNG facilities and are adding more LNG facilities to provide peaking solutions. They have also implemented a limited number of EE, gas DR, and electrification pilot projects and are considering additional pilot projects.

A summary of NPS projects and programs in New York State is provided in Exhibit 15. While there have only been a limited number of NPS projects in the state, they have generated useful results and discussion that is laying the groundwork for a more widespread use of such solutions.

Exhibit 15 Summary of NPS Projects and Programs in New York State

Utility	NPS Projects and Programs
ConEdison	• Currently uses CNG injection for peaking capacity on constrained parts of its system, and has expressed the need to plan for more. ConEdison uses CNG injection to alleviate a daily peak constraint at its city gates and to address hourly constraints on specific branches of its distribution system. • Their Residential Gas DR Pilot leverages the fleet of thermostats from ConEdison's electric direct load control program, and from a separate bring-your-own-thermostat offering. Results have been published (see page 22 of this report). • Offer performance-based gas DR for the Commercial & Industrial (C&I) and Multi-unit residential buildings. Results have been published (see page 22 of this report). • As a result of a 2017 public solicitation for NPS, the following pilot projects were deployed over a one-year period: o Residential gas-to-ground-source heat pump electrification pilot project in Westchester County. Published results are pending. o Residential weatherization program. Published results are pending. o Multifamily building gas-to-air-source heat pump pilot project in the Bronx, which failed due to the withdrawal of interest from a participating building. • Recently issued a new request for information to solicit the market for additional pilot projects.
National Grid	• Currently uses CNG injection for peaking capacity, has expressed a need to plan for more, and is considering a number of LNG facilities and smaller infrastructure options (e.g. compression projects, a shorter transmission pipeline project to connect existing interstate pipelines) to meet developing constraints on its system. • Their C&I gas DR pilot program (with 16 buildings) is being transitioned to full scale deployment, and will replace temperature-controlled customers rates. Most participants in the program need a back-up source of heat from a secondary fuel such as heating oil or propane. PSC's encouragement of "clean (gas) DR" (i.e. curtailment of gas service without the use of petroleum products as a back-up fuel) may present a challenge for the program. • Currently exploring two RNG plants. • Studying Power-to-Gas hydrogen insertion into its network. • Planning a residential and small business bring-your-own-thermostat gas DR pilot program, and a small and medium business behavioral program.
Central Hudson	• Pioneered the use of beneficial electrification (gas-to-heat pumps – either ground- or air-source heat pumps) to avoid costly replacements of leak-prone cast iron and

Utility	NPS Projects and Programs
	bare steel pipes in its distribution system. Refer to this approach as a “transportation mode alternative”. • Planning to implement an incentive kicker to promote the adoption of advanced thermostats for customers in high constraint areas in advance of the 2020/21 heating season. The incentive kicker would be substantially higher than the existing incentive (e.g. 2-4 times higher). No additional approvals are required for this program.

5. NPS Benefit Cost Analysis

One of the challenges associated with the evaluation of NPS alternatives has been the development of a consistent approach to the Benefit-Cost Analysis (BCA)[134] needed to compare different types of NPS. ConEdison uses the BCA Handbook for Non-Pipeline Solutions[135] to perform economic assessment of NPS including distributed storage, RNG, broad-based or geo-targeted EE and gas DR, and electrification. To ICF's knowledge, ConEdison's draft BCA Handbook for NPS is the most comprehensive BCA Framework available for NPS economic evaluation in North America.

ConEdison has proposed an updated version of the Handbook as part of its NPA Framework to align with the latest direction provided by the PSC (i.e. integrating NPS into the regular long-term capacity planning process). The proposed update has not yet been reviewed or approved by the PSC. This section provides an account of the current Handbook, its contents, the associated implications, and insights into the upcoming updates.

In January 2016, the PSC required gas and electric utilities to develop a BCA framework for NWS.[136] According to the PSC, BCA for NWS should be compliant with five foundational principles:

> "*1) be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular; 2) avoid combining or conflating different benefits and costs; 3) assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures); 4) address the full lifetime of the investment while reflecting sensitivities on key assumptions; and, 5) compare benefits and costs to traditional alternatives instead of valuing them in isolation.*"

Furthermore, the BCA for NWS Order selected the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure cost test (RIM) as its primary cost-effectiveness indicators.[137]

In August 2016, the JU responded to the PSC's order with Standard BCA handbooks (essentially one handbook for each electric utility) that were meant to flesh out the methodological approaches underlined by the BCA Order. The handbooks were similar, except for variations on territory-specific sources and assumptions used for cashflow analysis.

The BCA handbooks from the electric utilities in New York State are largely in alignment with fundamental principles laid out in the California Standard Practice Manual,[138] and the more recent National Standard Practice Manual (NSPM).[139] ConEdison's BCA Handbook for NWS preceded the new NSPM for DERs, which was released in August 2020 and is also in alignment with the new handbook.[140]The NSPM for DER is a sign that there is a set of best practices that

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[134] To be clear, BCA is equivalent to what would be referred to cost-effectiveness testing in Ontario. We will use BCA in this report, but BCA evaluation could be used interchangeably with cost-effectiveness evaluation.

[135] NY Public Service Commission, *Order Establishing the Benefit Cost Analysis Framework*.

[136] NY Public Service Commission, *Order Establishing the Benefit Cost Analysis Framework*.

[137] NY Public Service Commission, *Order Establishing the Benefit Cost Analysis Framework*.

[138] CPUC, *California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects*, *California Public Utilities Commission* (California, United States of America, 2001) <https://doi.org/10.1016/B978-1-85617-804-4.00018-5>.

[139] National Efficiency Screening Project, *The National Standard Practice Manual*, 2017.

have started to crystallize around DER and NWS in the electricity sector in North America. The same cannot be said about NPS.

In late 2017, ConEdison issued a public tender for NPS from various proponents that would provide peak-day relief in key areas. During the effort leading up to the solicitation, ConEdison developed the first version of its BCA Handbook for NPS. ConEdison largely took its BCA Handbook for NWS as a point of reference for the development of the BCA Handbook for NPS. The first version was presented to the PSC and was used to assess the cost-effectiveness of the responses to the solicitation. The latest version of the BCA Handbook for NPS was issued in March 2018.[141]

Prominent features of the included costs and benefits that are relevant to any discussions of a similar framework in Ontario are listed below:

- The avoided costs of upstream supply and distribution system capacity (i.e. both sides of city gate) are kept separate.
- The benefits (and costs) values can be “stacked” upstream and downstream of city gates (i.e. multiple value streams). In other words, both the avoided cost of distribution capacity and the upstream avoided cost (capacity, commodity) must be considered.
- Costs and benefits are accrued or incurred as they impact revenue requirements. Commodity and operational costs are avoided in the same year that they occur. Capacity and infrastructure benefits (or costs) are also assumed to occur in the same year that they are realized. For instance, if a project reduces system peak demand in 2020 but the portfolio of upstream assets cannot be modified in 2020 to account for the reduction, any benefits should still be accounted for within that year. As such, impacts can only be realized if NPS impacts are known far enough ahead of time to make the necessary adjustment to any associated capacity portfolio planning.[142]
- Only “avoidable” losses need to be incorporated into the calculations when assessing the avoided cost of upstream supply and distribution costs. “Losses” (often known as the “lost and unaccounted for” percentage) represent the difference between total energy send-out and the total energy metered at each facility. Losses related to leakage and inaccurately measured customer revenue meters is not directly avoidable. The avoidable losses are a smaller percentage as compared to the regular losses.
- Similarly, “avoided distribution operations and maintenance (O&M)” is concerned only with variable O&M benefits since O&M costs will be affected by the NPS. For instance, they could include an appropriate allocation of administrative and common costs associated with an “avoidable” project.
- In addition to the use of a coincidence factor between the nameplate capacity of an NPS and its coincidence with the peak at city gate (or the peak on the distribution system), the Handbook proposes a Derate Factor. The Derate Factor is used to derate the coincident peak demand benefit based on its expected availability during peak events. The Derate Factor is a combination of the number of days an NPS can be available during a given heating season and an assessment of performance risk (i.e. the reliability of the NPS compared with the traditional, supply-side equivalent).
- CO_2 emissions are converted into an external benefit using the social cost of carbon as per the US EPA.[143] Avoided CO_2 emissions are part of the societal benefit used to determine the performance incentives for NWS (the performance incentive is defined as a percentage of

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[141] ConEdison, *Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions (New York, NY, USA, 2018)*.
[142] The BCA Handbook did not specify how long that is.
[143] U.S. Environmental Protection Agency (USEPA).

the net benefit). If the PSC was to agree to the same formula to determine the utility performance incentive for NPS, it would mean that the gas utility incentives to implement NPS in New York State would increase with higher valuations of carbon emissions. The higher the valuation of carbon emissions, the higher net societal benefits, the higher the utility incentive.

- The Handbook includes limited details regarding the handling of reliability/resiliency, non-energy benefits (or costs), and other externalities (benefits or costs). The Handbook suggest that "t*o the degree these benefits exist but are not readily quantifiable, their impacts may be qualitatively assessed*." Consequently, the valuation of carbon emissions based on the social cost of carbon appears to be the main quantified distinction between the SCT and the total resource cost test as it applies to NPS in New York State at this time.

In addition, ConEdison's BCA Handbook for NPS indicates that gas utilities like ConEdison have a variety of options to procure supply capacity in the short, medium, and long run as the utilities negotiate with many operators of interstate pipelines delivering to their city gates and developers interested in building new pipelines. As such, it is challenging to develop a simple annualized cost of capacity (e.g. $ per MMBtu/d-year) without a better understanding of the overall demand scenario when accounting for the whole portfolio of NPS. For instance, if a portfolio could effectively meet a certain threshold of NPS capacity, then a new pipeline could be avoided altogether, yielding savings for ratepayers. Anything below that threshold indicates that a pipeline is still needed, and the avoided cost serves as the market price of short-term capacity contracts with interstate pipeline operators.

Furthermore, different supply options yield different variable costs. For instance, a new pipeline can provide access to new upstream suppliers, perhaps with lower commodity prices. The foregone savings that would have resulted from gaining access to cheaper suppliers should offset the avoided cost of the new pipeline.

While the utilities are responsible for seeking the lowest cost reliable supply portfolio on behalf of their customers, much of the supply planning and portfolio planning information provided by the New York State gas distributions to the PSC is provided on a confidential basis. As such, key information related to estimating upstream gas supply costs has not been as readily available as electricity wholesale and transmission costs and the supply planning for gas at city gates is not as transparent and integrated as the supply planning at the transmission-distribution nodes of a power market.

In addition, the proceeding that started on March 19, 2020 has been more focused on their distribution system constraints. This suggests that there may be an increased focus on the avoided cost of distribution infrastructure as opposed to upstream supply at city gate going forward.

Comparison with Ontario Cost-effectiveness Testing Practices

In Ontario, Enbridge is required to employ an enhanced total resource cost (TRC) test to assess the cost-effectiveness of its DSM programs. This cost-effectiveness test, which is referred to as the TRC-plus, incorporates a 15% adder to the avoided costs to account for non-energy benefits. Enbridge assesses the TRC-plus of gas DSM measures when it develops its DSM program offerings. Although the TRC-plus is the primary test to assess the cost-effectiveness of its DSM programs, Enbridge has also been directed to use the PAC (also known as UCT) as a secondary reference tool to help prioritize programs and deliver the most cost-effective results. Enbridge and the OEB are also very familiar with the other tests that are outlined in the California Standard Practice Manual, such as SCT and RIM test.

The TRC-plus used in Ontario is not very different from the SCT suggested by ConEdison since the SCT is also unspecific regarding the treatment of non-energy benefits and externalities – allowing them to be assessed qualitatively rather than quantitatively. The main difference between Enbridge's TRC-plus and ConEdison's SCT is that the value used to assess the avoided cost of pipeline capacity in Ontario is an average figure that is blended into the $/m^3. Conversely, ConEdison is suggesting to: (1) Separate the capacity cost (m^3 per day) from the commodity cost (m^3); (2) De-average the capacity cost and make it specific to the demand constrained area;[144] and (3) Separate upstream capacity costs (i.e. before city gates) from distribution capacity costs (i.e. downstream of city gates).

Since NWS and NPS programs are expected to generate value to ratepayers by deferring or avoiding large capital expenditures, and in turn applying a downward pressure on rates, the RIM test is more relevant to both NWS and NPS than it is to gas DSM. As such, the RIM is expected to become a more meaningful indicator for NPS programs.

[144] In return, areas of low constraint would be expected to have a lower avoided capacity cost.

6. ConEdison's Proposed NPA Framework

On January 16, 2020, the PSC released the "Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan" for Case 19-G-0066 and Case 19-E-0065. This order approved the terms of the Joint Proposal, and ConEdison was required to file a response. ConEdison's proposal was filed with the PSC on September 15, 2020.[145] It indicated that:

> *"This NPA Framework Proposal describes the Company's process for identifying, developing, implementing, and recovering costs and establishing performance incentives for NPA projects that would defer or eliminate traditional natural gas distribution infrastructure projects."* [146]

While the proposed Framework has not been approved by the PSC, it reflects a further advancement in the status of NPS. However, it remains an interim step:

> *"While this filing represents a step forward, it is the beginning, and not the end, of the Company's efforts in this area. In line with its experience in implementing NWS, the Company anticipates learning many lessons as early NPA are implemented. As such, the Company anticipates evaluating, modifying, and potentially expanding its approach to NPA in the coming years, in line with its commitment to deliver a clean energy future for its customers."*[147]

We have summarized the salient aspects of the proposed Framework here. The new Framework also includes an updated version of the BCA Handbook, that will supersede (but not necessarily contradict) the earlier version of the BCA Handbook reviewed in Section 5 if approved. We have briefly summarized the refinements in the proposed BCA Handbook as well.

6.1 Role of Decarbonization Policy and NPS for ConEdison

ConEdison developed the NPA Framework in close collaboration with the Staff of the Department of Public Services. ConEdison begins the Framework by confirming its support of the CLCPA objectives, and establishing a connection between the Framework and the PSC's Gas Planning Proceeding, discussed in Section 4.7.

In the conclusion of the 90-day filing for the PSC's Gas Planning Proceeding, ConEdison wrote:

> *"New York State is on the path to a clean energy future. The use of natural gas in the service territories of both ConEdison and Orange and Rockland is in transition (…) It is expected that natural gas will continue to be the preferred choice for customers in the near term, causing continued peak demand growth, before a plateau and downturn occurs as they move to greener solutions to meet their needs. Uncertainty exists around when that turning point will occur."*[148]

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[145] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*, 2020 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2CCB0D2A-183A-483B-9F56-87878E0471FA%7D>.

[146] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

[147] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

[148] ConEdison, *Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures – Supply/Demand Analysis for Vulnerable Locations*.

However, safe, reliable and affordable service is critical and can only be achieved through an appropriate supply-demand balance throughout the entire transition period. In the NPA Framework, ConEdison wrote:

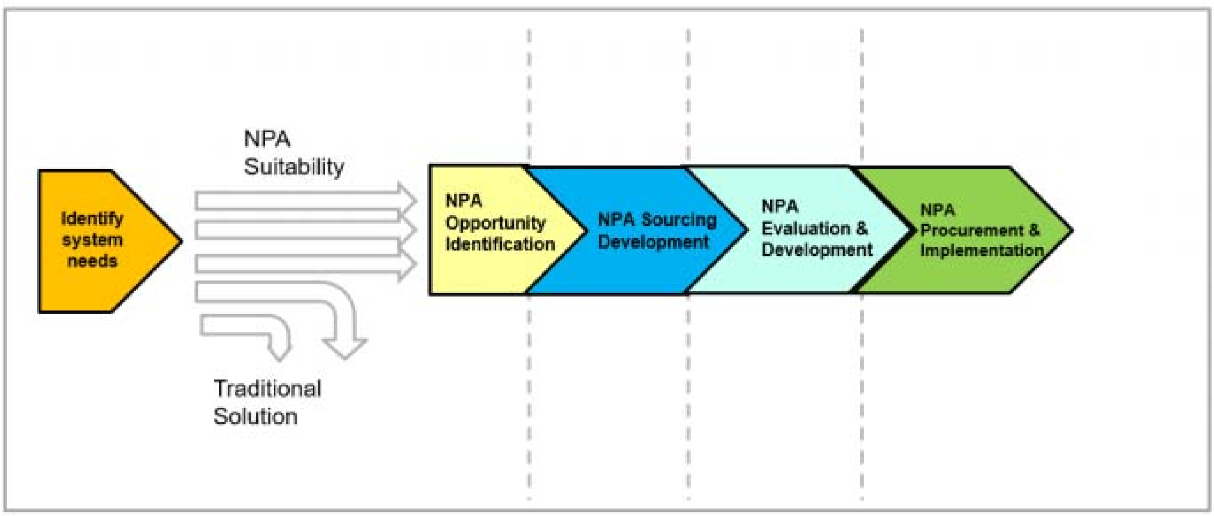
> *"Maintaining the safety and reliability of the natural gas system remains critical to considerations of how alternatives to traditional infrastructure maintenance can be applied, but this does not mean that NPA cannot be evaluated or tested for any of these projects. Instead, under this Framework, the Company proposes to evaluate planned safety- and reliability-related infrastructure projects (e.g. planned future work under its Main Replacement Program) for replacement using an NPA and attempts to shed light on the many unanswered questions in this uncharted territory."*[149]

While ConEdison has committed to consider the full array of solutions, including both NPA and traditional safety- and reliability-related infrastructure projects, there is a recognition of the many unanswered questions related with NPS. ConEdison thereby proposes a high-level process that will remain consistent over time, but where aspects of NPS assessment, planning and implementation will change over time as more is learned about NPS.

6.2 NPS Process Overview

The standard process proposed by ConEdison is presented in Exhibit 16.

Exhibit 16 NPS/NPA Process Overview



ConEdison identifies needs through its planning process. It assesses on an annual basis the current and forecasted operating condition, including localized peak day demand. The utility continually makes course-corrections to its annual plan as necessary due to emergent conditions (e.g. accidental leaks, road paving announcement by municipalities). ConEdison's system engineers regularly assess various options to address system needs based on the relative effectiveness of the options and their associated costs, timing, and risks.

ConEdison is proposing to integrate NPS as a set of options integrated into its annual and continuous planning process. The utility is proposing to commence work related to NPS one or more years before work on a traditional project is scheduled to start.

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[149] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

The types of investments that ConEdison is suggesting are suitable to be substituted by NPS include the following three categories of traditional investments:

1. **Load Relief Upgrade:** Areas where the gas main ought to be replaced by a larger pipe due to demand growth to support continued reliability.
2. **Regulator Station Upgrade:** Areas where the pressure regulator station ought to be upgraded due to demand growth to support continued reliability.
3. **Main Replacement:** The Main Replacement Program is meant to replace leak-prone gas mains (i.e. wrought iron and unprotected steel pipes). The prioritization of the pipe replacements is based on a number of factors. When considering a replacement of a pipe segment, and provided all customers are willing to adopt an alternate fuel, ConEdison would consider retiring the pipe segment instead of replacing it. However, this would represent a significant challenge since all of the customers that are being served by the segment would have to voluntarily agree to a conversion.

Certain types of expenditures are deemed unsuitable to begin with, like non-distribution infrastructure (e.g. IT or AMI systems), emergency safety expenditures, and expenditures to meet health and safety regulatory requirements.

The suitability criteria not only assess the relevance and cost-effectiveness of NPS against traditional solutions, but also the NPS sourcing approach. ConEdison wrote:

> *"The Company proposes to tailor NPA approaches based on project characteristics – favoring streamlined alternatives, such as expanding energy efficiency programs in a targeted footprint for smaller, shorter-term projects (e.g., main work needed in 18 months impacting two or fewer streets in a neighborhood) and soliciting innovative solutions from the market when there is a project with sufficient scale and adequate lead-time for a solicitation (e.g., regulator station project needed in 36 months to supply gas to a large area)."*[150]

In the proposed NPS Framework, the procurement of NPS is generally designed to align with REV principles related to tapping the resources and the creativity of the competitive market to develop programs in the best interest of ConEdison customers. The Framework also differentiates the approach to NPS based on time and scale factors. The practicalities of issuing a solicitation for short-term (i.e. less than 36 months yet more than 18 months) or small projects (i.e. less than $2m USD) can be challenging. ConEdison proposes to deal with short-term or small projects by leveraging existing EE programs rather than soliciting the market through a request for information or a request for proposal.

In the Framework, ConEdison stresses the need for flexibility, monitoring, and short reaction time:

> *Planned work on the utility- or customer side can evolve, measures that were expected to be installed can be delayed, accelerated or cancelled, and forecasted demands can shift. (…) The Company's goal is for a portfolio that can meet load relief needs in a timely manner and thus mimic traditional solutions' level of reliability; or, in cases where load relief needs cannot be met, to allow for sufficient time for an alternate traditional solution to be implemented to maintain system reliability.*[151]

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[150] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.
[151] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

ConEdison recognizes that it can go both ways. The actual load growth can differ from the forecast, or the NPS portfolio performance can differ from expectations. In both cases, the Framework envisions the need to take quick measures to protect reliability (e.g. undertake traditional upgrade), and promote affordability (e.g. ramp down NPS if not required anymore).

Following the assessment of the suitability of traditional investments to be substituted by an NPS, NPS measures and program will be assessed through a list of qualitative and quantitative criteria including: costs; executions risks; coincidence with peak; vendor qualifications; availability and reliability; state policy/community impacts; customer acquisitions; timeliness; and BCA.

6.3 Proposed Update to the ConEdison Benefit-Cost Analysis Handbook

The proposed Framework includes an updated version of the 2018 Draft BCA Handbook for NPS, the “ConEdison Benefit-Cost Analysis Handbook”. If approved, this proposal will refine the existing BCA Handbook without making fundamental changes to its approach. The main decision test for NPS investments remains the SCT, and it is also the SCT (i.e. the net benefit under the SCT) that is proposed to be used to calculate the utility performance incentives related to NPS investments.

Prominent changes in the new proposed Handbook include:

- The adoption of “On-system Avoided Cost” and “Off-system Avoided Costs” in place of “Upstream Avoided Cost” and “Downstream Avoided Cost” to describe cost impact before and after city gates. The change is largely semantic but reflects the fact that ConEdison does have transmission pipelines within the limits of its system. The change will avoid confusion.
- The Handbook is more specific on the applicability of the avoided cost of ConEdison’s infrastructure or “On-system capacity”. Avoided On-system capacity costs can include avoided cost of on-system transmission, gas pressure regulators and distribution pipes. The avoided or deferred cost must include the entire carrying charge (i.e. depreciation, cost of capital, taxes, and even incremental O&M).
- The introduction of the weighted average cost of peaking services which is a necessary adjustment to the value of the avoided cost of certain NPS that are not available for the full duration of the system peak.
- A change to the treatment of avoidable company retained gas (the new “avoidable” losses) to reflect differences depending on where the NPS measure is located. For instance, the avoidable company retained gas is higher for a behind-the meter measures than it is for measures located upstream on ConEdison’s system.
- The Off-system Avoided Cost of capacity requirements are divided into Peaking Services and Pipeline and Storage Costs. Furthermore:
  - The avoided cost of peaking services needs to be netted from reservation fees, which must be incurred whether the actual peaking capacity will be needed or not.
  - Peaking services are delayed by one year, as the avoided peaking services will only be accrued one year after gas demand offset is achieved.

Because peaking services are avoidable or deferrable, the price of peaking services is the best proxy for market equilibrium price of capacity. The price of peaking service is high, as reflected in the high retail cost of gas in Downstate New York.

The economic rent between the proxy equilibrium price (i.e. peaking services) and the NPS costs is substantial compared with Ontario because of how much higher the price is in New

York State, which makes the potential share of economic rent for the utility, NPS suppliers, participating customers, and ratepayers more substantial in New York State than in Ontario.

6.4 NPS Utility Accounting and Performance Incentives

As part of the approval of the ConEdison Joint Proposal in January, 2020, the New York State PSC approved in principle a general structure for the recovery of NPS costs for ConEdison.

> *"The Joint Proposal also continues the Company's electric Non-Wires Alternative (NWA) adjustment mechanism and introduces a similar Non-Pipelines Alternative (NPA) adjustment mechanism for gas. Under the new NPA mechanism, the difference in costs between an NPA implemented during the term of the Proposal and costs in rates associated with the displaced project, including the overall pre-tax rate return on such costs, will be recovered as a regulatory asset through Con Edison's Monthly Rate Adjustment (MRA) clause. Unamortized NPA costs, including the return, will be incorporated into the Company's base rates when gas base delivery rates are reset. These provisions are included to provide an incentive to the Company to pursue cost-effective alternatives to traditional electric CASES 19-E-0065 and 19-G-0066 and gas infrastructure investment in furtherance of Commission policy."*

The NPS Framework filed in September provides a more detailed proposal for NPA cost recovery and performance incentives:

> "*As provided in the Gas Rate Plan, the Company's costs for NPA implementation, including the overall pre-tax rate of return on such costs, will be recovered as a regulatory asset. The Company is proposing an amortization period of 20 years because this generally aligns with the projected useful life of the measures that are expected to be installed and appropriately spreads out costs for customers. A single amortization period for the NPA portfolio also provides administrative and accounting consistency and simplicity. The Company proposes recovery of NPA costs and any applicable incentives during this Gas Rate Plan through the MRA. The Company shall file to incorporate unamortized NPA costs, including the return, into the Company's base rates when gas base delivery rates are next reset."* [152]

ConEdison is proposing to amortize NPS costs over 20 years at its weighted average cost of capital including its regulated return on equity. Initially the amortized costs will be collected through a rate rider, the MRA. During the next rate case the unamortized costs, including cost of capital, will be included in the rate base. Throughout the 20 year amortization period, the NPS investments would be generating a net income that is commensurate with a traditional infrastructure project of the same cost.

The proposed framework also includes an incentive structure, similar to the incentive proposals that have previously been rejected by the PSC:

> *"In line with New York's treatment of NWS, the Company also proposes a performance incentive equivalent to 30 percent of the net benefits of a project, as determined by the BCA. The Company also proposes to maintain the general structure applicable to NWS with respect to the calculation of performance incentives as changes to specific*

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[152] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

> *programs occur, including savings sharing mechanisms, such that the Company is incented to reduce costs from forecasted amounts while an NPA project is in-flight."* [153]

The incentive proposal is structured with a bi-directional floor and cap to mitigate risks for both ConEdison and ratepayers.

[153] ConEdison, *Proposal For Use Of A Framework To Pursue Non-Pipeline Alternatives to Defer Or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution Infrastructure. Case 19-G-0066*.

7. Conclusions

In this report, ICF presents a review of NPS and capacity IRP practices in a number of jurisdictions, with a particular focus on regions with relevant NPS activity. ICF's research represents a targeted effort to update the jurisdictional review completed as part of the Enbridge 2018 IRP Study. With the exception of utilities in New York State, ICF identified limited recent progress with regards to gas utilities using EE, gas DR, and electrification to eliminate or defer gas infrastructure projects. As a result of the recent progress in New York State with respect to NPS, a significant portion of this report is focused on comparing Ontario and New York State, explaining key differences between their gas and electricity markets, and highlighting the most important implications on system planning processes and the relevance of NPS.

The primary conclusions from this review include:

1) ***Overall, ICF found little progress on implementation of NPS, including development of geo-targeted EE, gas DR, and targeted gas-to-electricity conversion efforts in North America outside of New York State since the 2018 ICF study was completed.***
2) ***In New York State, ICF found that the utilities have made relevant progress in the development of NPS in terms of long-term capacity planning and analysis (e.g. National Grid Long-Term Capacity Planning reports) and pilot projects (ConEdison's gas DR pilot projects).***
3) ***Recent and upcoming progress on NPS in New York State promises to provide guidance on how to tackle many of the challenges associated with implementation of NPS, including treatment of issues related to utility remuneration and return on investment for different types of NPS.***
4) ***Ontario differs from New York State on many of the aspects that determine the value of NPS. Despite these differences, the experience in New York State represents a valuable source of information and best practices regarding NPS for Ontario utilities.***
    a. ***These differences include fundamentally higher energy costs in New York State, which tend to improve the economics of NPS options in the State. Demand in New York State also tends to be peakier than in Ontario, which increases the costs of conventional pipeline capacity relative to NPS options. Both factors improve the economics of NPS options in New York relative to Ontario.***
    b. ***The differences between Ontario and New York also include fundamental differences in the availability of natural gas pipeline capacity, the lower cost of infrastructure development in Ontario, the integration between the power and natural gas industries, both from a corporate and a regulatory perspective, and the nature of the natural gas load. These differences impact the need for and relevance of NPS in the two jurisdictions, and also explain the differences in NPS development timelines.***

ICF's analysis outlines key market structures, such as gas and electricity wholesale/ transmission infrastructure and distribution entities. We also compare and contrast processes surrounding resource procurements, key supporting actors (e.g. NYSERDA, the Joint Utilities), and relevant policies (e.g. New Efficiency New York and CLCPA). In addition, our research provides a high-level overview of DER policies in New York State and Ontario, and discusses how this has impacted the development of policies and frameworks related to NWS. In particular, ICF investigated how circumstances in New York State over the past five years have created a fertile ground to the proliferation of NPS projects and programs.

However, while ICF identified a significant number of relevant NPS pilot projects in New York State, to date, few of them have yielded published results, let alone been deployed on a full-scale basis. One exception to this is National Grid's C&I gas DR program, which is substituting for its interruptible and temperature-controlled rates. However, National Grid's C&I gas DR program requires participants to have a delivered-fuel back-up heating system (i.e. fueled by either propane or heating oil). In its March 2020 order, the PSC noted that it is considering encouraging "clear gas DR" programs rather than DR programs that rely on pollutant-emitting combustibles.

As per the latest PSC order, New York State is also on the brink of renewing its approach to long-term gas capacity planning in alignment with the CLCPA and New Efficiency New York. The updated approach may include routine consideration of NPS to address both city gate and distribution system-level constraints.

Drivers for Non-Pipe Solutions in New York

There are many drivers in New York State that laid the ground for this new order from the PSC. This includes alignment with clear top-down state government policies, strong load growth, constraints on the development of large infrastructure that is outside of the purview of the PSC and the utilities, the peakiness of incremental natural gas load in parts of New York State, the high cost of infrastructure development in densely occupied areas (particularly in Downstate New York), public concerns and focus due to the proliferation of moratoria and cancelation of natural gas pipeline projects, as well as precedent with the REV and NWS in the electricity sector.

ConEdison filed an early NPS plan for approval by the PSC but the PSC and stakeholders have been reluctant to authorize certain innovative NPS programs or budgets for NPS, preferring that New York State utilities leverage existing broad-based DSM and broad-based heat pump program budgets instead. As a result, the utilities are expected to employ a portion of their regular broad-based DSM budgets, which were substantially increased due to the Accelerated EE Order, to address peak demand constraints.

Of particular note, while electric and gas utilities are rewarded for pursuing broad-based DSM through a performance incentive (i.e. the earnings adjustment mechanism) and electric utilities have been able to claim a performance incentive for NWS through a 50/50 benefit split scheme, The New York State PSC has agreed in principle to grant similar performance incentive mechanism for NPS in that it is defined as a percentage of the net benefit using the SCT.

The lack of a performance incentive mechanism could potentially hinder the development of NPS due to the foregone earnings from not pursuing traditional infrastructure solutions. However, progress is anticipated on this point in the near future given ConEdison's recent proposal requesting performance incentives for NPS similar to those that are available for NWS.

Challenges Found in Other Jurisdictions – and Possible Solutions

As part of the 2018 IRP Study, ICF identified a consistent set of challenges that needed to be addressed before NPS could reliably and effectively be considered as an alternative to infrastructure planning. ICF discussed progress with addressing these challenges during our consultations with utilities from June-August 2020 and found that most of the utilities reviewed had not made material progress on addressing these concerns.

Exhibit 17 Perspective on the Challenges to NPS from 2020

<table>
<tr><th colspan="2">Challenge</th></tr>
<tr><td>Reliability</td><td>As part of the 2018 IRP Study, ICF found that the reliability of peak period reductions due to DSM investments is unknown, while the need for reliability is particularly high for gas utilities.

In 2020, this has not materially changed. Much of the NPS effort that ICF identified was focused on the development of small-scale pilot projects with the goal of assessing the reliability of the peak demand reductions not only on a given year, but over the long-term.</td></tr>
<tr><td>Lack of metered data</td><td>As part of the 2018 IRP Study, ICF found that accurate metered data on peak period demand is unavailable. Most gas utilities can identify peak hourly data only at a system gate station level, and cited that further granularity is limited.

In 2020, this has not materially changed, except for the few following potential solutions:
• ConEdison is in the process of deploying a gas advanced metering infrastructure (along with its electric advanced metering infrastructure) and should gain access to more accurate data in the coming years.
• In the absence of gas AMI meter data, utilities are using alternate approaches to assess peak demand impacts. For example, the ConEdison residential thermostat gas DR program relied on data gathered by the smart thermostat manufacturers with regards to equipment runtime.
• NW Natural and National Grid plan to launch pilot projects that will be targeted on a specific loop of their distribution system that can be isolated and measured. National Grid intends to infer flow from pressure gauge readings.
• Other utilities, such as FortisBC, are seeking approval to deploy AMI gas meters throughout their service territories.</td></tr>
<tr><td>Additional research</td><td>As part of the 2018 IRP Study, ICF found that additional research would be necessary before gas utilities would be able to rely on demand side NPS alternatives to reduce new facility investments as part of the standard utility facilities planning process. This research needed to include:
• Collection of hourly demand data,
• Assessment of the reliability of using demand-side resources to reduce peak hour demand growth, and
• Assessments of the cost of implementing these types of programs.

The research on these topics remains incomplete. In 2020, we found that utilities such as ConEdison, National Grid, NW Natural, and Central Hudson were still designing pilot projects to address these questions. They are not planning any immediate full-scale deployment of NPS programs. In the short term, due to the challenges associated with building new pipeline capacity into Downstate New York, National Grid and ConEdison will rely on short-term peaking contracts, and CNG injection. The urgency to deploy full-scale EE, gas DR, and electrification will be felt as part of the economic recovery, post COVID-19.

ICF also noted that New York State gas utilities have grown accustomed to the concept of “incentive kickers” (i.e. top-ups to broad-based DSM incentives). A critical research questions that they are posing and attempting to solve through trial and error is: what is a sufficient kicker to obtain measurable increases in adoption in areas of high constraint?</td></tr>
</table>

Challenge	
Changing lead times for projects	As part of the 2018 IRP Study, planning staff from the other utilities indicated that a minimum lead time of 5 years would be required to displace new pipeline projects using geo-targeted DSM. They noted that large customers can have disproportionate impacts on the demand on a network and the timing for additional capacity requirements. In 2020, ICF found that the issue of large customers is less acute in New York State due to the nature of the customer base in this State (i.e. New York State utilities have a significantly smaller proportion of large industrial customers). In addition, ICF's consultations did not find additional evidence to support (or refute) the five-year threshold. In Downstate New York, the problem was not necessarily related with branches of the distribution system under high constraints, but lack of supply at the city gates. The lead time threshold was muddied by the fact that delivered CNG has a short lead time and can be used to extend the waiting time before EE, gas DR, and electrification. NW Natural, Central Hudson, and FortisBC agreed that the lead time is an issue, while being unspecific regarding the threshold.
Changes in the Infrastructure Approval Process for Targeted DSM	As part of the 2018 IRP Study, ICF suggested that the approval process for DSM programs would need to be changed to be consistent with the longer timeframe associated with facilities planning before DSM programs could be relied on as NPS. New York State changed its electricity distribution system plan approval process to systematically incorporate NWS. In 2020, we found that the New York State PSC is considering both extending the time horizon and level of rigor of the long-term gas capacity planning from its gas utilities, and asking for NPS to be considered in a systematic fashion.
Appropriateness of cost-effectiveness testing	As part of the 2018 IRP Study, ICF found that DSM programs may have benefits that combine the attributes of facilities planning and DSM programs, and should be evaluated considering the end user resource costs as well as the benefits of the DSM program on both energy consumption and on the ability of DSM programs to reduce infrastructure investment based on the impact on peak hour/peak day demand (traditional facilities planning). The following approach was employed in ConEdison's BCA Handbook for NPS: • The values of upstream and distribution-level benefits must be stacked. • The values of avoided commodity benefits, peak day demand reductions (for upstream resources), and peak hour demand reductions (for distribution constraints) must also be stacked, as applicable. • Carbon abatement benefits are a key component of the primary decision test, the SCT.

Challenge	
Principle of universality, Cross subsidization	As part of the 2018 IRP Study, the utilities that ICF spoke with were concerned that not offering the same programs across the entire service territory would violate the principle of universality of services to customers and introduce cross-subsidies between customers. NW Natural addressed this issue in their 2020 pilot project with the Energy Trust of Oregon by not offering incremental incentives, and instead intensifying marketing and customer engagement in the area targeted by their geo-targeted EE pilot. The gas utilities in New York State reported not having any issue with this particular challenge. They have NWS as a precedent in the state, and NWS make extensive use of kickers and incentive levels based on location on the electricity system network. Furthermore, ConEdison's BCA Handbook for NPS suggests calculating the RIM, which should help demonstrate a downward impact on rates, thus a benefit to all customers.
Overlap with broad-based DSM	As part of the 2018 IRP Study, ICF found that it would be a challenge to establish cost recovery guidelines for overlapping broad-based DSM and geo-targeted DSM. Electric utilities in New York State have grown accustomed to using incentive kickers to modulate the incentive – in particular, supplementing regular broad-based incentives in areas of high constraint. They fund incentive kickers from different budgets (i.e. capital expenditure budgets). However, this does not seem to be the plan for NPS. Infrastructure such as CNG and LNG would leverage regular operational expenditures and capital expenditures. Gas DR must be funded independently from broad-based DSM budget anyway since it is not in scope of broad-based DSM.

Overall, ICF identified a relatively small number of relevant NPS pilot projects that have been completed in the past three years. We noted that CNG has started being used routinely by gas utilities in New York State, and we identified a number of pilot projects related to geo-targeted EE, gas DR, and electrification, with additional pilot projects underway.

While many of the challenges that were highlighted in the 2018 IRP Study have begun to be addressed, the industry is still a long way from a mature practice of geo-targeted EE, gas DR, and electrification. New York State has a head start compared to other jurisdictions due to its unique circumstances, but there is still much to learn.

In addition, although some utilities have started putting forward "best practices" for discussion – such as the ConEdison's proposed NPA Framework – ICF cannot yet report on a set of "best practices" surrounding NPS.

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