January 15, 2018

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

Dear Ms. Walli:

Re: EB-2017-0127 - Union Gas Limited – DSM Mid-Term Review – Part Two Requirement Two Submission

Enclosed is Union Gas Limited's submission for Part Two Requirement Two of the Mid-Term Review of the 2015-2020 Demand Side Management Framework for Natural Gas Distributors.

If you have any questions concerning this submission, please contact me at (519) 436-4558.

Yours truly,

[*Original Signed by*]

Adam Stiers
Manager, Regulatory Initiatives

c.c.: Myriam Seers (Torys)
Valerie Bennett, OEB Case Manager

DSM MID-TERM REVIEW

PART TWO REQUIREMENT TWO: SUBMISSION OF UNION GAS LIMITED

On June 20, 2017 the Ontario Energy Board (the "Board" or the "OEB") issued a letter outlining the consultation process by which it will undertake the Mid-Term Review of the 2015-2020 Demand Side Management ("DSM") Framework for Natural Gas Distributors (the "DSM Framework"). The letter stated that the Mid-Term Review will be separated into two parts. In the first part, the OEB will undertake a review of the OEB-approved 2015-2020 DSM Framework in the context of the Cap-and-Trade program. Union Gas Limited ("Union") filed its submission for part one on September 1, 2017. The second part requires submission, by Union and Enbridge Gas Distribution Inc. ("Enbridge") (together the "Utilities"), of studies and reports as set out in the OEB's DSM Decision and Order on the Utilities' respective 2015-2020 DSM Plans (the OEB "Decision and Order").[1] These studies and reports were classified into a first requirement, which Union filed on October 2, 2017, and a second requirement, due to be submitted by January 15, 2018. This is Union's submission on the second requirement for part two of the DSM Mid-Term Review. As part of this submission Union is requesting OEB approval of:

- The Residential Adaptive Thermostat offering, including incremental budget funding (pp. 4-6);
- Union's 2018 DSM scorecards (pp. 16-23 and Appendix D);
- Union's 2019-2020 DSM scorecards (pp. 30-48 and Appendix E); and,
- DSM budget and shareholder incentive reallocation procedure (pp. 49-50).

[1] EB-2015-0029/EB-2015-0049, Decision and Order, Schedule D, Mid-Term Review Requirements.

A complete summary of all of Union's requests for OEB approval as part of the Mid-Term Review (including Part One, Part Two Requirement One, and Part Two Requirement Two) is provided in Appendix F.

This submission is organized according to the studies and reports applicable to Union as part of the second requirement in the Decision and Order, and two other items, as follows:

1. Adaptive Thermostats – *Submit results of adaptive thermostat pilot program (Section 5.2.3)*
2. Mass-market Residential Program – *Explore conservation measures and technologies for a mass-market residential program (Section 5.2.3)*
3. Market Transformation Programs – *Provide a summary of market needs and demonstration of how Market Transformation programs are prioritized (Section 5.4)*
4. Open Bill Access – *Develop and expand access to bill for financing purposes related to energy efficiency investments (Section 7)*
5. Outcome-based Performance Metrics – *Provide information related to additional outcome-based performance scorecard metrics (Section 9.2)*
6. Target Adjustment Mechanisms – *Provide suggestions on appropriate changes to the target adjustment formula (Section 9.4)*
7. Integration and Coordination of DSM and CDM Programs – *Provide a progress report related to integrated conservation programs developed with the IESO (Section 11)*
    7.1. The Home Reno Rebate Offering
    7.2. The Commercial/Industrial Direct Install Offering

Appendices

1. **Adaptive Thermostats** – *Submit results of adaptive thermostat pilot program (section 5.2.3)*

In Section 5.2.3 of its Decision and Order, the OEB directed Union to file the results of the Adaptive Thermostat Pilot program, and to consider the adaptive thermostat technology as part of a larger Resource Acquisition program at the Mid-Term Review.

The Adaptive Thermostat Pilot Study can be found in Appendix A. Furthermore, Union proposes the development and implementation of a new adaptive thermostat offering within its Residential program called the Residential Adaptive Thermostat offering. Union proposes that, consistent with Enbridge's OEB-approved Residential Adaptive Thermostat offering, Union's offering provide a $100 rebate to participants for the purchase of a qualifying adaptive thermostat.[2] Wherever possible, Union's offering will be designed and delivered in alignment with Enbridge's offering. By doing so, Union expects that collaboration and synergies can be more effectively pursued among natural gas utilities, electricity utilities, and government-funded initiatives such as GreenON. Union submits that this approach is in alignment with the OEB's comments within the its Decision and Order regarding Enbridge's Residential Adaptive Thermostat offering, specifically that "*from a customer perspective, a thermostat could provide signals to encourage conservation of both gas and electricity*", and that "*thermostat incentives provide a good opportunity for gas and electricity utilities to work together on an integrated program*".[3]

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[2] https://enbridgesmartsavings.com/smart-thermostats
[3] EB-2015-0029, Decision and Order, p. 14.

In order to develop and implement the new Residential Adaptive Thermostat offering through the DSM Framework, Union is requesting OEB approval of incremental budget to facilitate the new offering. Union submits that reallocating funding from existing, successful DSM offerings to new offerings is not appropriate, as it would negatively impact Union's ability to achieve the participation goals for existing offerings which have proven beneficial to customers.

Specifically, Union is requesting OEB approval of an incremental \$1.5 million per year, beginning in 2019. Union's proposed budget is scaled according to Enbridge's 2019 OEB-approved budget for its Residential Adaptive Thermostat offering (\$2.2 million),[4] based on the number of residential customers for each utility.[5] Of the incremental \$1.5 million per year, Union forecasts to spend \$1.3 million on customer incentives, and \$0.2 million on promotion. Union is not proposing additional budget for administration or evaluation costs at this time.

At a customer rebate level of \$100 per unit, and a customer incentive budget of \$1.3 million, Union is forecasting to achieve 13,000 adaptive thermostat participants in 2019. In order to adjust Union's targets to account for the new offering and incremental budget, Union is proposing to add 34,645,000 cumulative natural gas m^3 to the Cumulative Natural Gas Savings (m^3) metric on its 2019 Resource Acquisition scorecard. The proposed target adjustment is based on the following assumptions:

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[4] EB-2015-0029, Decision and Order, pp. 13-14.
[5] Union's franchise includes approximately 1.3 million residential customers (EB-2015-0029, 2015-2020 DSM Plan, Exhibit A, Tab 1, Appendix A, Schedule 5); Enbridge's franchise includes approximately 1.9 million residential customers (EB-2015-0049, 2015-2020 DSM Plan, Exhibit B, Tab 2, Schedule 4).

- Gross annual natural gas savings per adaptive thermostat unit[6] = 185 m^3
- Adaptive thermostat Net-to-Gross adjustment[7] = 96%
- Adaptive thermostat measure life[8] = 15 years

Based on these assumptions, each adaptive thermostat unit saves 2,665 cumulative natural gas m^3 (185 gross annual m^3 x 96% Net-to-Gross adjustment x 15 years measure life). Therefore 13,000 adaptive thermostat participants equates to 34,645,000 cumulative natural gas m^3.

Union's Cumulative Natural Gas Savings (m^3) metric on its 2020 Resource Acquisition scorecard will be determined by the target adjustment mechanism, which will include the results and spend from the 2019 Residential Adaptive Thermostat offering, as well as the budget for the 2020 Residential Adaptive Thermostat offering. Details of Union's 2019 and 2020 Resource Acquisition scorecards, including the proposed adjustments due to the addition of the Residential Adaptive Thermostat offering, can be found in Section 9.1 of this submission. Union's proposed 2019-2020 DSM scorecards can be found in Appendix E.

2. MASS-MARKET RESIDENTIAL PROGRAM – *EXPLORE CONSERVATION MEASURES AND TECHNOLOGIES FOR A MASS-MARKET RESIDENTIAL PROGRAM (SECTION 5.2.3)*

In Section 5.2.3 of its Decision and Order, the OEB denied Union's proposed Energy Savings

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[6] EB-2015-0245, Natural Gas Demand Side Management Technical Resource Manual, p.13, December 22, 2017.
[7] EB-2016-0246, Measures & Assumption Updates, Exhibit B, Tab 1, Schedule 1, p. 1.
[8] EB-2015-0245, Natural Gas Demand Side Management Technical Resource Manual, p.13, December 22, 2017.

Kit ("ESK") offering due to the market reaching saturation. As an alternative to Union's ESK offering the OEB directed Union to propose a new, widespread residential program at the Mid-Term Review.

As per Section 1 of this submission, Union is proposing a new, mass-market Residential Adaptive Thermostat offering for 2019, subject to receiving OEB-approval for the incremental budget required to support its development and implementation.

3. MARKET TRANSFORMATION PROGRAMS – *PROVIDE A SUMMARY OF MARKET NEEDS AND DEMONSTRATION OF HOW MARKET TRANSFORMATION PROGRAMS ARE PRIORITIZED (SECTION 5.4)*

In Section 5.4 of its Decision and Order, the OEB directed the Utilities to *"provide an internally-derived summary of market needs to demonstrate how the selected Market Transformation programs were prioritized and targeted to close those gaps."*[9] Union's DSM portfolio consists of two Market Transformation offerings, the Optimum Home offering and the Commercial Savings by Design offering.

In general, energy conservation program design can be divided into two areas of focus: existing buildings and new construction.[10] While some offerings can be designed to meet the needs of both building types (for example, Union's Commercial/Industrial Prescriptive offering provides

[9] EB-2015-0029, Decision and Order, p. 33.
[10] Existing building offerings focus on improving the energy efficiency of existing buildings, including the existing space heating and water heating equipment, as well as the existing building envelope. New construction offerings focus on improving the energy efficiency of new building developments, usually during the design stage.

fixed incentives for high-efficiency technologies that can be applied to existing or new construction buildings), separate offerings can result in a more effective approach to each building type. Since 2012, two gaps in programming have been identified in the new construction market and have been addressed with Market Transformation offerings by Union. These gaps are explained further below.

The first gap was identified through consultation with stakeholders during the development of Union's 2012-2014 DSM Plan Application. In 2011, prior to the application, Union's energy conservation offerings in the residential new construction market consisted of Drain Water Heat Recovery ("DWHR") and ESK's.[11] Feedback from stakeholders comprised of the need for a more comprehensive approach, including encouraging new home construction above Ontario building code ("OBC").[12] As a result Union designed the Optimum Home offering, with the goal of addressing and overcoming the barriers that prevent widespread construction of high-efficiency homes in the residential new construction market. By targeting the largest builders, the offering seeks to change the building practices of the most influential market participants in order to encourage broader adoption of high-efficiency practices throughout the entire new construction market. Unlike Resource Acquisition programs, which focus on driving energy savings related to the implementation of a specific technology or service (typically accompanied by a financial incentive), Union's Optimum Home offering works with builders to examine all aspects of their business to address the more fundamental barriers to building homes at higher

[11] DWHR pre-heats incoming domestic cold water with available drain water heat that would otherwise be lost. ESKs contain an energy efficient showerhead, energy efficient kitchen aerator, energy efficient bathroom aerator, pipe wrap, teflon tape, and a $25 programmable thermostat coupon.
[12] EB-2011-0327, 2012-2014 DSM Plan, Exhibit A, Tab 1, Appendix D.

efficiency levels. The offering also seeks to address demand-side barriers with homebuyers through education and awareness. Some of the fundamental barriers the offering addresses include:

- The concerns builders have with building high-efficiency homes, including unfamiliarity with, or reluctance to use, new technologies or processes;
- The challenges faced by builder sales teams regarding their ability to convince home buyers of the value of high-efficiency homes; and,
- Competing factors for home buyers such as location, builder reputation, and aesthetic upgrades.

Union submits that Market Transformation continues to be the appropriate approach to the residential new construction market. In conjunction with its other residential offerings (including the Home Reno Rebate offering), Union is providing comprehensive energy conservation programming to residential customers for both existing and new construction building types.

The second gap was identified by Enbridge in the commercial/industrial new construction market, and was addressed with the utility's Commercial Savings by Design offering. Union's 2015-2020 DSM Plan Application did not include an offering specific to the commercial/industrial new construction market, as Union determined that the segment was sufficiently addressed by its Commercial/Industrial Prescriptive offering and Commercial/Industrial Custom offering.[13] However, within its Decision and Order the OEB

[13] Union's Commercial/Industrial Prescriptive offering provides fixed rebates to commercial and industrial customers for the installation of high-efficiency technologies. Union's Commercial/Industrial Custom offering

directed Union to establish an offering similar to Enbridge's, stating that it *"finds commercial and industrial customers would expect consistency in the market, especially for province-wide chains, franchises and companies. From a customer perspective, construction companies would not expect boundaries to gas service territories to limit their ability to access conservation incentives"*.[14] Union subsequently launched its own Commercial Savings by Design offering, in alignment with Enbridge's program design. The offering is designed to inform and educate builders and developers about energy conservation building practices beyond OBC. Builders and developers are provided guidance and expertise throughout the design and development stages of the new construction project, which include learnings that can be carried forward to future projects. In conjunction with its other commercial/industrial offerings (including the Commercial/Industrial Prescriptive offering and Commercial/Industrial Custom offering), Union is providing comprehensive energy conservation programming to commercial/industrial customers for both existing and new construction building types.

It should be noted that while the gaps identified above in the new construction markets were met with Market Transformation offerings, Union has and will continue to address all market needs with the appropriate program design – Market Transformation or Resource Acquisition. For example, as discussed in Section 1 of this submission, Union is proposing a new Resource Acquisition offering, the Residential Adaptive Thermostat offering, to respond to new ways of

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provides rebates for the completion of custom energy efficiency projects not included within the Commercial/Industrial Prescriptive offering. Both offerings are applicable to the existing building and new construction markets.

[14] EB-2015-0029, Decision and Order, p. 39.

achieving energy savings within the residential market. Union submits that program design should continue to be determined based on customers' characteristics and the most effective method of achieving energy savings within a specific market.

4. <u>OPEN BILL ACCESS</u> – *DEVELOP AND EXPAND ACCESS TO BILL FOR FINANCING PURPOSES RELATED TO ENERGY EFFICIENCY INVESTMENTS (SECTION 7)*

In Section 7 of its Decision and Order, the OEB stated that it was encouraged by Enbridge's Open Bill Access program, which allows third party companies to use the utility's bill to charge for services provided to customers. The OEB directed Union to work with Enbridge to establish similar capabilities on its bills.

Union has worked closely with Enbridge to examine the details of its program, in order to adapt Union's systems for a similar program. Union held multiple workshops with Enbridge and Union's Customer Information System ("CIS") service provider to define business requirements and necessary system modifications. Union will begin the development stage of its Open Bill Access program in Q1 2018, and expects to launch the program by Q3 2018.

Specifically, Union's Open Bill Access program will provide third party companies ("Billers") the opportunity to include charges on Union's customer bill. Once approved by Union, Billers will be able to access a secure online web portal to:

- Obtain approval to add charges to a customer's account;

- Upload charges to the customer's account, including re-occurring charges; and,
- Cancel a re-occurring charge.

For a fee per charge, Billers will receive transaction processing, verification, printing, and mailing services from Union. Customers will receive the benefit of one bill, and access to Union's automatic payment option and Union's paperless billing option for services provided by Billers.

Union will establish ongoing communications with Billers to validate and approve customer charges and manage disputed charges. Customers will see Biller charges on a separate page of their Union bill. The Biller's name, description and contact information will also be provided. Customers with inquiries related to Biller charges will be able to contact Union's customer contact centre for assistance. Contact centre agents will have the ability to suspend charges that a customer disputes, which will prevent any further charges from occurring until the matter is resolved with the Biller.

Enbridge conducted a detailed cost study as part of its EB-2009-0043 proceeding. Union has reviewed this analysis and believes the cost model is applicable to Union's program. As a result, Union will charge the same fees as Enbridge for similar services. Effective January 1, 2018, Union will charge $1.015 per charge, exclusive of bad debt flow-through costs.[15] The pricing will be adjusted January 1 annually, by an amount equal to the change in the Consumer Price

[15] Bad debt flow-through costs will be set at 0.49% of revenues for 2018, and are subject to adjustment annually.

Index ("CPI"), to a maximum of 2.5% per year. Union will offer the same pricing to all Billers, which will provide Billers with the benefit of consistency across the two utility franchise areas.

In accordance with OEB direction, Union's Open Bill Access program costs are being funded from the 2018 DSM budget. The program is expected to take time to achieve significant customer interest and as a result program launch and operating costs are expected to exceed income in the initial years of the program. Any revenue associated with energy conservation programs will be returned to the DSM budget to support the development of additional energy efficiency programs. However, Union expects that it will take a number of years before net revenues from energy efficiency programs are generated.

Union will also offer bill insert services to Billers for months when Union's billing envelope does not contain safety and rate information inserts. The bill insert price for 2018 will be established at $0.06 per one-panel insert. Union will update the bill insert pricing in response to market demand on an annual basis. All bill insert prices will be set per one-panel insert, and there will be no volume discounts, minimums, or fixed charges. The number of bill insert slots available to Billers each month will be determined by Union. Union will offer the same pricing to all Billers.

5. OUTCOME-BASED PERFORMANCE METRICS – *PROVIDE INFORMATION RELATED TO ADDITIONAL OUTCOME-BASED PERFORMANCE SCORECARD METRICS (SECTION 9.2)*

In Section 9.2 of its Decision and Order, the OEB approved the Utilities' proposed 2016-2020 metrics for all scorecards. The OEB also stated that it "*generally considers outcome-based performance standards to be the most relevant and appropriate when determining the success of a given activity. Lifetime natural gas savings should continue to be the primary goal of the gas utilities' DSM program efforts*".[16] The OEB also suggested that the Utilities work with stakeholders to develop options for additional outcome-based metrics for consideration at the Mid-Term Review.

Within the existing DSM Framework, the majority of Union's DSM shareholder incentive is determined by its ability to drive lifetime natural gas savings. For illustrative purposes, Table 1 displays Union's 2016 OEB-approved DSM scorecards, the total shareholder incentive weighting for each scorecard, and the percentage of each scorecard that is represented by lifetime natural gas savings metrics. Overall, approximately 80% of Union's 2016 shareholder incentive earnings opportunity is weighted towards lifetime natural gas savings metrics.

[16] EB-2015-0029, Decision and Order, p. 65.

Table 1
Union's Shareholder Incentive Represented by Lifetime Natural Gas Savings Metrics (2016 OEB-approved)

Scorecard	**Shareholder Incentive Weighting[17]**	**% of Scorecard Represented by Lifetime Natural Gas Savings Metrics[18]**	**Shareholder Incentive Earnings Opportunity Represented by Lifetime Natural Gas Savings Metrics**
	(a)	**(b)**	**(a) × (b)**
Resource Acquisition	61%	75%	46%
Low-Income	25%	100%	25%
Large Volume	9%	100%	9%
Market Transformation	4%	0%	0%
Performance-Based	1%	0%	0%
TOTAL	**100%**	**N/A**	**80%**

While lifetime natural gas savings continues to be the primary goal of the Utilities' overall DSM efforts, it is important to note that it is not the appropriate measure for all programs. For example, Market Transformation programs are focused on activities that transform entire markets or industries in the long-term. As such, it would be inappropriate to measure the success of Market Transformation programs using energy savings from the program year. For example, Union's Market Transformation program includes the Optimum Home offering, which addresses adoption barriers related to the construction of high-efficiency homes. An appropriate metric to measure the success of the offering includes the Percentage of Homes Built (>15% above OBC

[17] EB-2015-0029, Decision and Order, Schedule B.
[18] EB-2015-0029, Revised Decision and Order, Schedule C.

2017) by Participating Builders metric, which measures how many homes participating builders are building to increased energy efficiency levels. By focusing on the largest builders within Union's franchise area, the offering is designed to drive changes in building practices in the entire residential new construction market – including with smaller, non-participating builders – over the span of multiple years. For this reason, Union submits that in some cases it is appropriate to measure the success of certain DSM programs with metrics other than lifetime natural gas savings within the program year.

Given the OEB's June 20, 2017 letter, the scope of the Mid-Term Review was limited to *"a review of the mid-term study and reports listed in the DSM Decision and a limited review of the DSM Framework in the context of the C&T program"*.[19] Therefore, Union recommends that a more appropriate time to work with stakeholders to develop options for additional outcome-based metrics would be during the development of the next DSM Framework.

6. <u>Target Adjustment Mechanisms</u> – *Provide suggestions on appropriate changes to the target adjustment formula (Section 9.4)*

In Schedule C of the OEB's Revised DSM Decision and Order on the Utilities' respective 2015-2020 DSM Plans (February 24, 2016) ("Revised Decision and Order") the OEB provided Union's approved DSM scorecards and target adjustment mechanisms for 2016 to 2018.[20] DSM scorecards for 2019 and 2020 were not provided. In Section 9.4 of its Decision and Order, the

[19] EB-2017-0127, OEB Letter, June 20, 2017, p. 2.
[20] EB-2015-0029, Revised Decision and Order, Schedule C.

OEB requested that the Utilities *"suggest any necessary changes to the approved formulaic targets at the midterm review, for 2018 to 2020"*,[21] and that the OEB will *"reassess the formulaic adjustment mechanisms at the mid-term review."*[22] Since OEB-approved DSM scorecards and target adjustment mechanisms were provided up to 2018 only, and 2016 and 2017 program years have concluded at the time of this submission, Union is providing suggested changes to target adjustment mechanisms for 2018 only. For 2019 and 2020, Union is providing its proposed 2019-2020 DSM scorecards within Section 9.1 of this submission.

In Section 9.4 of its Decision and Order, the OEB approved a general target adjustment mechanism based on the utility's cost-effectiveness result from the previous year, adjusted for the current year's OEB-approved budget, and increased by a productivity improvement factor. This formulaic approach is outlined in detail below:

General Target Adjustment Mechanism

Current Year's Target = C × B × Z
Where:
C = previous year's cost-effectiveness for the metric (A÷S)
A = previous year's metric achievement (audited)
S = actual spend to achieve previous year's metric achievement (promotion and incentive spend only)
B = current year's OEB-approved budget for the metric (promotion and incentive spend only)
Z = OEB's productivity improvement factor for the scorecard

Union notes that while the general target adjustment formula described above was used for nine

[21] EB-2015-0029, Decision and Order, p. 72.
[22] EB-2015-0029, Decision and Order, p. 69.

of the 14 2018 metrics, a different approach was used for the remaining five metrics. Fixed targets were used for four of the remaining metrics, and for the fifth remaining metric a three-year rolling average cost effectiveness was used as the basis for the target. A list of each OEB-approved metric for 2018 along with the target setting methodology is provided in Table 2 below.

Table 2
OEB-approved 2018 Metrics and Target Setting Methodologies

Metric #	**Scorecard**	**Offering(s)**	**Metric**	**Target Setting Methodology**
1	Resource Acquisition	Home Reno Rebate, Commercial/Industrial Prescriptive, Commercial/Industrial Custom, Commercial/Industrial Direct Install	Cumulative Natural Gas Savings (m^3)	General Target Adjustment Mechanism C × B × Z
2	Resource Acquisition	Home Reno Rebate	Home Reno Rebate Participants (homes)	General Target Adjustment Mechanism C × B × Z
3	Performance-Based	RunSmart	Participants	General Target Adjustment Mechanism C × B × Z
4	Performance-Based	RunSmart	Savings (%)	General Target Adjustment Mechanism C × B × Z
5	Performance-Based	Strategic Energy Management	Participants	General Target Adjustment Mechanism C × B × Z
6	Performance-Based	Strategic Energy Management	Savings (%)	Fixed Target
7	Large Volume	Large Volume Direct Access	Cumulative Natural Gas Savings (m^3)	Three-year rolling average cost-effectiveness × B × Z
8	Market Transformation	Optimum Home	Participating Builders	Fixed Target
9	Market Transformation	Optimum Home	Prototype Homes Built	Fixed Target

10	Market Transformation	Optimum Home	Percentage of Homes Built (>15% above OBC 2017) by Participating Builders[23]	Fixed Target
11	Market Transformation	Commercial Savings by Design	New Developments Enrolled by Participating Builders	General Target Adjustment Mechanism $C \times B \times Z$
12	Low-Income	Home Weatherization, Furnace End-of-Life Upgrade, Indigenous	Single-Family Cumulative Natural Gas Savings (m^3)	General Target Adjustment Mechanism $C \times B \times Z$
13	Low-Income	Multi-Family	Social and Assisted Multi-Family Cumulative Natural Gas Savings (m^3)	General Target Adjustment Mechanism $C \times B \times Z$
14	Low-Income	Multi-Family	Market Rate Multi-Family Cumulative Natural Gas Savings (m^3)	General Target Adjustment Mechanism $C \times B \times Z$

Union is proposing two changes for 2018, affecting metrics 3, 4, 5, 13 and 14. The first change impacts metrics 3, 4 and 5 and reflects the unique characteristics of the Performance-Based program, which consists of a multi-year incentive structure, causing the general target adjustment mechanism to result in erroneous targets. The second change impacts metrics 13 and 14 and reflects the structure of the OEB-approved budget for the Low-Income program and its

[23] The OEB Revised Decision and Order specified the metric as "Percentage of Homes Built (>20% above OBC 2012) by Participating Builders". Union has interpreted this as a transposition error from the 2016 version of the Optimum Home offering, and has corrected the metric to reflect the 2018 version of the Optimum Home offering.

relationship to the general target adjustment mechanism. Union's two proposed changes are explained in detail below.

1. **Performance-Based Scorecard (Metrics 3, 4, and 5) –** For 2018 Union is proposing to use the previous year's actual achievement (rather than the previous year's cost-effectiveness) as the basis for the targets for the RunSmart offering Participants metric (Metric 3 in Table 2), the RunSmart offering Savings (%) metric (Metric 4 in Table 2), and the Strategic Energy Management offering Participants metric (Metric 5 in Table 2). The proposed target setting methodology is as follows:

   Current Year's Target = A × Z
   Where:
   A = previous year's metric achievement (audited)
   Z = OEB's productivity improvement factor for the scorecard

   The RunSmart offering and the Strategic Energy Management offering incentive structures are unique in that they require incentive payments to be deferred across multiple years. Therefore, calculating cost-effectiveness using a single year's expenditure results in an inaccurate cost-effectiveness figure, and using cost-effectiveness as the basis for the following year's target results in an erroneous target. As an example, new RunSmart participants in 2017 are provided site assessments to identify potential recommissioning activities, and the cost of the site assessments are funded in 2017. In 2018, 12 months after the site assessments and recommissioning activities have been completed, the customer is provided with an incentive based on realized savings. As a result of the 12-month delay in incentive payments, the 2017 offering spend (and therefore 2017 cost-effectiveness) does not include incentive payments, which are paid in 2018. By using the 2017 cost-effectiveness as the basis for the 2018 target, the result is an erroneous target. For this reason, Union submits that it is not appropriate to use the previous year's cost-effectiveness as the basis for the following year's target for offerings with incentive structure payments deferred across multiple years, as is the case with the RunSmart offering and the Strategic Energy Management offering. Instead, Union proposes to use the previous year's actual achievement as the basis for the following year's target.

2. **Low-Income Scorecard** (**Metrics 13 and 14) –** For 2018 Union is proposing to combine the Social and Assisted Multi-Family Cumulative Natural Gas Savings (m^3) metric (Metric 13 in Table 2) and the Market Rate Multi-Family Cumulative Natural Gas Savings (m^3) metric (Metric 14 in Table 2) into a single Multi-Family Cumulative Natural Gas Savings (m^3) metric. Union is proposing this change in order to align the general target adjustment mechanism with the structure of the OEB-approved budget, which does not include separate OEB-approved budget amounts for the social and assisted component and the market rate component of the offering.[24] The OEB-approved budget is only available as a single figure representing the entire Multi-Family offering. Union submits that it is appropriate to align the general target adjustment mechanism with the structure of the OEB-approved budget, resulting in a single Multi-Family Cumulative Natural Gas Savings (m^3) metric.

[24] EB-2015-0029, Decision and Order, Schedule B.

A summary of Union's proposed changes to the 2018 target adjustment mechanisms are provided Table 3 below, with the proposed changes highlighted in bold. Union's proposed 2018 DSM scorecards, reflecting the proposed changes, are provided in Appendix D. Union is requesting OEB approval of Appendix D.

Table 3
Proposed 2018 Metrics

Metric #	**Scorecard**	**Offering(s)**	**Metric**	**Target Setting Methodology**
1	Resource Acquisition	Home Reno Rebate; Commercial/Industrial Prescriptive; Commercial/Industrial Custom; Commercial/Industrial Direct Install.	Cumulative Natural Gas Savings (m^3)	General Target Adjustment Mechanism C × B × Z
2	Resource Acquisition	Home Reno Rebate	Home Reno Rebate Participants (homes)	General Target Adjustment Mechanism C × B × Z
3	**Performance-Based**	**RunSmart**	**Participants**	**A × Z**
4	**Performance-Based**	**RunSmart**	**Savings (%)**	**A × Z**
5	**Performance-Based**	**Strategic Energy Management**	**Participants**	**A × Z**
6	Performance-Based	Strategic Energy Management	Savings (%)	Fixed Target
7	Large Volume	Large Volume Direct Access	Cumulative Natural Gas Savings (m^3)	Three-year rolling average CE × B × Z
8	Market Transformation	Optimum Home	Participating Builders	Fixed Target
9	Market Transformation	Optimum Home	Prototype Homes Built	Fixed Target
10	Market Transformation	Optimum Home	Homes Built (>15% above OBC 2017) by Participating	Fixed Target

			Builders[25]	
11	Market Transformation	Commercial Savings by Design	New Developments Enrolled by Participating Builders	General Target Adjustment Mechanism C × B × Z
12	Low-Income	Home Weatherization; Furnace End-of-Life Upgrade; Indigenous.	Single-Family Cumulative Natural Gas Savings (m^3)	General Target Adjustment Mechanism C × B × Z
13	**Low-Income**	**Multi-Family**	**Multi-Family Cumulative Natural Gas Savings (m^3)**	**General Target Adjustment Mechanism C × B × Z**

7. <u>INTEGRATION AND COORDINATION OF DSM AND CDM PROGRAMS</u> – *PROVIDE A PROGRESS REPORT RELATED TO INTEGRATED CONSERVATION PROGRAMS DEVELOPED WITH THE IESO (SECTION 11)*

In Section 11 of the its Decision and Order, the OEB expressed concern with the progress made between natural gas utilities and electricity distributors with respect to collaborative energy conservation programming. The OEB stated that the gas utilities should be in a position to report on the progress made in developing integrated conservation programs at the Mid-Term Review. Further, the OEB stated its expectation for at least one jointly offered program to be available in market by the Mid-Term Review.[26] In response to the OEB's direction, Union has developed two integrated natural gas and electricity energy conservation offerings: the Home Reno Rebate

[25] The OEB's Revised Decision and Order specified the metric as "Percentage of Homes Built (>20% above OBC 2012) by Participating Builders". Union has interpreted this as a transposition error from the 2016 version of the Optimum Home offering, and has corrected the metric to reflect the 2018 version of the Optimum Home offering.
[26] EB-2015-0029, Decision and Order, p. 82.

offering, and the Commercial/Industrial Direct Install offering.

7.1. The Home Reno Rebate Offering

In Section 5.2.1 of the its Decision and Order, the OEB approved Union's Home Reno Rebate offering as proposed in Union's 2015-2020 DSM Plan.[27] Participants of the offering work with a partnered third party service organization ("Service Organization") to complete an initial home energy assessment (known as the "D assessment") to establish their home's current energy use and identify energy savings opportunities. Rebates are made available for implementing energy saving opportunities identified in the D assessment, including:

- Basement insulation;
- Exterior wall insulation;
- Attic insulation;
- Air sealing;
- High-efficiency natural gas furnaces and boilers;
- High efficiency natural gas water heaters; and,
- ENERGY STAR-qualified windows/doors/skylights.

After the upgrades are made, participants work with the Service Organization to complete a second home energy assessment (known as the "E assessment") to determine the resulting energy savings. Union provides a rebate for the D and E assessments, up to $500, intended to

[27] EB-2015-0029, Decision and Order, p. 13.

cover the full cost of both assessments.[28] As part of the DSM Framework, the offering was made available to Union's customers only.

In 2016, subsequent to the OEB's Decision and Order, Union entered into a partnership with the Ministry of Energy ("MOE") to provide funding, through the Ontario Green Investment Fund, to enhance Union's Home Reno Rebate offering. Through this partnership, the following enhancements were made:

- Expanded eligibility for participation, including: Homes that use oil, propane, or wood as their primary heating fuel; and, Homes that use natural gas as their primary heating fuel but are not serviced by Union or Enbridge.
- New rebates for: High-efficiency oil furnaces and boilers, High-efficiency propane furnaces and boilers, High-efficiency wood burning systems, Air-source heat pumps, and Adaptive thermostats.
- Increased rebate levels for measures already included in the offering.

Similarly, Enbridge entered into a separate partnership with the MOE to enhance its residential home retrofit offering. While the Utilities continue to administer their offerings separately, a common website was developed that allows any homeowner in Ontario to identify which offering they are eligible to participate in by entering their postal code.[29] Once the homeowner's appropriate offering is identified, the website provides information about the energy conservation

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[28] EB-2015-0029, 2015-2020 DSM Plan, Exhibit A, Tab 3, Appendix A, pp. 3-8.

[29] https://www.ohecip.ca

offering, including the steps required to initiate participation.

In 2017, subsequent to the Utilities' partnerships with the MOE, the Utilities entered into partnerships with the Independent Electricity System Operator ("IESO") to further enhance their respective offerings. Through the partnerships, the following enhancements were made:

- Expanded eligibility for participation, including homes that use electricity as their primary heating source.
- Expanded scope for the home energy assessment to include electric measures.
- New rebates for: High-efficiency central air conditioners; Electrically commutated motors for natural gas furnaces; ENERGY STAR-qualified refrigerators; ENERGY STAR-qualified freezers; ENERGY STAR-qualified dehumidifiers; ENERGY STAR-qualified window air conditioners; and, ENERGY STAR-qualified clothes washers.
- Increased rebate levels for air source heat pumps.

The partnerships established between the Utilities, the IESO, and the MOE, provide a comprehensive, province-wide home retrofit offering available to all natural gas, electricity, oil, propane, and wood heated homes in Ontario. Union understands this to be the first energy conservation offering of its kind, utilizing funding from three different sources (the DSM Framework, the IESO's Conservation First Framework, and the provincial government) to provide an energy conservation offering to all single-family residential customers in Ontario through a single touch-point.

7.2. The Commercial/Industrial Direct Install Offering

Within Union's 2015-2020 DSM Plan Application, Union proposed the Commercial/Industrial Direct Install offering.[30] The offering provides small commercial customers with increased rebate levels for prescriptive high-efficiency technologies, and includes free installation. The offering strives to increase awareness and knowledge of energy efficiency with small commercial customers, who typically do not participate in traditional DSM programs due to limited availability of resources. Union originally proposed to test the offering as a pilot, however, within Section 5.2.5 of its Decision and Order, the OEB directed Union to proceed with it as a standard offering.

In an effort to deliver the offering as effectively as possible, Union partnered with Alectra Utilities ("Alectra") in 2017 to co-deliver its Commercial/Industrial Direct Install offering with Alectra's Small Business Lighting program. Through a shared delivery agent, the partnership provides small business customers in the Hamilton area the ability to participate in a joint natural gas and electricity conservation program through one point-of-contact and one on-site audit. Through the partnership, a small business customer can receive free installation of pedestrian door air curtains (via Union's Commercial/Industrial Direct Install offering),[31] and free installation of energy efficient lighting (via Alectra's Small Business Lighting program) through a single touch-point.

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[30] EB-2015-0029, Exhibit A, Tab 3, Appendix A, pp. 30-36.
[31] Air curtains deliver a controlled stream of air that separates indoor and outdoor environments.

8. **INTEGRATED RESOURCE PLANNING** – *SUBMIT A TRANSITION PLAN TO INCORPORATE DSM INTO INFRASTRUCTURE PLANNING ACTIVITIES (SECTION 12)*

In Section 12 of its Decision and Order, the OEB directed the Utilities to work jointly on a transition plan to incorporate DSM into the Utilities' infrastructure planning activities and requested that the Utilities file the transition plan at the Mid-Term Review. In 2016 the Utilities jointly engaged ICF International to support the development of a transition plan. The transition plan serves as the Utilities' roadmap to implementing formalized Integrated Resource Planning ("IRP"). IRP refers to a *"multi-faceted planning process that includes the identification, preparation, and evaluation of all realistic supply side and demand side options in order to determine the least cost for customers and lowest risk approach to addressing transmission and distribution infrastructure requirements."*[32]

The transition plan:[33]

- Identifies the process phases the Utilities will move through to ensure DSM is included within the Utilities' infrastructure planning activities;
- Indicates how the Utilities should internally organize themselves to ensure DSM is included within the Utilities' infrastructure planning activities; and,
- Indicates an internal governance structure to ensure appropriate implementation of IRP.

The transition plan is provided in Appendix B.

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[32] Appendix B, p. 3.
[33] Appendix B, p. 5.

The Utilities also engaged ICF International to develop an IRP Study to assess the potential of employing targeted DSM activities with the goal of influencing future natural gas infrastructure investments. An Executive Summary for the IRP Study is provided in Appendix C. The Executive Summary includes the following:

- Introduction, Scope and General Conclusions;
- Review of Industry Experience;
- Overview of Natural Gas Facility Planning;
- Differences between Facilities and DSM Planning Criteria and Approach;
- DSM Impacts on Peak Day and Peak Hour Demand;
- Potential Impacts of DSM on Facilities Requirements;
- Policy Considerations; and,
- Conclusions and Recommendations.

The Executive Summary identifies the need for further research to test the IRP Study findings in-field. Accordingly, case studies are underway by the Utilities to further inform the IRP Study, to create a better understanding of the impacts of broad-based DSM programs and technologies on peak hour demand.

Union expects that in addition to the requirements outlined above that consideration will be made in due course for changes that could be realized as a result of the current Mergers, Acquisitions, Amalgamations and Divestitures (“MAADs”) Application before the OEB that contemplates the amalgamation of Union and Enbridge.

9. Other Items

9.1. Proposed 2019-2020 DSM Scorecards

As part of the OEB's revised Decision and Order, OEB-approved DSM scorecards were provided to the Utilities for 2016 to 2018 only.[34] Therefore, Union is proposing its 2019 and 2020 DSM scorecards within this submission. Details for each scorecard are provided below, and a summary of Union's proposed 2019 and 2020 DSM scorecards are provided in Appendix E. Union is requesting OEB approval of Appendix E.

9.1.1 Resource Acquisition Scorecard

Union's proposed 2019 and 2020 Resource Acquisition scorecards consist of two programs, the Residential program and the Commercial/Industrial program. Union's Residential program consists of one offering, the Home Reno Rebate offering. Union's Commercial/Industrial program consists of three offerings, the Commercial/Industrial Prescriptive offering, the Commercial/Industrial Custom offering, and the Commercial/Industrial Direct Install offering. This remains unchanged from Union's OEB-approved 2016 to 2018 Resource Acquisition scorecards.

Union's Home Reno Rebate offering provides rebates to residential customers for the completion of an initial home energy assessment: to establish their home's current energy use and identify energy savings opportunities, for implementing energy saving opportunities identified in the

[34] EB-2015-0029, Revised Decision and Order, Schedule C.

initial home energy assessment, and for the completion of a second home energy assessment to determine energy savings. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[35]

Union's Commercial/Industrial Prescriptive offering provides fixed rebates to commercial and industrial customers for the installation of high-efficiency technologies. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[36]

Union's Commercial/Industrial Custom offering provides rebates for energy conservation projects related to unique building specifications, design concepts, processes and/or new technologies that are outside the scope of the Commercial/Industrial Prescriptive offering. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[37]

Union's Commercial/Industrial Direct Install offering provides small commercial customers with increased rebate levels for prescriptive high-efficiency technologies, and includes free installation. The offering strives to increase awareness and knowledge of energy efficiency with small commercial customers, who typically do not participate in traditional DSM programs due to limited availability of resources. Union proposed to test the offering as a pilot within its 2015-

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[35] EB-2015-0029, Decision and Order, p. 13.
[36] EB-2015-0029, Decision and Order, p. 17.
[37] EB-2015-0029, Decision and Order, p. 21.

2020 DSM Plan Application. The OEB found that the offering should not be a pilot, and instead the directed Union to proceed as a standard offering.[38]

Union proposed its 2016 Resource Acquisition scorecard using fixed targets, and its 2017 to 2020 Resource Acquisition scorecards using a target adjustment mechanism based on the previous year's cost-effectiveness, within its 2015-2020 DSM Plan. The OEB approved Union's 2016 Resource Acquisition scorecard, but increased Union's proposed targets by 10%. The OEB also approved Union's 2017 and 2018 Resource Acquisition scorecards, but added a 2% productivity factor to the proposed target adjustment formula. The OEB also modified the upper band targets to 150% of target for all metrics.

Union is proposing 2019 and 2020 Resource Acquisition scorecards in the same format as its OEB-approved 2017 and 2018 Resource Acquisition scorecards. Union's proposed 2019 and 2020 Resource Acquisition scorecards can be found in Table 4 below, and in Appendix E.

[38] EB-2015-0029, Decision and Order, p. 18.

Table 4
Union's Proposed 2019 and 2020 Resource Acquisition Scorecards

Union Gas 2019 Resource Acquisition Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Home Reno Rebate; Commercial/Industrial Prescriptive; Commercial/Industrial Custom; Commercial/Industrial Direct Install.	Cumulative Natural Gas Savings (m^3)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	75%
Home Reno Rebate	Home Reno Rebate Participants (Homes)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	25%

Union Gas 2020 Resource Acquisition Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Home Reno Rebate; Commercial/Industrial Prescriptive; Commercial/Industrial Custom; Commercial/Industrial Direct Install.	Cumulative Natural Gas Savings (m^3)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	75%
Home Reno Rebate	Home Reno Rebate Participants (Homes)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	25%

Upon OEB approval of Union's proposed Residential Adaptive Thermostat offering within the Residential program, as per Section 1 of this submission, an additional 34,645,000 m^3 will be added to the Cumulative Natural Gas Savings (m^3) metric target for the 2019 scorecard, to account for the new offering and incremental budget. Furthermore, the *"2019 offering budget without overheads"* figure within the target adjustment mechanism will not include the incremental Residential Adaptive Thermostat offering budget. Specifically, the target adjustment mechanism for the Cumulative Natural Gas Savings (m^3) metric for the 2019 scorecard will be:

2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads (not including the Residential Adaptive Thermostat offering) × 1.02 + 34,645,000 m^3

The target adjustment mechanism for the Cumulative Natural Gas Savings (m^3) metric on the 2020 scorecard will remain unchanged, and will include the results and spend from the 2019 Residential Adaptive Thermostat offering, and the budget for the 2020 Residential Adaptive Thermostat offering.

9.1.2 Low-Income Scorecard

Union's proposed 2019 and 2020 Low-Income scorecards consist of one program, the Low-Income program. Union's Low-Income program consists of four offerings: the Home Weatherization offering, the Furnace-End-of-Life Upgrade offering, the Indigenous offering, and the Multi-Family offering. This remains unchanged from Union's OEB-approved 2016 to 2018 Low-Income scorecards.

Union's Home Weatherization offering provides a free home energy assessment to qualified homeowners and tenants to determine the home's building envelope upgrade requirements. Furthermore, the offering provides free installation of all qualifying building envelope upgrades. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[39]

Union's Furnace-End-of-Life Upgrade offering provides qualified homeowners and tenants with an incentive to upgrade to a high-efficiency furnace when their existing furnace reaches its end-of-life. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[40]

Union's Indigenous offering provides the Home Weatherization offering and Furnace-End-of-Life Upgrade offering to customers living in Indigenous communities within Union's franchise area. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[41]

Union's Multi-Family offering provides the social and assisted housing, and low-income market rate multi-family segments with prescriptive and custom incentives for energy efficiency upgrades. The offering is designed similar to the Commercial/Industrial Prescriptive and Commercial/Industrial Custom offerings. Incentives included in this offering are enhanced to reflect the barriers to participation that exist within the low-income market. The offering was

[39] EB-2015-0029, Decision and Order, p. 26.
[40] EB-2015-0029, Decision and Order, p. 28.
[41] EB-2015-0029, Decision and Order, p. 27.

proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[42]

Union proposed its 2016 Low-Income scorecard using fixed targets, and its 2017 to 2020 Resource Acquisition scorecards using a target adjustment mechanism based on the previous year's cost-effectiveness, within its 2015-2020 DSM Plan Application. The OEB approved Union's proposed 2016 Low-Income scorecard, but increased Union's proposed targets by 10%. The OEB also approved Union's 2017 and 2018 Low-Income scorecards, but added a 2% productivity factor to the proposed target adjustment formula. The OEB also modified the upper band targets to 150% of target for all metrics.

Union is proposing 2019 and 2020 Low-Income scorecards in the same format as its OEB-approved 2017 and 2018 Low-Income scorecards, with a single modification to combine the Social and Assisted Multi-Family Cumulative Natural Gas Savings (m^3) metric and the Market Rate Multi-Family Cumulative Natural Gas Savings (m^3) metric into a single Multi-Family Cumulative Natural Gas Savings (m^3) metric. Union is proposing this change to in order to align the target adjustment mechanism with the structure of the OEB-approved budget, which includes only a single amount for the Multi-Family offering, and does not include separate OEB-approved budget amounts for the social and assisted component and the market rate component of the offering.[43] This proposed change to the 2019 and 2020 Low-Income scorecard is consistent with

[42] EB-2015-0029, Decision and Order, p. 30.
[43] EB-2015-0029, Decision and Order, Schedule B.

Union's proposed change to the 2018 Low-Income scorecard described in Section 6 of this submission.

Union's proposed 2019 and 2020 Low-Income scorecards can be found in Table 5 below, and in Appendix E.

Table 5
Union's Proposed 2019 and 2020 Low-Income Scorecards

Union Gas 2019 Low-Income Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Home Weatherization; Furnace End-of-Life Upgrade; Indigenous.	Single-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	60%
Multi-Family	Multi-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	40%

Union Gas 2020 Low-Income Scorecard					
Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
Home Weatherization Furnace End-of-Life Upgrade Indigenous	Single-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	60%
Multi-Family	Multi-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	40%

9.1.3 Large Volume Scorecard

Union's proposed 2019 and 2020 Large Volume scorecards consist of one program, the Large Volume program. Union's Large Volume program consists of one offering, the Large Volume Direct Access offering. This remains unchanged from Union's OEB-approved 2016 to 2018 Large Volume scorecards.

Based on consultation with customers, Union proposed a Large Volume offering within its 2015-2020 DSM Plan Application that provided customers with training resources, to ensure a continued focus on energy efficiency among its large volume customers. The offering was proposed for the 2016 to 2020 term at a budget of approximately $0.8 million per year, and did not include scorecards. However, in its Decision and Order, the OEB directed Union to continue with a Direct Access offering, similar to its 2015 offering, at a budget of $4 million per year. The

OEB provided an approved 2016 Large Volume scorecard, with a target setting methodology that utilized a three-year rolling average cost-effectiveness as the basis, with a 2% productivity improvement factor, and discounted by 25% to account for a delayed launch due to the timing of its Decision and Order.[44] The OEB also provided approval of 2017 and 2018 Large Volume scorecards within the Revised DSM Decision and Order .[45]

Union is proposing 2019 and 2020 Large Volume scorecards in the same format as its OEB-approved 2017 and 2018 Large Volume scorecards. Union's proposed 2019 and 2020 Large Volume scorecards can be found in Table 6 below, and in Appendix E.

Table 6
Union's Proposed 2019 and 2020 Large Volume Scorecards

Union Gas 2019 Large Volume Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Large Volume Direct Access	Cumulative Natural Gas Savings (m^3)	75% of Target	Three-year rolling average (2016-2018) offering cost-effectiveness × 2019 offering budget without overheads × 1.02	150% of Target	100%

[44] EB-2015-0029, Decision and Order, pp. 51-52.
[45] EB-2015-0029, Revised Decision and Order, Schedule C.

Union Gas 2020 Large Volume Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Large Volume Direct Access	Cumulative Natural Gas Savings (m^3)	75% of Target	Three-year rolling average (2017-2019) offering cost-effectiveness × 2020 offering budget without overheads × 1.02	150% of Target	100%

9.1.4 Market Transformation Scorecard

Union's proposed 2019 and 2020 Market Transformation scorecard consists of one program, the Market Transformation program. Union's Market Transformation program consists of two offerings, the Optimum Home offering and the Commercial Savings by Design offering. This remains unchanged from Union's OEB-approved 2016 to 2018 Market Transformation scorecards.

Union's Optimum Home offering addresses adoption barriers related to the construction of high efficiency homes, thereby avoiding lost opportunities and setting the stage for long-term energy savings in the residential market. The Optimum Home offering examines all aspects of a home builder's business, in an attempt to create fundamental change towards more energy efficient building practices. Within Union's 2015-2020 DSM Plan Application, the Optimum Home offering was designed to help builders build homes at energy efficiency levels 20% greater than the OBC 2012. At the time of Union's 2015-2020 DSM Plan Application, OBC 2012 was expected to be replaced by a new building code, OBC 2017. However, details of OBC 2017 were not available. Union proposed to end the OBC 2012 version of the Optimum Home offering at the end of 2016 and committed to investigating an OBC 2017 version of the Optimum Home offering once details of the new building code were available. However, within its Decision and Order, the OEB directed Union to continue its Optimum Home offering from 2017 to 2020 with an annual budget equal to that in 2016, and with a program design that helps builders build homes at energy efficiency levels 15% greater than OBC 2017.[46] Union subsequently filed proposed 2017 to 2020 Optimum Home offering metrics for its Market Transformation scorecards within its February 3, 2016 Written Comments to the OEB's Decision and Order. [47] The OEB approved Union's proposed 2017 and 2018 Optimum Home offering metrics with modifications to the lower band and upper band targets, and deferred the approval of 2019 and 2020 metrics to the Mid-Term Review.[48]

Union submits that its 2019 and 2020 Optimum Home offering metrics as proposed in its February 3, 2016 Written Comments to the OEB's Decision and Order continue to be appropriate, subject to the following modifications:

1. Modify the lower band and upper band targets to 75% of target and 150% of target for each metric respectively, as per the OEB's modifications to Union's proposed 2017 and 2018 Optimum Home offering metrics.[49]
2. Modify the target setting methodology for the Prototype Homes Built Percentage of Homes Built (>15% above OBC 2017) by Participating Builders metric to align with the OEB-approved general target adjustment mechanism provided in section 9.4 of the

[46] EB-2015-0029, Decision and Order, pp. 35-36.
[47] EB-2015-0029, Union 2015-2020 DSM Plan Written Comments, pp. 4-6.
[48] EB-2015-0029, Revised Decision and Order, pp. 4-5.
[49] EB-2015-0029, Revised Decision and Order, pp. 4-5.

OEB's Decision and Order.[50]

The proposed target adjustment mechanism for the metric in 2019 is:

2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads ×1.1

The proposed target adjustment mechanism for the metric in 2020 is:

2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.1

Union's Commercial Savings by Design offering is designed to improve the long-term energy and environmental performance of new commercial construction projects. The offering was proposed by Enbridge within its 2015-2020 DSM Plan Application and approved by the OEB.[51] The OEB also directed Union to establish a similar program, and provided a Commercial Savings by Design offering metric (New Developments Enrolled by Participating Builders metric) as part of Union's approved 2016 to 2018 Market Transformation scorecards. The 2016 metric used a fixed target, and the 2017 and 2018 metrics used the general target adjustment mechanism provided in Section 9.4 of the OEB's Decision and Order.[52]

Union proposes to maintain the New Developments Enrolled by Participating Builders metric

[50] EB-2015-0029, Decision and Order, p. 69.
[51] EB-2015-0029, Decision and Order, pp. 38-40.
[52] EB-2015-0029, Decision and Order, p. 69.

using the general target adjustment mechanism as the Commercial Savings by Design offering metric in 2019 and 2020.

Union proposes that the Optimum Home offering metrics continue to represent 50% of its Market Transformation scorecard, with the remaining 50% represented by the Commercial Savings by Design offering, consistent with Union's OEB-approved 2016 to 2018 Market Transformation scorecards. Union's proposed 2019 and 2020 Market Transformation scorecards can be found in Table 7 below, and in Appendix E.

Table 7
Union's Proposed 2019 and 2020 Market Transformation Scorecards

Union Gas 2019 Market Transformation Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Optimum Home	Participating Builders (Regional Top 10)[53]	3	4	6	10%
	Prototype Home Built[54]	67.5%	90%	100%	10%
	Homes Built (>15% above OBC 2017) by Participating Builders[55]	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.1	150% of Target[56]	30%
Commercial Savings by Design	New Developments Enrolled by Participating Builders	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.1	150% of Target	50%

[53] Incremental builders enrolled in the program year for the 15% greater than OBC 2017 program cycle. Eligible builders are the top 10 builders in each region based on number of housing starts in Union's franchise area in prior calendar year. The seven regions are: Halton, Hamilton, London, Waterloo, Windsor, Kingston and North.
[54] Percentage of participating builders who have constructed a prototype home at least 15% greater than OBC 2017, based on the total number of builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the number of participating builders who have constructed a prototype home which has been certified to at least a 15% higher energy efficiency standard than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of builders who remain enrolled in the program.
[55] Calculated as the percentage of homes built to a 15% higher energy efficiency standard than OBC 2017 in relation to the total number of homes built in a program year by participating builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the total number of residential homes constructed by participating builders certified to at least 15% greater than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of residential homes constructed between January 1 and December 31 of the program year as per the Union Gas customer attachment report by participating builders who remain enrolled in the program. This report includes all residential homes listed by builder who requested the service. Homes are included in the report when their Union Gas account is activated.
[56] Upper Band figure capped at 100%.

Union Gas 2020 Market Transformation Scorecard					
Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
Optimum Home	Homes Built (>15% above OBC 2017) by Participating Builders[57]	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.1	150% of Target[58]	50%
Commercial Savings by Design	New Developments Enrolled by Participating Builders	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.1	150% of Target	50%

9.1.5 Performance-Based Conservation Scorecard

Union's proposed 2019 and 2020 Performance-Based scorecards consist solely of the Performance-Based program. Union's Performance-Based program contains two offerings, the RunSmart offering and the Strategic Energy Management offering. This remains unchanged from Union's OEB-approved 2016 to 2018 Performance-Based scorecards.

Union's RunSmart offering assists customers with the recommissioning of building space heating and domestic hot water equipment, control systems, as well as building envelope integrity. The focus of the RunSmart offering is to identify low-cost or no-cost building

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[57] Calculated as the percentage of homes built to a 15% higher energy efficiency standard than OBC 2017 in relation to the total number of homes built in a program year by participating builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the total number of residential homes constructed by participating builders certified to at least 15% greater than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of residential homes constructed between January 1 and December 31 of the program year as per the Union Gas customer attachment report by participating builders who remain enrolled in the program. This report includes all residential homes listed by builder who requested the service. Homes are included in the report when their Union Gas account is activated.
[58] Upper Band figure capped at 100%.

optimization and operation and maintenance ("O&M") improvements. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[59]

Union's Strategic Energy Management offering is a long-term, deep savings initiative whereby a customer's energy performance is tracked and measured against their baseline performance, established through their first year of participation in the offering. Incentives and in-kind technical support is available to participants for start-up evaluation, implementation of a monitoring system, as well as for demonstrated energy performance improvements over time. The offering was proposed by Union within its 2015-2020 DSM Plan Application and subsequently approved by the OEB.[60]

Within its 2015-2020 DSM Plan Application, Union proposed Performance-Based scorecards for 2016 to 2020.[61] The OEB approved Union's 2016 to 2018 scorecards, with the following modifications:

1. For fixed targets proposed beyond the first year of a metric, the OEB modified the targets to utilize the general target adjustment mechanism provided in section 9.4 of its Decision and Order.[62] The OEB maintained Union's proposed fixed targets for the first year of metrics.
2. For formulaic targets, which were proposed by Union to be based on the previous year's actual achievement, the OEB modified the targets to utilize the general target adjustment

[59] EB-2015-0029, Decision and Order, p. 46.
[60] EB-2015-0029, Decision and Order, p. 48.
[61] EB-2015-0029, Exhibit A, Tab 3, pp. 32-33.
[62] EB-2015-0029, Decision and Order, p. 69.

mechanism provided in section 9.4 of its Decision and Order.[63] The general target adjustment mechanism is based on the previous year's cost-effectiveness.

3. The OEB modified the lower band and upper band targets to 75% of target and 150% of target, respectively, for each metric.

Union submits that the 2019 and 2020 Performance-Based scorecard metrics proposed in its 2015-2020 DSM Plan Application continue to be appropriate,[64] subject to the following modifications:

1. Modify the lower band and upper band targets to 75% of target and 150% of target for each metric respectively, as per the OEB's modifications to Union's proposed 2017 and 2018 Performance-Based scorecard metrics.[65]
2. Modify the target setting methodology for all metrics to use the previous year's achievement as the basis for the following year's target. As described in Section 6 of this submission, Union submits that it is not appropriate to use the general target adjustment mechanism for the Performance-Based scorecard due to the multi-year incentive structure of the Performance-Based offerings.

The proposed target adjustment mechanism for the metric in 2019 is:

2018 actual achievement × 1.1

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[63] EB-2015-0029, Decision and Order, p. 69.
[64] EB-2015-0029, Exhibit A, Tab 3, pp. 32-33.
[65] EB-2015-0029, Revised Decision and Order, pp. 4-5.

The proposed target adjustment mechanism for the metric in 2020 is:

2019 actual achievement × 1.1

Union's proposed 2019 and 2020 Performance-Based scorecards can be found in Table 8 below, and in Appendix E.

Table 8
Union's Proposed 2019 and 2020 Performance-Based Scorecards

Union Gas 2019 Performance-Based Scorecard					
Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
RunSmart	Participants	75% of Target	2018 Actual Achievement × 1.1	150% of Target	10%
	Savings (%)	75% of Target	2018 Actual Achievement × 1.1	150% of Target	40%
Strategic Energy Management	Savings (%)	75% of Target	2018 Actual Achievement × 1.1	150% of Target	50%

Union Gas 2020 Performance-Based Scorecard					
Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
RunSmart	Participants	75% of Target	2019 Actual Achievement × 1.1	150% of Target	10%
	Savings (%)	75% of Target	2019 Actual Achievement × 1.1	150% of Target	40%
Strategic Energy Management	Savings (%)	75% of Target	2019 Actual Achievement × 1.1	150% of Target	50%

9.2 Proposed DSM Budget and Shareholder Incentive Reallocation Procedure

As evident by the MOE's directive to the IESO on August 4, 2017, as well as by recent GreenON Request for Proposal's ("RFP"), the provincial government has begun commissioning Cap-and-Trade auction funded energy conservation programs that compete directly with, and in some cases duplicate, the Utilities' existing proven DSM programs.[66] While Union supports increased funding for energy conservation programs in Ontario, Union submits that in order for Ontario's GHG emissions reduction targets to be met, and to ensure that funding from all sources is spent as effectively as possible, it is crucial that regulators and government clearly distinguish new Cap-and-Trade funded conservation programs from existing DSM programs. Union's position is supported by Ontario's Environmental Commissioner, who states in an August 2017 report *"Given its climate mitigation potential, funding for gas conservation is also being made available by the Ontario government from cap and trade proceeds. Careful oversight will be needed to ensure that these initiatives do not conflict and that utility programs continue to be delivered effectively"*.[67]

Although clearly distinguishing new provincial Cap-and-Trade programs from existing DSM programs should be the focus for regulators and government, Union recognizes that in some cases external programs may be commissioned in a way that competes with, or duplicates, an existing utility DSM program. Union has and will continue to partner its DSM programs with external programs wherever possible. However, in instances where a new provincial Cap-and-

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[66] http://www.ieso.ca/corporate-ieso/ministerial-directives
[67] Environmental Commissioner of Ontario, August 2017 - Annual Energy Conservation Progress Report 2016/2017 (Volume Two), p. 11.

Trade program is designed and implemented in a manner that makes it unfeasible for an existing DSM program to be successful (i.e. significantly hampers the utility's ability to drive participation in its existing DSM program due the design of the provincial Cap-and-Trade program), and a partnership agreement cannot be made, Union is requesting the ability to reallocate the OEB-approved budget and shareholder incentive opportunity from the DSM program and scorecard to other existing OEB-approved DSM programs and scorecards.[68] This ensures that the Utilities have adequate flexibility to respond and adapt to changes within the energy conservation landscape, and to shift focus away from duplicative programs and towards programs that better meet its customers' needs.

[68] For example, if Union were to reallocate 20% of the budget from the Resource Acquisition scorecard to the Low-Income scorecard, Union is requesting that 20% of the shareholder incentive opportunity is also reallocated from the Resource Acquisition scorecard to the Low-Income scorecard.

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Home Energy Management System – Bring Your Own Thermostat Pilot Program

Gas Evaluation Report: Volume I

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Opinion Dynamics

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Introduction

This is the first of two volumes that comprise the evaluation results of Hydro One Networks Inc. (Hydro One) Home Energy Management System -- Bring Your Own Thermostat (BYOT) Pilot Program Study. This volume contains key findings, results, and recommendations for the Pilot.

The second volume contains a set of appendices that document methods, approach, and findings, as well as data collection instruments.

1. Executive Summary

This report provides the results of the evaluation of Hydro One Networks Inc.'s (Hydro One) Home Energy Management System -- Bring Your Own Thermostat (BYOT) Pilot Program (Pilot). Hydro One designed the BYOT Pilot to assess demand response (DR) and energy efficiency (EE) impacts, time-of-use (TOU) bill impacts, and cost effectiveness, as well as process related insights and market interest in Wi-Fi-enabled programmable thermostats in support of building a future program.

In 2015, Hydro One, seeking to deliver cost-effective load reduction, piloted a residential DR program where customers who purchased a web-addressable smart thermostat of their choice were offered an incentive for participation in DR events. Three participating vendors—Nest, Honeywell, and EnergyHub—offered thermostats that can be remotely called to reduce load in response to utility events. The Pilot employed a BYOT delivery model, which uses vendor-driven marketing approaches to achieve customer enrollment needs. Vendors were able to recruit customers with an eligible thermostat model already installed into the Pilot (flippers), as well as new enrollees who purchased the device when they enrolled in the Pilot. The BYOT design allows customers to choose from 15 thermostat models providing varied load reduction strategies (such as different temperature offsets, cycling strategies, etc.). EnergyHub offered 10 thermostat models to customers, Honeywell offered 4 thermostat models, and Nest offered 1 thermostat model (with new firmware updates). The Pilot enrolled 1,440 participants, with substantial variation in total enrollment by vendor (136 EnergyHub, 318 Honeywell, and 986 Nest)[1], as well as by participant type (1,038 flipper and 398 new enrollees). Of these, 334 participants were also Union Gas customers, and reflected variation in enrollment by vendor (13 EnergyHub, 71 Honeywell, and 245 Nest)[2], as well as by participant type (234 flipper and 95 new).

Evaluation Approach

The evaluation effort focused on assessing gas and electric EE, DR and TOU bill impacts associated with the Pilot through a series of regression analyses based on customer billing information. The evaluation also included program manager and vendor interviews, a program and technology data review, and participant surveys to develop a complete understanding of each vendor delivery model, technology performance, and customer interest and satisfaction with the Pilot.

Evaluation Findings and Recommendations

Table 1 provides a summary of the impact results associated with this evaluation of the pilot. These include energy and bill savings.

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[1] Four Nest participants were not assigned as either flipper or new enrollee.

[2] 5 participants were removed from the analysis due to insufficient pre-period data.

Table 1. Summary of Impact Results from Pilot

Energy Savings	Unit	Participants in Model	Modeled Baseline Daily Usage	Per Participant Regression Estimated Treatment Effect			Standard Error	95% CI Daily Savings	
				Daily Savings	Annual Savings	% Savings		Lower	Upper
Gas	m^3	139	4.2	0.2	85	5.5%	0.12	0.01	0.48
Gas Bill Savings	**Annual Bill Savings**								
Bill Savings	$13								

The evaluation yielded a number of key findings central to questions of whether or not and how to implement a BYOT program in the future.

- **The Pilot delivered lower than anticipated gas savings.** The evaluation estimated a reduction of 5.5% of average annual gas consumption (or 0.2 cubic meters per day). These reductions resulted in customers saving an average of $13 annually on their gas bills from reducing usage.
- **Customer satisfaction and engagement with their smart thermostats is high**. Pilot participant survey respondents tended to be highly satisfied with their thermostat and the Pilot, and tended to feel more comfortable in their homes after installing the device. Most respondents also perceived their thermostat to be of excellent or very good value.
- **Around half of new enrollee Pilot participants would have paid full price for the thermostat.** There was variation across vendors in terms free ridership with purchasers of Nest and Honeywell devices having higher levels of free-ridership than purchasers of EnergyHub devices.

Based on these findings, we present the following strategies for successful program deployment.

Enhance Vendor Marketing Strategies

According to vendor interviews, Hydro One offered the Pilot during a short time frame and not all vendors leveraged all potential marketing channels. Further, the marketing strategies deployed by vendors have implications for EE free-ridership. For example, Nest's marketing strategy included providing an incentive for the device to hand-raiser customers (those who had requested to be on an internal Nest marketing list prior to the Pilot), who are particularly likely to be EE free-riders because these customers are more likely to have purchased the device without the incentive. Further, Pilot participants survey respondents tended to be highly educated, high-income customers who suggested in the survey that they would have purchased the device without the incentive.

- *Recommendation:* To support increased EE impacts, employ multiple and effective marketing strategies (such as point of sale retail rebates, or direct mail targeted to lower income customers that may reduce free ridership) for a longer period of time and consider vendor co-branding with the utility to support customer engagement and recognition. Marketing strategies should mitigate free ridership concerns while supporting enrollment objectives.

Refine Customer Targeting and Eligibility Criteria

Pilot participants tended to replace programmable thermostats as opposed to manual thermostats with smart thermostats, which studies suggest yields lower EE impacts than replacing a manual thermostat with a smart thermostat.

- *Recommendation:* Develop targeted eligibility criteria to maximize EE impacts. These include targeting customers who have manual thermostats (as opposed to programmable or smart thermostats); higher baseline consumption (particularly for the heating and cooling periods); and 12 months of pre-installation energy consumption data to support evaluation efforts.
- *Recommendation:* Leverage Union Gas' existing general population research to identify the volume of customers who meet these criteria, and assess whether Union Gas and selected vendors can effectively recruit targeted customers cost-effectively.

Offer Tiered Incentive Structures

EE free-ridership tended to be high for new enrollee Pilot participants (customers who purchased a device when enrolling in the Pilot). Importantly, flipper customers (customers who had already purchased a device prior to enrolling in the Pilot) were considered full EE free-riders for the BYOT Pilot because they had already purchased the device prior to the Pilot.

- *Recommendation:* For any EE focused program, exclude or offer a lower incentive to customers who have already requested a device through the vendors. In addition, to improve EE free ridership results, offer incentives to lower-income customers.

Balance Customer Engagement with Optimized EE Algorithms

Smart thermostats provide unique opportunities for customers to engage with their energy consumption, as well as their devices. However, as can be seen from the impact results, a potential explanation for lower than anticipated gas EE savings results may reflect differences in the way Pilot participants engaged with their thermostats and/or variations in the operation of the thermostat (e.g., each vendor has different algorithms that it employs to achieve EE impacts) across vendors. Our survey results show that Nest respondents were more likely to make adjustments to their thermostat, and with greater frequency, than were Honeywell or EnergyHub respondents. One could hypothesize that frequent adjustments, particularly to pre-programmed settings, would have implications on EE savings.

- *Consideration:* We recommend integrating customer self-reported engagement information (e.g., survey responses, logging into the app, setting features, etc.) with vendor supplied thermostat set point data to characterize participant thermostat engagement across vendors to better understand whether increased engagement dampens energy savings. This profile of engagement could also be applied to groups of energy efficiency savers – e.g., high, medium and low savers, to assess correlates between engagement and energy impacts by vendor.

Conclusion

Hydro One developed the BYOT Pilot to assess whether a full-fledged program would merit the costs of deployment. For any pilot effort, determining scalability must take Pilot results, additional context, sensitivity analyses, and other factors into account. In many cases, a pilot can differ from a program in terms of design and delivery, marketing and outreach strategy, and customer eligibility.

The results of this evaluation show that Pilot scalability and viability are dependent on future program goals (i.e. achieving DR or EE impacts). As a result, we present three considerations for moving forward with a BYOT roll-out:

- If Hydro One is interested in continuing to *combine both EE and DR impacts*, we recommend a more complex incentive and targeting approach (e.g., tiered incentives and targeting of high energy savings potential customers).
- If a future program focuses exclusively on *DR impacts*, we recommend recruiting flippers with a smaller participation incentive. If cost-effective, Hydro One could also consider offering an event participation incentive to new enrollees.
- If a future program focuses exclusively on *EE impacts*, we recommend excluding all flippers, who are free-riders, and targeting customers with the highest potential to save (who have manual thermostats) with the lowest levels of free-ridership (such as lower income customers who are less likely to purchase the device without an incentive).

2. Research Objectives and Methods

Below we provide the BYOT Pilot evaluation research objectives, research tasks, and evaluation limitations. Volume II provides detailed methodological approaches and results.

2.1 Research Objectives

We conducted a set of research tasks to provide findings and recommendations related to Pilot results and opportunities to scale the Pilot into a full-fledged program. Our evaluation effort addressed the following research tasks to provide:

1. *Insight into which vendors are delivering the greatest load reduction to inform thermostat model prioritization:* We conducted an impact evaluation to assess which vendors contribute the most in terms of load impact, as well as produce the largest energy savings. Notably, we present overall results only for gas customers because the low number of participants who were Union Gas customers made estimating separate effects by participant type or vendor impossible.

2. *Strategic assessment of Pilot marketing channels:* Given that the Pilot relied on vendors to recruit participants, our research efforts sought to understand the relative success of marketing strategies and channels, as well as assess which vendors are the most engaged and enroll the highest volume of optimal customers.[3]

3. *Perspective on the customer experience:* We designed and fielded three customer feedback surveys to generate insights on key aspects of the customer experience. These surveys gauged customers' comfort and satisfaction with the program, DR events, vendors, and thermostat models at varying times within the Pilot period.

4. *Assessment of Pilot scalability.* We synthesize findings and provide recommendations across the evaluation components to provide guidance and projections for a full-scale roll-out. We incorporate insights from the process evaluation efforts, as well as impact results, to provide recommendations regarding moving the Pilot to a program.

Figure 1 provides an overview of the key research questions for the evaluation effort.

Figure 1. Overview of Research Questions

Process	Impact
• How well does each marketing channel perform? • What levels of customer interest and satisfaction does the Pilot generate? • How well does each piloted thermostat model perform?	• What are the energy efficiency and utility bill savings? • What are the DR impacts?

[3] We define "optimal customers" as those customers who contribute the highest load reduction and/or energy impacts.

2.2 Research Tasks

As part of the evaluation, Opinion Dynamics conducted a series of research tasks. These are documented in Table 2.

Table 2. Summary of Evaluation Research Tasks

Research Area	Research Task
Process Evaluation	Program staff interviews
	Vendor interviews
	Review of marketing and enrollment data and vendor and technology data
	Participant surveys
Impact Evaluation	Power analysis
	Selection of matched comparison groups
	Modeling of gross and net energy savings, load, and bill shifts
	Experimental design and event day selection rules
	Modeling of ex ante and ex post DR impacts

We provide a brief summary of each of these tasks below.

2.2.1 Process Evaluation

The process evaluation assessed thermostat performance, participant enrollment and marketing channels, and customer responses to the thermostat model and to the Pilot. We conducted the following tasks.

Interviews with Program Staff and Vendors

At the beginning and end of the Pilot, we conducted interviews with relevant program managers and staff to obtain a detailed level of knowledge about the Pilot and its objectives, as well as results and opportunities for enhancement.

Because vendors were the primary implementation partners for the Pilot, we conducted three phased interviews with a representative from each of the three vendors. The first interview was conducted during the first phase of enrollment and collected information regarding objectives for the Pilot and on interactions between the vendor, Hydro One, and the participants. For the second interview, we focused on the vendor's experience with the customers, marketing approaches and channels used, and reviewed information, if any, that the vendors shared with customers after they enrolled in the program. In addition, we asked a series of questions regarding DR events and capabilities. At the close of the Pilot, we discussed challenges and opportunities associated with the Pilot.

Review of Marketing and Enrollment Data and Vendor and Technology Data

We reviewed marketing and enrollment data by vendor. We also reviewed vendor data related to thermostat model performance. Data include participant enrollment date, installation date, vendor, device type, participant type, device removal date, and vendor event participation reports.

Participant Surveys

Opinion Dynamics fielded three surveys via the internet to all program participants (census attempt). We conducted surveys in phases, the first survey conducted at or near the date of installation of the thermostat, the second survey immediately following a DR event or events, and the third at the close of the DR event season.

Survey Instruments

Each survey focused on different aspects of the Pilot. In the first survey, we asked questions covering household characteristics, enrollment and installation, and satisfaction with the incentive. Additionally, we asked about the type of equipment replaced by the smart thermostat, as well as about the level of engagement with the thermostat, and a series of free-ridership questions to get at whether the participant would have purchased the thermostat model without the incentive and other questions that provided additional nuance around motivation/intention to purchase the thermostat model. In the second survey, we focused on response to DR events (comfort levels, adjustments to settings, opting out of events). In the third survey, we incorporated many of the same questions from the first survey to assess any changes in satisfaction, engagement, and usage with the thermostat model.

Survey Sample Design and Response Rate

Opinion Dynamics fielded a survey to all BYOT Pilot participants using a census approach. Table 3 shows the total number of customers after we cleaned the data and the total number of calls made. The table also includes the total completes achieved, including commercial customers who have been excluded from our analysis, as well as response rates for each survey.

Table 3. Sample Frame and Response Rate

Survey	Population (N)	Sample Frame (N)	Total Respondents (n)	Response Rate	Respondents Excluding Commercial Customers (n)	Fielding Date
#1	1,440	1,424	1,147	81.46%	1,132	July 7 – August 4, 2015
#2[a]	1,440	1,418[b]	1,133	81.16%	1,120	September 3 – October 16, 2015
#3	1,440	1,401[b]	1,123	81.20%	1,109	December 8 – December 28, 2015

[a] We fielded the second Participant Survey for two separate event days and combined completes across those two fielding periods.
[b] Lower population of respondents given deactivation of devices.

In Survey #1, we reached 1,424 customers to obtain 1,147 completed interviews. We achieved a similarly high number of respondents for the subsequent surveys. Fewer than 1% of the participants could not be reached because their email bounced back, and fewer than 1% of participants were found to be ineligible for the survey across all three surveys. The survey response rate is the number of completed interviews divided by the total number of potentially eligible respondents in the sample. We calculated the response rate using the standards and formulas set forth by the American Association for Public Opinion Research (AAPOR).[4] Additional details about the survey response rates are in Volume II.

2.2.2 Impact Evaluation

Opinion Dynamics developed a series of evaluation approaches to assess key objectives, including DR impacts, energy savings, bill savings, and enrollment achievements. For DR impacts, we developed a randomized control trial (RCT) experimental design to assess these impacts with the highest level of rigor. To estimate energy impacts, we considered using a randomized encouragement design (RED) experiment but rejected the approach given the associated cost and difficulty enrolling sufficient customers within the program. Based on the implementation of the program, Opinion Dynamics developed a matched comparison group approach to estimate energy impacts. This design leverages a matched comparison group or pre-post analysis of usage data to estimate impacts and both methods align with Independent Electricity System Operator (IESO) protocols. We developed a matched comparison group as our preferred approach to determine impacts, as this approach is preferred because it reduces potential for bias while improving precision over other quasi-experimental designs. See Volume II for more details regarding the methodological approach.

Energy Efficiency Impacts

In this section, we outline our approach to calculating energy savings (both gas and electric), as well as utility bill savings. Our results differentiate net energy impacts and load shifting impact on demand results by vendor, participant, and region, where relevant. We conducted the following research tasks.

Power Analysis

We conducted a power analysis to determine the sufficient number of enrollments required to estimate energy savings impacts for each vendor. Upon conducting the power analysis, we provided Hydro One with the total number of participants required for the load analysis so that we have information in advance about the potential to identify savings if present.

Selection of Matched Comparison Groups

Matched comparison groups are the quasi-experimental analogue to control groups in a RCT, in that they serve to establish the "counterfactual," or participants' baseline usage in the absence of a pilot. A matched comparison group helps correct for omitted variable bias, where unmeasured variables (e.g., macroeconomic indicators, household size) have an impact on electricity consumption. For this reason, the comparison groups must be as similar as possible to the participants with respect to energy consumption during the pre-Pilot period so that we can be confident that the behavior and electricity consumption of the comparison group during the Pilot period provides an accurate reflection of participant behavior and usage in the absence of the Pilot. We document our matching methodology in detail in Volume II.

Regression Analysis to Determine Both Net Program Energy Impacts and Load Shift Impacts

We conducted an analysis to assess changes in energy consumption attributable to the BYOT Pilot. We relied on a statistical analysis of hourly electric Advanced Metering Infrastructure (AMI) data for Hydro One

[4] *Standard Definitions: Final Dispositions of Case Codes and Outcome Rates for Surveys*, AAPOR, 2011. http://www.aapor.org/AM/Template.cfm?Section=Standard_Definitions2&Template=/CM/ContentDisplay.cfm&ContentID=3156.

customers who purchased a smart thermostat and enrolled in the program (the new enrollees) and monthly gas usage data from Union Gas. Opinion Dynamics estimated electricity savings for the average participant in the program and for the average participant by vendor. Additionally, we produced estimates by participant type (i.e., flipper[5] and new enrollee). Furthermore, we estimated "permanent" load shift, where participants move energy-intensive tasks from peak hours to off-peak hours to save money on their bill as a result of interaction with the program and the smart thermostat model. The load shift estimates are required to calculate electric bill savings because nearly all of the residential customers in Hydro One territory are on a time-of-use (TOU) rate.

Calculation of Free-Ridership for Program Scalability

The estimating approach described above provides net energy impacts using a comparison group. In this respect, the regression model will provide net impacts that account for free ridership and participant spillover for the Pilot. However, we incorporated questions within the participant survey to assess levels of free ridership asking whether the participant would have purchased the thermostat model without the incentive (new recruits), and other questions that provide additional nuances around motivations/intention to purchase the thermostat model (flippers). Notably, we assume that flippers are free riders, i.e., they purchased the smart thermostat without the incentive, while new recruits may have varying levels of free ridership. These results provide insights into program scalability and potential impacts for a full roll-out.

Estimation of Utility Bill Savings

To calculate electricity bill savings, we consider both electric savings and load shift from peak to off-peak periods. We designed our electric energy savings analysis to deliver overall electric savings and load shift results to support utility bill savings analysis. From the 'permanent' load shift results, we calculated bill savings by multiplying energy savings within each of the three TOU periods by their respective rates. To calculate gas bill savings, we use the results of the gas energy savings analysis and calculate bill savings by multiplying gas savings by the average rate that participants pay for their last cubic meter of gas.

Demand Response Modeling

The primary objective of the DR modeling activity was to measure the DR impacts of the Pilot. To accomplish this, we estimated ex ante demand savings for each vendor for each region for 1-in-10 weather years' monthly system peak days as well as ex post demand savings for each event for each vendor and for each region within vendor. We used a difference-in-difference (DID) model for ex post estimates and linear regression models based on the ex post models for ex ante estimates. The modeling approach is consistent with the Independent Electricity System Operator (formerly Ontario Power Authority) Load Management protocol.[6]

[5] A "flipper" is a customer who had already purchased a device prior to enrolling in the pilot and a "new enrollee" is a customer who purchased a device when enrolling in the pilot.

[6] http://www.ieso.ca/Documents/conservation/LDC-Toolkit/EM%26V-Protocols-and-Requirements-10312014.pdf

Experimental Design

For this pilot program, where the focus is on accurate and defensible impact estimates rather than overall program savings, we used the best method to estimate the treatment effect[7]. We developed a RCT for DR impacts of events called during the peak summer period of 2015. In this approach, some enrolled customers served as a control group and did not participate in a DR load control event. Treatment assignment for each vendor is shown in Table 4, with one-quarter of the participants assigned to each group. In each event, the treated half had an event called and the other half served as a control group.

Table 4. Group Assignment for Each Vendor

	Group			
Event	A	B	C	D
1	Treatment	Control	Treatment	Control
2	Treatment	Control	Control	Treatment
3	Control	Treatment	Control	Treatment
4	Control	Treatment	Treatment	Control
5	Treatment	Control	Treatment	Control
6	Treatment	Control	Control	Treatment
7	Control	Treatment	Control	Treatment
8	Control	Treatment	Treatment	Control
9	Treatment	Control	Treatment	Control
10	Treatment	Control	Control	Treatment

Hydro One called events based on the following criteria:

- IESO system-wide events - Call events for all IESO primary and secondary trigger system-wide events
- *peaksaver* PLUS Evaluation Measurement & Verification (EM&V) events - Call events during *peaksaver* PLUS EM&V events to allow for comparison of the DR impact of the BYOT Pilot against that of the *peaksaver* PLUS program
- Pilot events - Call events for a variety of temperatures, months, days of the week, and event windows, where feasible

Ex Post Demand Response Modeling

Opinion Dynamics used a DID modeling approach for the demand impact analysis. The RCT design allows for a simple model. Because customers were randomly assigned into treatment and control groups, the average control group usage during the event is a valid counterfactual baseline for what the treatment group's usage would have been had they not been selected to participate. As a result, we can calculate savings simply by subtracting average hourly treatment group usage from control group usage during each event hour.

[7] The RCT approach to DR impacts requires that, in this case, half of the participant's act as a control group for each of the demand response events. This is a trade-off between maximizing total DR impact and making accurate, unbiased estimates of per-participant DR impacts.

Both non-participant spillover and structural benefiters are assumed to be zero for DR ex post and ex ante impacts. For non-participant spillover, customers are not expected to reduce consumption during events without an incentive, smart thermostat, or event trigger. Structural benefiters are those who are better off when enrolled in the program due to their load profile, but the requirement that participants have central AC, and the fact that the thermostat controls the AC during the events, means that participants have to explicitly opt-out of the event, or the load reduction will occur.

Ex Ante Demand Response Modeling

Opinion Dynamics used data from the ex post evaluation to build ex ante regression models predicting demand savings for each hour of an event window for the cooling season system peak day for a 1-in-10 weather year, as provided by Hydro One. Ex ante models predict future DR impacts for peak months. Opinion Dynamics used a linear random-effects regression (LRER) modeling approach for the ex ante demand impact analysis. This model is very similar to linear fixed-effects regression (LFER) in that it takes time-invariant, household-level factors affecting energy use into account without measuring those (often immeasurable) factors directly. It is often preferred to LFER for predictive tasks because it takes variation between individuals into account when producing estimates.

2.3 Limitations

All evaluations have some limitations and sources of error that affect interpretation of evaluation results. Understanding the uncertainty (sources of error) and internal and external validity of the evaluation is necessary for making informed decisions based on evaluation results.

Table 5 provides a summary of possible sources of error associated with data collection conducted for the Hydro One BYOT evaluation. We discuss each item in detail below.

Table 5. Possible Sources of Error

Research Task	Survey Error		Non-Survey Error[3]
	Sampling Error[1]	Non-Sampling Error[2]	
Participant Surveys	• Sample frame error • Sampling error • Coverage error	• Measurement error • Non-response error	n/a
Billing Analysis	n/a	n/a	• Model specification error • Measurement error • Multi-collinearity • Heteroskedasticity • Serial correlation

We took a number of steps to mitigate against potential sources of error throughout the planning and implementation of the evaluation.

Survey Errors

1. **Sampling Error:**

- **The surveys contained no sampling errors:** There is no sample frame error because we fielded a survey to all participants with an email address, which reflects all of the customers in the program. There is no sampling error because we conducted a census for all surveys. Further, there is no coverage error (e.g., when a sample frame excludes a portion of the population) because all Pilot participants were surveyed.

2. Non-Sampling Errors:

- **Measurement errors**: We addressed the validity and reliability of quantitative data through multiple strategies. First, we relied on our experience to create questions that measure the ideas or constructs that are of interest and that have demonstrated predictive power in past studies. We reviewed the questions to ensure that we did not ask double-barreled questions (i.e., questions that ask about two subjects, but with only one response possibility) or loaded questions (i.e., questions that are slanted one way or the other). Key members of Opinion Dynamics, as well as Hydro One staff members, had the opportunity to review the survey instrument. There will always be some degree of measurement error because different respondents will interpret questions differently or recall things differently. However, after addressing the major forms of non-random errors as described above, the rest of the measurement error is likely to be randomly distributed, and thus would not contribute to biased results.

- **Non-response errors:** This type of error is most likely to produce the biggest threat to external validity. That is, customers who are willing to complete a survey may be systematically different from those who are not. Overall, the distributions of average daily kWh consumption were similar for the respondents and non-respondents across vendors, with the variation in average consumption slightly higher for non-respondents. Plots by survey for the three surveys reflect similar characteristics. On the whole, these differences do not undermine the validity of our comparison vendor responses.

Non-Survey Errors

3. Analysis Errors: Impact Evaluation

- **Model specification errors:** The most difficult type of modeling error, in terms of bias and the ability to mitigate it, is specification error. With this type of error, variables that predict model outcomes are included when they should not be, thus reducing the precision of the results, or left out when they should be included, possibly producing biased estimates. The team addressed this type of error two ways: first, by using a two-way fixed-effects model with customer-specific intercept that corrects for all time invariant customer characteristics and with a time-specific fixed effect that corrects for all outside influences that affect all customers similarly, and second, by testing a variety of model specifications to find the simplest model that effectively balances bias reduction and accuracy.

- **Measurement errors:** Measurement error can come from variables, such as weather data, which are commonly included in the billing analysis models. If a base temperature that does not reflect actual home characteristics is chosen for calculating degree-days or if an incorrect climate zone weather station is chosen, the model results could be subject to measurement error. We addressed this type of error by carefully choosing the closest weather station for each customer in the model.

  Specifying an incorrect time stamp (either pre-treatment or post-treatment) can also lead to measurement error. To the extent that the data received from the program implementer are correct, this should not be a problem, and we performed thorough checks to try to find any issues such as scaling factors that affect some time periods differently than others.

- **Multi-collinearity:** This type of modeling error can both bias the model results and produce very large variances in the results. The team dealt with this type of error by using model diagnostics such as VIF (Variance Inflation Factor), though the relatively simple models used in the impact analysis have essentially no chance of problems with multi-collinearity.

- **Heteroskedasticity:** This type of modeling error can result in imprecise model results due to variance changing across customers with different levels of consumption. The team addressed this type of error by using robust standard errors. Most statistical packages offer a robust standard error option and make conservative assumptions in calculating the errors, which has the effect of making significance tests conservative as well.

- **Serial correlation:** This type of modeling error is due to correlation of multiple sequential observations within each customer. This can result in too small standard error estimates, but no difference in impact model results. The team assessed this type of error by checking autocorrelation and modeling on different time scales, and chose the usual estimate of standard error.

Internal validity is the ability to estimate correct impacts of a pilot given the Pilot design. Threats to internal validity include **selection bias**, where the control (or comparison) group is not equivalent to the treatment group; **spillover**, where there is a treatment effect on control group; and **confounding**, where the change in energy usage is due to causes other than the treatment, such as changes in equipment.

External validity is the ability to generalize from the evaluation of a pilot to a full program. Pilot programs are always different from full programs, so drawing conclusions from the pilot to the full program requires consideration of how the full program will differ from the pilot and whether those differences are relevant. For instance, the external validity of the energy efficiency savings and DR impacts is limited because of the group of customers who enrolled in the Pilot. For example, conversations with Nest suggest that non-enrolled customers with a device have higher average run-time than those who opted-in to the pilot. These customers may not use energy the same way, and may be more energy conscious than customers who enroll in a future program. These differences could arise for several reasons, including marketing approach, incentive structure, choice of vendors, and early technology adoption of Wi-Fi-enabled thermostats among Pilot participants. We address these and other differences as part of the future program design discussion in Section 6.

3. Pilot Description

In 2015, Hydro One, seeking to deliver cost-effective load reduction, piloted a residential DR program where customers who purchased a web-addressable smart thermostat of their choice were offered an incentive for participating in DR events. Three participating vendors—Nest, Honeywell, and EnergyHub—offered thermostats that can be remotely called to reduce load in response to utility events. Hydro One designed the BYOT Pilot to assess DR, energy efficiency impacts, bill savings, and market interest in Wi-Fi-enabled programmable thermostats. The Pilot employed a BYOT delivery model, which uses vendor-driven marketing approaches to achieve customer enrollment needs. In addition, the program offered customers who had an existing Wi-Fi-enabled thermostat (flippers) an incentive for participating in DR events.

3.1 Pilot Design and Devices

The BYOT approach means that customers can choose from 15 thermostat models providing varied load reduction strategies (such as different temperature offsets, cycling strategies, etc.). EnergyHub offered 10 thermostat models to customers, Honeywell offered 4 thermostat models, and Nest offered 1 thermostat model (with new firmware updates). Table 6 provides a list of the BYOT Pilot thermostat models by vendor and participating company.

Table 6. List of BYOT Pilot Thermostat Models

Vendor	Participating Company	Thermostat Model
EnergyHub	Alarm.com/Vivint	Radio Thermostat CT-100 Radio Thermostat CT-80 Radio Thermostat CT-30 Trane Home Energy Management Thermostat
	American Standard	AccuLink Platinum ZV Control Silver XM Control AccuLink Control
	Ecobee	Smart Thermostat Smart SI
	Radio Thermostat	3M-50 CT-30 CT-50 CT-80
	Trane	Home Energy Management Thermostat ComfortLink II XL 950 Control XL 624 Control
Honeywell	Honeywell	Wi-Fi 9000 Wi-Fi VisionPRO Wi-Fi FocusPRO Lyric
Nest	Nest	Nest Learning Thermostat

Vendors encouraged customers to sign up their existing or newly purchased prequalified thermostats in the program in exchange for an incentive of $100 per thermostat. Vendors conducted most of the marketing to customers, while Hydro One also sent an “e-blast” to eligible customers with an eAccount (approximately

100,000 customers).[8] The enrollment period for the Pilot was from December 15, 2014 through May 4, 2015. Hydro One enrolled 1,440 participants in the Pilot.[9] Vendors recruited customers with a prequalified thermostat model already installed into the Pilot ("flippers"). Vendors were tasked with enrolling a minimum of 200 participants in the Pilot, 100 of whom must be new recruits (i.e., had not yet purchased a thermostat). Nest was the only vendor who achieved both enrollment goals.

Hydro One required that participants should be Hydro One customers, have central air conditioning systems, have installed one of the pre-approved Wi-Fi-enabled thermostats not earlier than October 1, 2013, have had their program-eligible thermostats connected to the internet, and have sufficient pre-Pilot customer billing data. In addition to Hydro One's requirements, Nest required participants to have Nest accounts. Overall, the vast majority of recruited customers satisfied eligibility criteria, although there were some customers who had insufficient pre-Pilot customer billing data, some that did not have a central air conditioning systems, and others who were commercial customers (rather than residential customers).

3.2 Pilot Recruitment and Participant Characteristics

Vendors were able to recruit customers with an eligible thermostat model already installed into the Pilot (flippers),[10] as well as new enrollees who purchased the device when they enrolled in the Pilot. The Pilot enrolled 1,440 participants, with substantial variation in total enrollment by vendor, as well as by participant type.

Table 7. BYOT Pilot Enrollment

Vendor	Flipper	New Enrollee	Total
EnergyHub	87	49	136
Honeywell	238	80	318
Nest	713	269	986[a]
Total	**1,038**	**398**	**1,440[a]**

[a] Note that four Nest participants were not assigned as either flipper or new enrollee.
Source: Participant file shared by Hydro One in October 2015.

Customers tended to be concentrated in the following geographic areas (Figure 2 and Figure 3).

[8] Hydro One identified customers for whom they have complete meter data for 14 months prior to the Pilot start.

[9] One participant signed up after the enrollment period in July 2015, but was excluded from DR and participant survey efforts.

[10] Notably, flippers must have purchased the thermostat model after October 2013 to provide sufficient usage history to estimate impacts.

Figure 2. Map of BYOT Pilot Participants in Hydro One Territory by Vendor

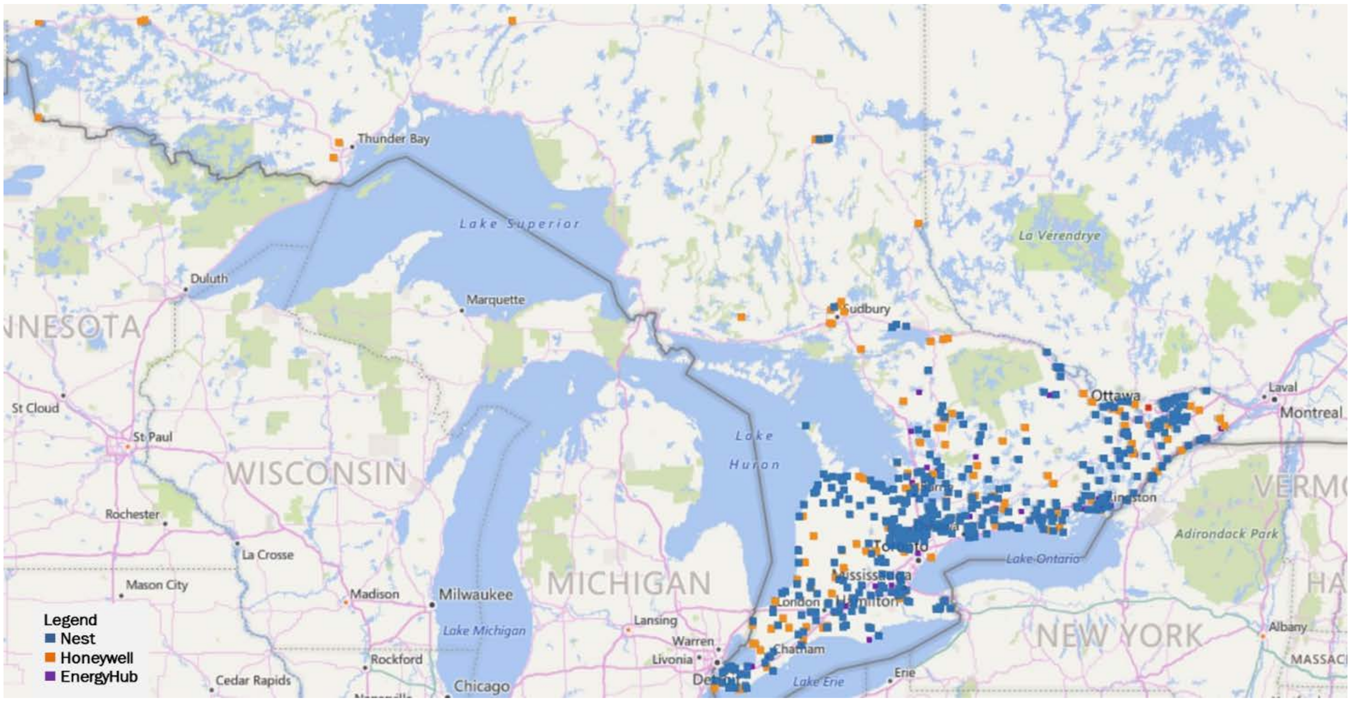
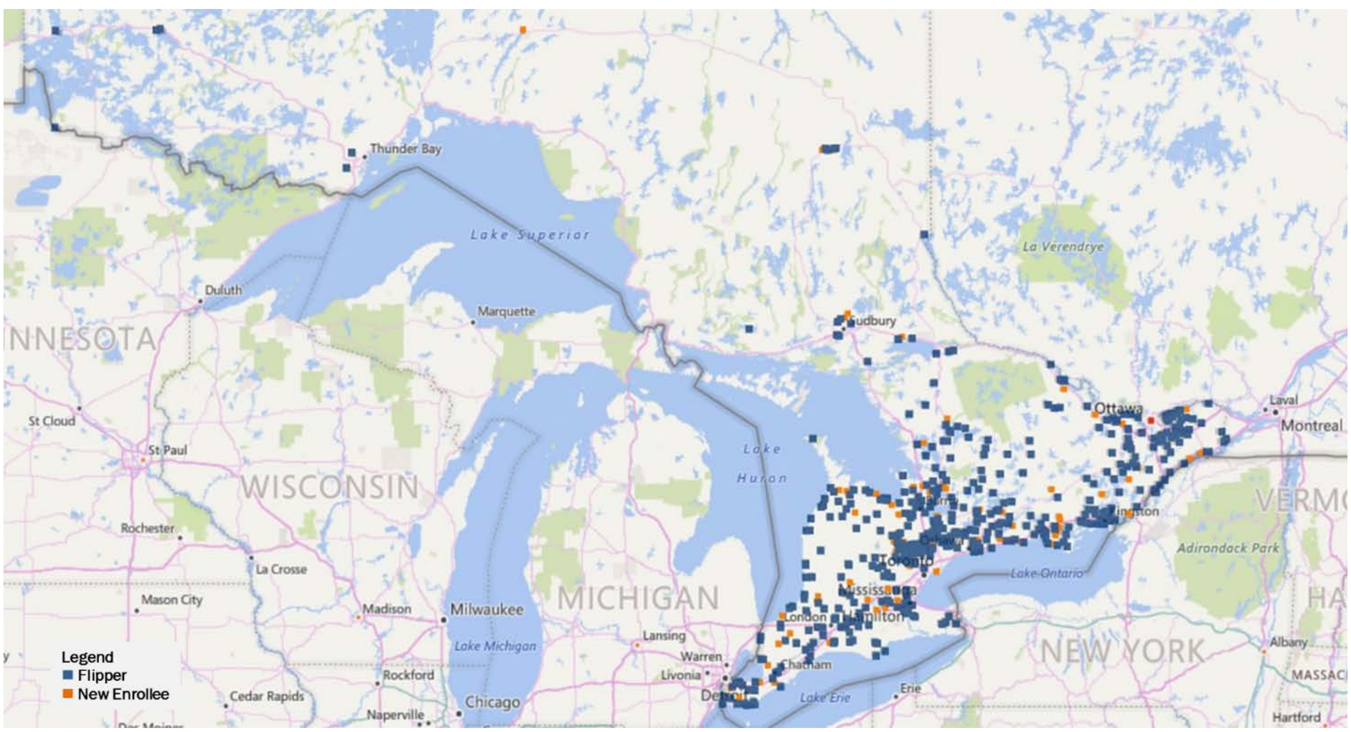
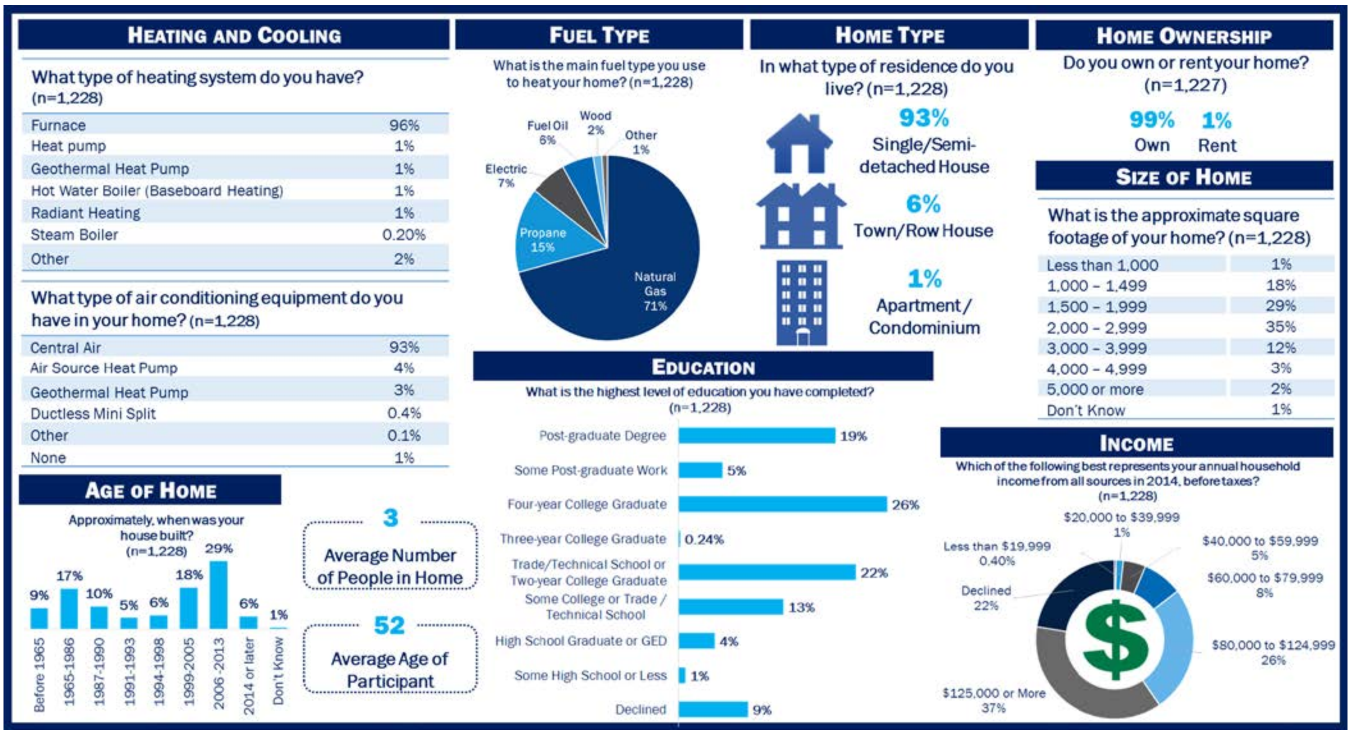


Figure 3. Map of BYOT Pilot Participants in Hydro One Territory by Respondent Type



We found few differences between participant type regarding household and demographic characteristics based on responses to our surveys. Survey respondent demographics and household characteristics were generally similar, with some variation by vendor. EnergyHub respondents were less likely to have central air conditioning equipment or natural gas as their primary heating fuel type compared to Honeywell and Nest.[11] This is surprising given that having a central air conditioning unit was one criteria used to determine eligibility for the Pilot. In terms of demographics, Honeywell customers tended to have less education and lower annual income than EnergyHub and Nest.

Figure 4. Survey Respondent Demographic and Household Characteristics of Pilot Participants



Source: Participant Surveys 1, 2, and 3.

11 EnergyHub respondents were less likely to have central air conditioning equipment (76% of respondents) compared to Honeywell (91%) and Nest (95%). These respondents were also less likely to have natural gas as their primary heating fuel type (Energy Hub = 53%, Honeywell = 62%, and Nest = 76%).

4. Impact Evaluation Findings

We conducted a series of analyses to estimate EE and utility bill savings, as well as DR impacts. Opinion Dynamics developed a series of evaluation approaches to measure Pilot effectiveness to assess these key objectives, including DR impacts, energy savings, bill savings, and enrollment achievements.

4.1 Energy Efficiency and Utility Bill Impacts

To estimate energy impacts, we considered using an experimental design (RED), but rejected the approach given the associated cost and difficulty enrolling sufficient customers for the Pilot. Based on the implementation of the program, Opinion Dynamics developed a quasi-experimental, matched comparison group, approach to estimate energy impacts. This design leverages a matched comparison group and pre-post analysis of usage data to estimate impacts and aligns with IESO protocols. We chose a matched comparison group design over a pre-post design since matched comparison group designs better adjust for external factors. Once our comparison group was developed, we estimated energy impacts, testing a variety of different model specifications. We ultimately selected a linear two-way fixed-effects model that incorporated weather terms in addition to customer and period fixed effects.

Our team validated results across multiple model specifications, as well as matched comparison groups. These results remained stable and are not sensitive to model specification. We chose the matching method with the best balance between participants and comparison customers, so the results do degrade slightly with matching methods that yield poorer balance. We also conducted rigorous quality assurance and quality control on the underlying data to ensure that there were no issues with data cleaning or aggregation of results.

Overall, we found that:

- Pilot energy savings were 5.5% of annual gas consumption (or 0.2 cubic meters per day)
- Customers saved $13 on their gas bills from reducing consumption

4.1.1 Gas Savings

Energy Savings Impacts

Below we provide our overall gas savings results based on a quasi-experimental design using a matched comparison group. Overall, we found that the 334 BYOT Pilot participants who were also Union Gas customers saved 0.2 cubic meters per day for a 5.5% annual savings. The average annual bill savings was $13 per year for Union Gas customers. These results reflect 34,013 cubic meter savings for Union Gas and Hydro One Pilot participants during the Pilot period. Notably, we present overall results only for gas customers because the low number of participants who were Union Gas customers made estimating separate effects by participant type or vendor impossible.

Table 8. Overall Annual Gas Energy Savings Estimates

Group	Customers in Model	Modeled Baseline Daily Usage (m^3)	Annual Bill Savings ($)	Per Participant Regression Estimated Treatment Effect			Standard Error	95% CI Daily Savings	
				Daily m^3 Savings	Annual m^3 Savings	% Savings		Lower (m^3)	Upper (m^3)
Overall	139	4.2	13	0.2	85	5.5%	0.12	0.01	0.48

5. Process Evaluation Findings

We conducted a series of data collection activities to better understand Pilot delivery mechanisms and opportunities for enhancement. The process evaluation assessed thermostat performance, participant enrollment and marketing channels, and customer response to the thermostat model and Pilot. Opinion Dynamics fielded three surveys via the internet to all program participants. Surveys were conducted in phases, the first being conducted at or near the date of installation of the thermostat, the second immediately following a DR event, and the third at the close of the DR event season. These data collection efforts sought to address the following research questions: How well did each marketing channel perform? How well did each piloted thermostat model perform? What levels of customer interest and satisfaction did the Pilot generate?

5.1 Delivery Channel and Marketing Effectiveness

Each vendor employed a diverse range of marketing strategies to enroll at a minimum 200 participants in the Pilot. Notably, Nest was the only vendor who was able to recruit and enroll the minimum requirement. All vendors suggested that a future program could benefit from adjustments to their marketing strategies, including extending the period of time that the program was offered, leveraging more marketing channels (such as retailer point-of-sale offerings), and co-branding the program with Hydro One. Vendors enrolled fairly similar customers in terms of household and demographic characteristics, in addition to energy consumption.

Enrollment Volume

Vendors were tasked with enrolling a minimum of 200 participants in the Pilot, 100 of whom were to be new enrollees (i.e., people who had not yet purchased a smart thermostat). In total, there were 1,440 unique participants. Each participant fell into one of two categories: flippers, who were existing Hydro One customers who owned smart thermostats prior to participating in the Pilot, and new enrollees, who were customers who purchased smart thermostats as part of Pilot participation. Notably, Nest was the only vendor that achieved both enrollment goals. Table 9 provides a list of the BYOT Pilot thermostat models by vendor and enrollment by participant type.

Table 9. BYOT Pilot Thermostat Vendors and Enrollment Achievements

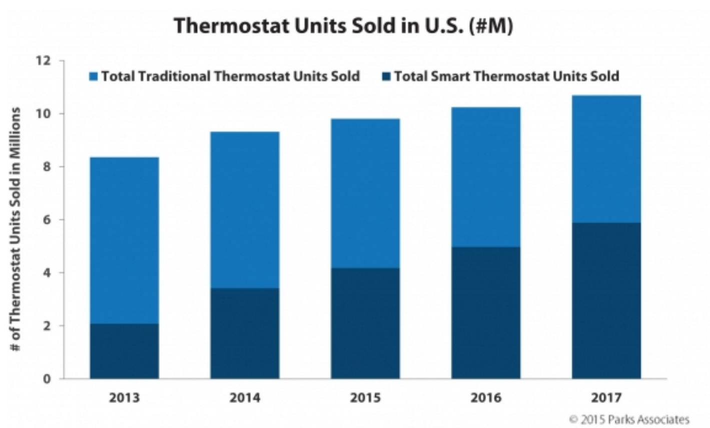
Vendor	Flipper	New Enrollee	Total	% of Total Enrollment Goal Achieved	% of New Enrollee Goal Achieved
EnergyHub	87	49	136	68%	49%
Honeywell	238	80	318	159%	80%
Nest[a]	713	269	986	493%	269%
Total	**1,038**	**398**	**1,440**	**66%**	**72%**

[a] Note that four Nest participants were not assigned as either flipper or new enrollee.
Source: Participant file shared by Hydro One in October 2015.

Recruitment Conversion

Market research indicates that smart thermostats "constitute the next generation of home automation devices that form a significant part of smart homes."[12] The global smart thermostat market size is expected to exceed 40 million units by 2022. Global revenue for communicating and smart thermostats, as well as associated software and services, could grow from US$146.9 million in 2014 to US$2.3 billion in 2023.[13] Google Nest, Honeywell, and Ecobee account for over 40% of the global smart thermostat market share in 2014.[14] By the end of 2016, nearly half of all thermostats sold will be smart thermostats, according to research from Parks Associates.[15]

Figure 5. Thermostat Units Sold in United States (2013-2017)



However, vendors suggested that awareness of devices is still fairly low, as the market is, as one vendor said during an interview, "moving from an early adopter to mass-market stage." According to Nest, it currently has a 1%–2% penetration rate of devices, but expects significant uptake. EnergyHub indicated constant growth in its marketing group as it partners with more end-use providers. According to Honeywell, when considering the size of the market, it assumes that about 78%–80% of homes have Wi-Fi, meaning they are eligible. However, vendors indicated that capturing these customers is difficult, and relies upon on marketing the value of the device to the customer.

Vendors also suggested that there were challenges associated with deploying marketing strategies during the Pilot. These included a shorter recruitment period of 3-4 months during a time frame when customers typically do not purchase thermostats. In addition, vendors acknowledged that there may be some hesitancy for customers to purchase a new technology. Further, vendors reported that they had difficulty identifying and verifying Hydro One customers. Vendors suggested employing multiple and various channels for marketing the program over a longer period of time, increasing incentive levels, and co-branding with the utility to increase customer awareness and acceptance of the devices.

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12 http://www.grandviewresearch.com/industry-analysis/smart-thermostat-market
13 http://www.electricalindustry.ca/latest-news/1531-report-forecasts-explosive-growth-in-markets-for-communicating-smart-thermostats
14 Ibid.
15 http://www.greentechmedia.com/articles/read/smart-thermostats-start-to-dominate-the-market-in-2015. The article does not provide a definition for Smart thermostats, but we asume this includes Wi-Fi programable thermostats.

Likelihood of Contributing to Demand, Energy or Bill Savings

One important feature of recruiting customers is the type of equipment that is replaced. Studies suggest that replacing a manual thermostat yields higher energy impacts than replacing a programmable thermostat.[16] Survey respondents typically replaced smart or programmable thermostats (70%). There was little variation across vendors. However, flippers tended to replace manual thermostats at a higher rate than new enrollees (27% to 15%, respectively).

5.2 Technology Performance

Most survey respondents found the thermostat installation process to be easy with limited challenges.

Ease of Installation

Most (86%) participants installed the smart thermostats themselves or by a family member; the rest were installed by a contractor (~13%) or by the vendor (<1%). Of the participants who installed the thermostats, a majority (86%) found installation easy. Among the participants who installed the device themselves, 67% of Nest, 42% of Honeywell, and 47% of EnergyHub users found their devices "very easy" to install. A few participants (21%) experienced challenges while installing their smart thermostat. Challenges included issues with missing wiring, Wi-Fi connectivity, and receiving defective devices.

5.3 Customer Engagement and Satisfaction

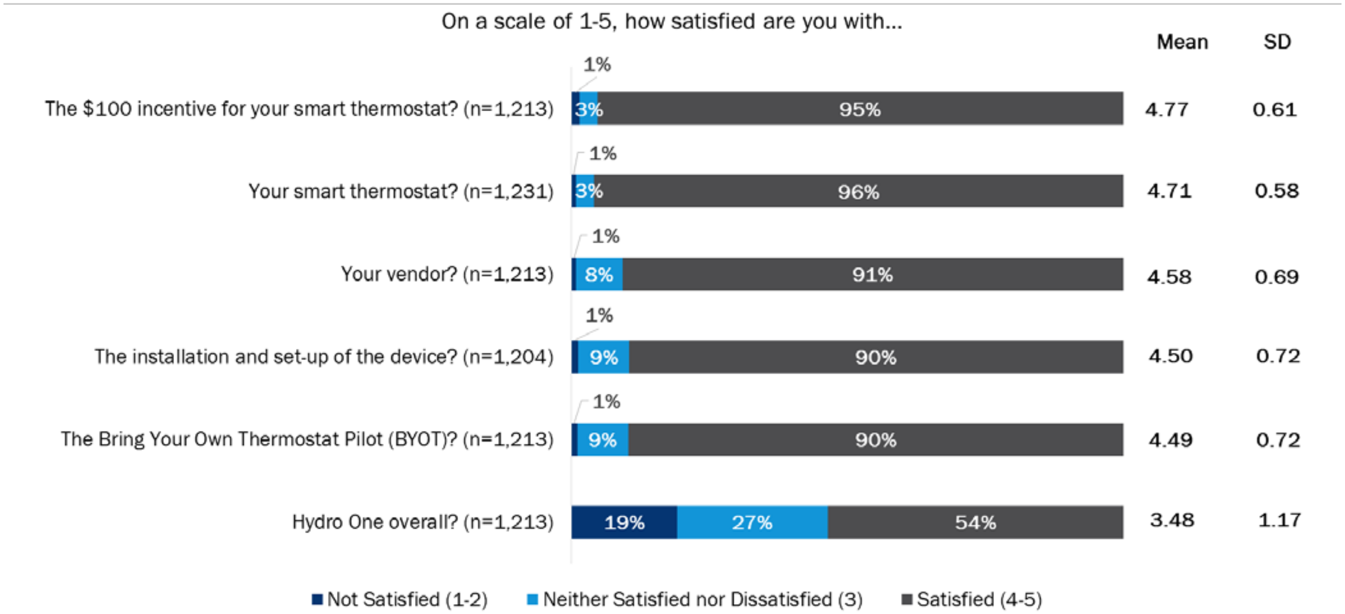
Pilot survey respondents were very satisfied with the Pilot, their device, and the incentive offered. Most respondents indicated that the thermostats increased their home comfort and valued the device highly. Additionally, customers tended to engage with their devices on a frequent basis, particularly Nest respondents.

Participant Satisfaction

Respondents were satisfied with the various aspects of the program, especially the incentive and device itself. Satisfaction rates did not vary substantially across vendors.

[16] A review of existing research indicates that there are minimal energy efficiency savings associated with smart thermostats if they replace programmable thermostats. For example, two studies conducted in Indiana suggest that the smart thermostats evaluated saved approximately the same as the programmable thermostats, both in terms of percentage of cooling electric usage and percentage of total electric usage. Cadmus, "Evaluation of the 2013-2014 Programmable and Smart Thermostat Program," Prepared for Vectren, January 2015. http://www.cadmusgroup.com/wp-content/uploads/2015/06/Cadmus_Vectren_Nest_Report_Jan2015.pdf? submissionGuid=7cbc76e9-41bf-459a-94f5-2b13f74c4e52.

Figure 6. Satisfaction Scores Overall

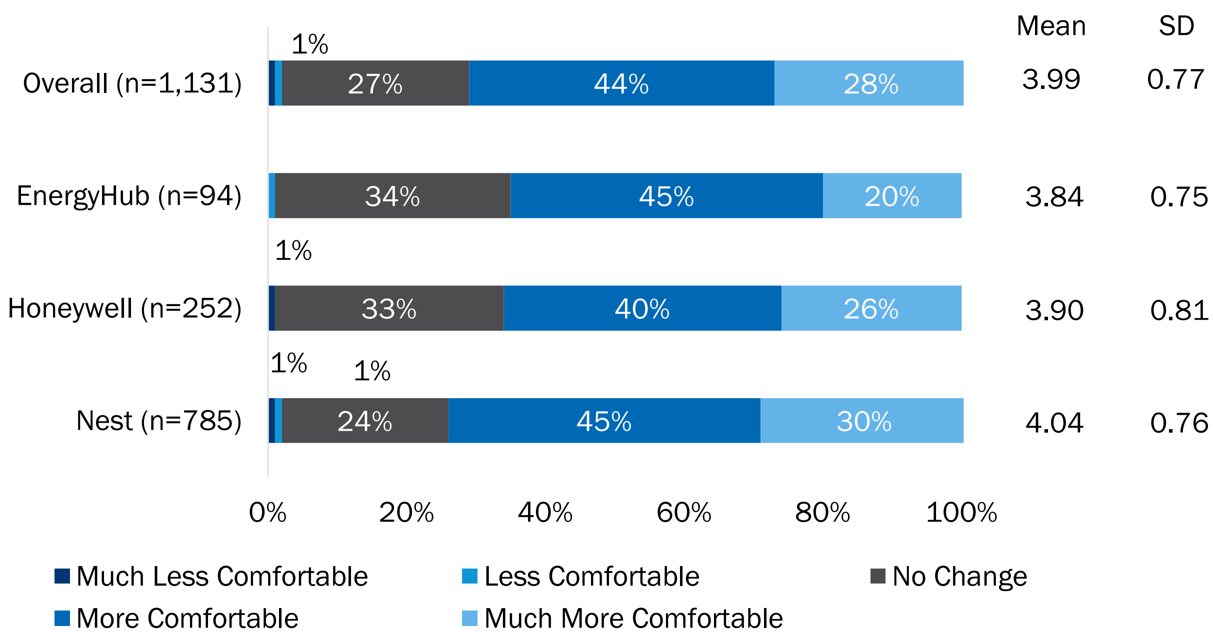


Source: Participant Surveys 1, 2, and 3.

Customer Comfort

Overall, most respondents said that they were more comfortable since installing their smart thermostats.

Figure 7. Respondent Comfort with Device, by Vendor (n= 1,131)



Source: Participant Survey 1.

Customer Engagement with the Device

Survey respondents adjusted their devices with moderate frequency. Nest participants were more likely to adjust their thermostat once a day or a few times a week than Honeywell. New enrollees make adjustments more frequently than flippers. Almost two thirds (65%) of new enrollee respondents had changed their device's pre-programmed settings, with EnergyHub owners (78%) more likely to do so than Nest device owners (66%). Our survey results indicated that Nest respondents were more likely to make adjustments to their thermostat, and with greater frequency than Honeywell or EnergyHub respondents. One could hypothesize that frequent adjustments, particularly to pre-programmed settings, could have implications on energy usage and energy savings.

Perceived Value of the Device

Survey respondents expressed a perception that their thermostat was of excellent or very good value. Nest respondents were more likely than their EnergyHub counterparts to believe that their device provides them with excellent value. More than half (54%) of new enrollee respondents would have paid full price for the smart thermostat without the $100 incentive. Nest respondents (58%) were more likely to have paid full price for the thermostat than EnergyHub respondents (40%).

6. Insights for Future Program Design

While this evaluation provides results for a specific group of Pilot participants, future participants can differ, particularly if Hydro One makes adjustments to their program design or delivery. As a result, this section outlines key considerations and recommendations related to pilot scalability and future program design.

6.1 Key Pilot Features That Inform Future Program Viability

There are a number of design features that affect the viability of the BYOT program moving forward including EE and DR impacts, customer bill savings and other benefits, and market adoption. Participant free-ridership and willingness to pay for smart thermostats are also key considerations. Below, we summarize results associated with each of these key features.

- **Energy Efficiency Savings:** Overall average gas EE savings for Pilot participants were 5.5% of annual gas consumption (or 0.2 cubic meters per day).

- **Customer Bill Savings and Perceived Value:** Union Gas customers saved an average of $13 annually on their gas bills from reducing usage. Pilot participants tended to be highly satisfied with their devices and the Pilot and reported feeling more comfortable in their homes. Most respondents also perceived their thermostat to be of excellent or very good value. In particular, Nest respondents were more likely than their EnergyHub counterparts to believe that their device provided them with excellent value.

- **Customer Equipment and Energy Consumption Characteristics:** An important aspect of recruiting customers is considering the type of equipment that new program equipment is replacing. For instance, studies suggest that replacing a manual thermostat with a smart thermostat yields higher EE impacts than replacing a programmable thermostat. The survey conducted for this study indicates that respondents typically replaced smart or programmable thermostats (70%) regardless of vendor. Notably, there were few differences in terms of demographic and household characteristics across vendors or participant type, as well as in terms of baseline energy consumption.

- **Customer Interest and Adoption:** The Pilot employs a BYOT delivery model, which uses vendor-driven marketing approaches to achieve enrollment needs. Each vendor was responsible for the recruitment of customers. Nest was the only vendor that achieved both enrollment goals. Market research indicates that smart thermostats "constitute the next generation of home automation devices that form a significant part of smart homes."[17] By the end of 2016, nearly half of all thermostats sold will be smart thermostats, according to research from Parks Associates.[18] However, vendors suggested that awareness of devices is still fairly low, as the market is, as one interviewee stated, "moving from an early adopter to mass market stage." However, vendors noted that capture is difficult, and depends on marketing the value of the device.

- **Customer Free-Ridership:** Free-ridership tended to be high for new enrollee Pilot participants. More than half (54%) of new enrollee respondents would have paid full price for the smart thermostat without the $100 incentive. This varied by vendor and was higher for Nest (0.63) and Honeywell (0.62) than EnergyHub (0.48) participants.

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[17] http://www.grandviewresearch.com/industry-analysis/smart-thermostat-market
[18] http://www.greentechmedia.com/articles/read/smart-thermostats-start-to-dominate-the-market-in-2015

6.2 Lessons Learned and Recommendations for Program Deployment

Hydro One developed the BYOT Pilot to assess whether a full-fledged program would merit the costs of deployment. Notably, for any pilot effort, considerations for scalability must take pilot results, additional context, sensitivity analyses, and other factors into account when projecting the success of future efforts. In many cases, a pilot can differ from a program in terms of how the program is designed and delivered, such as the selection of vendors that market and deploy their devices, marketing and outreach targeting and communication channels, and the customers who are eligible for the program.

Pilot scalability and viability are dependent on future program goals. The Pilot was developed to better understand the type of DR and EE benefits a smart thermostat program could provide to customers and Hydro One. Future program design and delivery should reflect the anticipated goals.

- If a future program focuses exclusively on *EE savings*, the recommended delivery approach would be to exclude all flippers (who are free-riders) and target customers with the highest potential to save with the lowest free-ridership.

Future program design and delivery should focus on maximizing the benefits and minimizing the costs associated with full roll-out through careful marketing and targeting to future program participants, revisions to participant eligibility, the offer of a tiered incentive structure, and a guarantee that vendors ensure high performance of their devices. Further, if pursuing EE savings benefits, an alternative research design (see below) should be considered to support an unbiased assessment of energy savings impacts.

Below, we describe lessons learned during the Pilot and provide recommendations, and considerations, for scaling to a full BYOT program.

Enhance Vendor Marketing Strategies

Not all vendors were able to recruit and enroll the desired number of participants for the Pilot. Notably, according to vendors, the Pilot was offered during a short time frame, and not all potential marketing channels were leveraged across each of the participating vendors.

- *Recommendation:* Co-brand with the utility to support customer engagement and recognition.

- *Recommendation:* To support increased EE impacts, employ multiple and effective marketing strategies (such as point of sale retail rebates, or direct mail targeted to lower income customers that may reduce free ridership) for a longer period of time. Marketing strategies should mitigate free ridership concerns while supporting enrollment objectives.

Market awareness for smart thermostats is building, but consumers are still in the early stages of adoption. Program participants tend to be motivated to purchase their devices to save money on their energy bill and to achieve energy savings.

- *Recommendation:* Leverage motivations identified through customer survey research to direct effective messages to future program participants. Pilot survey respondents indicated that the following features were most influential when deciding to participate in the pilot: saving money on bills, enrollment incentives, energy savings and trying a new technology.

The marketing strategies deployed have implications on EE free-ridership associated with a future program. For example, the Nest marketing strategy included hand-raiser customers (those who had requested to be on an internal Nest marketing list prior to the Pilot) to provide an incentive for the device. These customers are especially likely to be EE free-riders.

- *Recommendation:* In the future, for any energy efficiency-driven program, exclude or offer a lower incentive to customers who have already requested a device through their vendors.

Refine Customer Targeting and Eligibility Criteria

A review of existing evaluations of smart thermostat pilots indicate that customers who replace manual thermostats with smart thermostats yield higher EE impacts than those who replace programmable thermostats.

- *Recommendation:* A future program would benefit from targeted eligibility criteria to maximize EE impacts. These include customers with manual thermostats (as opposed to programmable or smart thermostats); higher baseline consumption (particularly for heating and cooling periods); and 12 months of pre-installation energy consumption data to support evaluation efforts.
- *Recommendation:* Leverage the utility's existing general population research to identify the volume of customers who meet these criteria, and assess whether the program can effectively recruit targeted customers cost-effectively.

Offer Tiered Incentive Structures

Free-ridership tended to be high for new enrollee Pilot participants with a NTG score of 0.61 overall for the Pilot. Further, more than half (54%) of new enrollee respondents would have paid full price for the smart thermostat in the absence of the $100 incentive. Importantly, flipper customers were considered full free-riders for the BYOT Pilot because they had already purchased the device prior to the Pilot. As such, the incentive to participate in the DR portion of any program should reflect participation in events, rather than device incentives.

- *Recommendation:* Depending on the goals of a future program (e.g., EE impacts, DR impacts, or both), Hydro One should consider offering varying incentive structures to recruit participants who would not have purchased the device without the incentive (e.g., minimizing free-ridership).
  - For DR impacts, recruit flipper devices only and provide lower incentives for these customers to participate in the program. Further, Hydro One could justifiably offer a lower incentive for DR participation for these customers than for a standard load control switch program because customers are more easily able to opt out of events. Where cost-effective, recruit new enrollees who can provide a high degree of load impact reduction.
  - For EE impacts, recruit new enrollees who are less likely to be free-riders. This means excluding flippers from any program (as they are considered complete free-riders) and focusing exclusively on new enrollees. In addition, if possible, provide tiered incentive structures for customers with equipment or baseline consumption practices that are more likely to provide EE savings, such as manual thermostats and higher winter and summer energy consumptions on average.
  - For both DR and EE impacts, provide a DR event participation incentive to all customers and a device incentive only to new enrollees.

- Should Hydro One continue to offer a range of eligible smart thermostats, consider varying incentive levels based on the price of these devices (e.g., more expensive devices may require higher incentive levels). Many of the Pilot participants tended to be highly educated, high-income customers who suggested that they would have purchased the device even without the incentive. Targeting customers with lower-income profiles may improve free-ridership results and energy savings.

Ensure Capture of Vendor Data and Optimize Technology Performance

Overall, the smart thermostats performed well and vendors executed DR events smoothly. However, some data that would have helped to better understand customers and support future program design was not available from the vendors. For example, we captured information regarding customer and household characteristics to inform our analysis, but some equipment and household information could suffer from recall bias, especially for flippers, who may have installed their thermostats years before the survey.

- *Recommendation:* For a future program effort, work with vendors to capture additional information about program participants when enrolling or calling events for customers to support optimal program delivery and targeting efforts. This includes:
  - Information regarding the type of thermostats replaced and whether HVAC equipment was replaced within a similar period. This will help contextualize program impacts and isolate them from other changes that may affect energy consumption. For example, this information could help support identifying whether customers who replace programmable thermostats with smart thermostats have lower energy savings than those who replace manual thermostats.
  - Provide information on customer-specific adjustments to thermostat set points during DR events, as well as overall, to support better understanding of drivers of energy efficiency and DR savings in support of future participant targeting or thermostat optimization strategies.

Smart thermostats provide unique opportunities for customers to engage with their energy consumption, as well as their devices. However, as can be seen from the impact results, a potential explanation for lower than anticipated gas EE savings results may reflect variations in the way Pilot participants engaged with their thermostats and/or variations in the operation of the thermostat (e.g., each vendor has different algorithms that it employs to achieve EE impacts) across vendors. Customer engagement with their device may contribute to higher or lower energy efficiency savings – the hypothesis is that some customers may override efficiency settings as they engage more frequently with their device. Our survey results show that Nest respondents were more likely to make adjustments to their thermostat, and with greater frequency, than Honeywell or EnergyHub respondents. One could hypothesize that frequent adjustments, particularly to pre-programmed settings, could have implications on EE savings.

- *Consideration:* Assess the relative potential for EE savings optimization across the smart thermostats. If there are differences in how smart thermostat algorithms respond to temperatures across devices, it means that some operate more efficiently. To do so, we recommend modeling runtime of HVAC units including weather by thermostat type and comparing those results to the evaluated energy efficiency models.
- *Consideration:* We recommend integrating customer self-reported engagement with thermostat set point data and other instances of customer engagement (e.g., logging into the app, setting features, etc.) to provide a robust characterization of engagement by participant and across vendors. This profile

of engagement could be applied to groupings of energy efficiency savers – e.g., high, medium and low savers, to assess correlates between engagement and energy impacts by vendor.

Revise Program Delivery Model

The Pilot used a BYOT model with a vendor-driven marketing approach, which complicated the EE impact evaluation. While the Pilot DR impact evaluation used a RCT to support the highest level of rigor, the estimation of EE impacts used a quasi-experimental design that may have produced biased estimates of energy impacts.

- *Consideration:* Deliver a program that supports the least biased estimation of EE impacts through offering the program via a randomized encouragement design (RED).[19] A RED is an experimental design that allows program implementers to offer the program with an opt-in design without denying or delaying enrollment to eligible customers while also yielding an unbiased estimate of energy impacts. Notably, this design requires a large number of participants to produce savings estimates, so it may not be feasible if there is low market adoption of the program. An added benefit to this design is that it categorizes customers into three profiles: those who will never join the program (never-takers), those that will always join the program (always-takers), and those that will join only if they are encouraged (compliers). These customers can be targeted to support minimizing free-ridership in future program years.

6.3 Recommendations for Future Research

The BYOT evaluation effort yielded rich information regarding Pilot performance and opportunities to enhance future program roll-out. However, there are additional areas of research that would help refine future program design and delivery.

Evaluation results suggest that additional research focused on optimizing incentive structures to limit free-ridership and identifying high-value target customers could support the delivery of a cost-effective program. Below we offer future research recommendations to:

- *Optimize Incentive Structures:* The Pilot evaluation fielded a series of willingness-to-pay questions to program participants through customer surveys to gain a sense for optimal incentive levels for a future program. However, this approach was limited because we asked customers how much they would pay for a device that they had already purchased. Hydro One could conduct additional research with the general population of customers regarding their willingness to pay for smart thermostats. By gathering data from a broader audience, this additional discrete choice study could support the development of the program incentive structure in a way that could also minimize future free-ridership.[20]

- *Identify High-Value Target Customers:* The evaluation results indicate that there are customer characteristics associated increased EE and DR impacts.

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[19] For more information on random encouragement design, refer to SEE Action Networks, "Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations Customer Information and Behavior Working Group Evaluation, Measurement, and Verification Working Group," May 2012. http://eetd.lbl.gov/sites/all/files/publications/ behavior-based-emv.pdf.

[20] A discrete choice method relies on customer-stated preferences and uses a random experimental design to measure the trade-offs between price and non-price product attributes and, as a result, estimate price elasticities. From these price elasticities, we can calculate free-ridership and ultimately net-to-gross.

- *Model Energy Efficiency Impacts by Customer Groups and Seasons:* This evaluation provides overall, seasonal, vendor, and participant type impact results. There may also be other customer groups that correlate with high savings. Additional models could inform future program roll-out and specifically customer targeting of potentially high-impact groups. We suggest estimating EE impacts by groupings (e.g., quintiles) of baseline energy consumption to better understand the dependence of prior energy consumption on energy savings potential. Hydro One may be interested in an analysis to incorporate runtime data with hourly AMI data to estimate heating and cooling savings, which is important because thermostat programs typically provide the greatest impacts during the heating and cooling seasons and at peak times during those seasons.

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Appendix B

Transition Plan

January 2018

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Introduction:

Integrated Resource Planning ("IRP") refers to a multi-faceted planning process that includes the identification, preparation, and evaluation of all realistic supply side and demand side options in order to determine the least cost for customers and lowest risk approach to addressing transmission and distribution infrastructure ("infrastructure") requirements. This could include a review of a variety of different low carbon options such as energy efficiency to defer existing regional and local infrastructure; the impact of net zero ready subdivisions; distributed energy resources (i.e. renewable natural gas); community energy planning; and the least cost lowest carbon solutions. IRP could also focus on the interplay of these various energy options and the subsequent impact on infrastructure to meet system demand.

The Enbridge / Union Gas IRP Study upon which this Transition Plan is based, considers a component of Integrated Resource Planning, specifically, if and how the implementation of Demand Side Management ("DSM") may be used to defer or eliminate the need for infrastructure development. ICF, a well-known energy conservation consulting firm was engaged by the utilities to undertake the study. The conclusions from ICF's work are summarized in Table 1 below and explained in more detail in the Executive Summary, these findings have been helpful to the utilities in developing this Transition Plan. The findings also point to the necessity for more insight, including the completion of the currently underway in-field case studies in order to come to any definitive conclusion about traditional DSM's role in supply planning. Over time, IRP may evolve to consider other scenarios that provide cost effective, safe, reliable and low carbon impact solutions.

Regardless, the utilities paramount obligation is to deliver safe and reliable energy to our customers. As such, a measured and fact-based approach is critical to any planning considerations.

Table: 1

	IRP Study Conclusions:
1	Based on ICF's initial assessment of the potential to reduce peak hour demand using DSM, it appears possible that some infrastructure investments may be reduced through the use of targeted DSM.
2	Changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce infrastructure investments.
3	Changes in utility planning processes would be necessary to facilitate the use of DSM to reduce infrastructure investment.
4	Additional research is necessary before the Gas Utilities would be able to confirm DSM could reduce infrastructure investments.

This document serves as the utilities' Transition Plan and outlines the roadmap for IRP development over the next few years. As with any roadmap it is intended to be a starting point for clarity around activity and outcomes, but is anticipated to evolve. The utilities are undertaking case studies to test in field the conclusions of the IRP study and inform the transition to IRP. In addition, to the activities outlined in this Transition Plan, the utilities continue to analyse and plan for traditional infrastructure requirements, low carbon solution development including behind-the-meter options, and energy efficiency results.

Background – The Regulatory History of IRP and DSM in Ontario:

IRP has been considered in the regulatory environment in Ontario since the early 1990s. In 1991, the Ontario Energy Board ("the Board") issued a Discussion Paper prior to commencing a generic proceeding into Least Cost Planning (later renamed Integrated Resource Planning).

Although the supply and demand side options considered within IRP can be quite broad, in recent years, much of the discussion has focused on the impacts of Demand Side Management (DSM) and energy efficiency. Between 1995 and the present, the gas utilities in Ontario have engaged in DSM activities, generating significant natural gas savings and have provided passive infrastructure savings by reducing demand in a broad based system wide context.

Specifically, attention was given to energy efficiency's potential role, in the context of geo-targeted infrastructure planning during the Enbridge GTA Reinforcement Project, EB-2012-0451.

The 2015-2020 DSM Multi-year Plan Decision directed that:

> "Enbridge and Union to work jointly on the preparation of a proposed Transition Plan that outlines how to include DSM as part of future infrastructure planning activities. The utilities are to follow the outline prepared by Enbridge, and should consider the enhancements suggested by the intervenors and expert witnesses. The Transition Plan should be filed as part of the mid-term review""

Further, in the OEB letter dated June 20, 2017, with respect to the DSM mid-term review, the Board directs the utilities in the second requirement due January 15, 2018, and as outlined on page 4 "to submit a transition plan to incorporate DSM into infrastructure planning activities."

Transition Plan Purpose:

This Transition Plan serves to meet the Board's filing requirement, and is a companion document to the IRP Study Executive Summary Report. The Transition Plan lays the pathway for considering IRP over the coming several years focusing in the shorter term on the specific role of energy efficiency in supply planning and in the longer term may serve as a foundation for a broader approach to IRP. The utilities believe this roadmap will aid in the coordination between distribution planning processes and analysis, and low carbon alternatives including energy efficiency.

Transition Plan Objectives:

As noted above, the Board directed the utilities to file an IRP Transition Plan as part of the DSM Mid-Term Review that "outlines how to include DSM as part of future infrastructure planning activities"[1].

The Transition Plan's objectives are to:

- Identify the process phases that the utilities will move through to ensure implementation of a formalized IRP process including DSM as per the Board's direction,
- Indicate how the utilities will internally organize to ensure that DSM is a consideration in infrastructure planning,
- Indicate an internal governance structure to ensure the implementation of an IRP planning process.

IRP Study Scope /Outline:

The Enbridge / UG IRP Study provides insight on what IRP may include for natural gas utilities, how it may function, and some analysis on possible outcomes. The utilities recognize that Integrated Resource Planning will require more formalized considerations to optimize safe, reliable, cost effective and low carbon energy solutions for our customers.

The IRP Study assesses if and how energy efficiency can be leveraged by Enbridge and Union Gas to potentially avoid, defer or reduce future geo targeted gas infrastructure investment. In the future, treating IRP with a broader brush by introducing not just a binary discussion around demand and supply planning for natural gas, but also a diversified range of energy solutions and scenarios that may include energy efficiency, demand response, renewable energy or distributed energy systems among others, may be necessary to contribute towards carbon reduction targets. Broader IRP planning may constitute a next phase to this transition and analysis work.

The Study as scoped focused on three areas of overlap (intersections) between DSM planning and infrastructure planning:

Intersection 1: Broad based DSM and Distribution Infrastructure Planning
Intersection 2: Subdivision and New Community Planning
Intersection 3: Targeted DSM and Reinforcement Projects

Planning Processes:

The utilities DSM and Infrastructure planning processes are currently informally integrated and to move to an IRP process, these two processes would require a more systematic, formalized and comprehensive integration.

DSM Planning Process: The utilities DSM planning processes and programs reflect the Board's DSM Framework, and related Decisions, as well as continuous improvement driven by the utilities learnings over time. The Board's DSM Framework measures and incents the reduction of annual gas consumption throughout Ontario, with the ultimate goal being to ensure that savings are verified and achieved efficiently while customers receive "the greatest and most meaningful opportunities to lower their bill by reducing consumption."[2] Put another way, DSM focuses on broad based annual savings across the franchise areas that drive maximum bill reduction, versus a jurisdictionally bound, peak hour load reduction to influence supply planning.

Currently, the natural gas DSM plans inherently account for potential savings in system wide infrastructure created by DSM savings through avoided distribution costs. Avoided costs include costs such as capital for distribution infrastructure and operating costs, avoided demand-side costs such as operation costs, and storage costs, transportation tolls and demand charges. As part of the IRP Study there are considerations given to determining the avoided reinforcement distribution costs on a geo targeted basis, as this helps to inform the potential of DSM to defer infrastructure, also sometimes referred to as active (geo targeted) deferral.

***Infrastructure Planning*:** Infrastructure planning is based on a long term load forecast intended to identify potential system constraints leading to incremental infrastructure requirements and to develop these plans prior to the need for new infrastructure. The primary goal of infrastructure planning is to ensure that the utilities' infrastructure is sufficiently robust to provide reliable and safe natural gas service that meets the design condition peak hour requirement forecast, consistent with reasonable costs. The utilities are also bound by certain design parameters with respect to its natural gas distribution and transmission systems, these design parameters ensure the safe and reliable delivery of natural gas to its customers.

The impact of broad based DSM programs on infrastructure investment is inherently captured in the infrastructure planning process. Historical gas throughput is used as a base to predict future consumption and is updated each year. These historical forecasts include changes in gas usage resulting from implementation of historical DSM measures, as well as other natural conservation factors such as improved building codes, and higher energy efficiency standards for natural gas equipment. The infrastructure plans do not explicitly factor in future projections of DSM program effects on peak day or peak hour demand. Network analysis and infrastructure planning adjusts its forecast in gas demand on a regular basis to ensure trends are reflected in the most recent results. Reinforcements are only executed when needed and the scope is adjusted as required. To put this into context the reinforcement expenditures for both utilities, on average over ten years, is approximately 13% - 15% of the total forecasted capital expenditures.

Previous and Current Planning Processes:

DSM and infrastructure planning processes have occurred somewhat independently in the past for both utilities. These processes have worked well and have provided for both the accurate management of DSM budgets and annual / cumulative savings targets on one hand, and the infrastructure planning process that has allowed for a robust, safe and reliable distribution system on the other. Both of these planning processes support the Ontario Energy Board's Consumer Charter which amongst other

[2] Report of the Ontario Energy Board 2015-2020 Natural Gas DSM Framework Page 1

Consumers rights, indicates that Consumers have the rights to a safe and reliable service, as well as the right to access available energy conservation programs.[3]

Moving forward, IRP affords the utilities the opportunity where appropriate to coordinate and integrate the processes between demand and supply in infrastructure planning. A more systematic IRP process may require new and evolved processes as well as incremental resourcing or technology infrastructure such as installation of advanced metering infrastructure to provide automated metering. The utilities are committed to a transition to IRP and see the opportunities from a due diligence and continuous improvement process model, recognizing that benefits may result from both the review and integration of the various planning processes. As more is known about how energy efficiency, demand response and carbon policy impact the natural gas distribution system, outcomes may not be as straightforward as anticipated. For example, if there is a GHG reduction program that decreases annual load but at the same time increases peak hour, infrastructure requirements may need to adjust to ensure the safe and reliable delivery of natural gas to customers. In particular, the IRP Executive Summary outlines that adaptive thermostats decrease annual electric and gas load, but actually increases winter peaking load for the natural gas utilities. This means that while carbon reduction goals are being met, incremental infrastructure may be needed to meet the higher winter peaking requirements

Future Integrated Planning Processes:

Continued analysis and monitoring of DSM programs and higher energy efficiency equipment, as well as any subsequent impacts of these initiatives on peak period demand should be conducted and factored into infrastructure requirement planning and forecasting processes.

The current in-field case studies being completed in the market by both utilities will further inform the IRP Study findings by creating more understanding of the impacts of broad-based DSM programs and technologies on peak hour demand. Using this information, the utilities will be able to make informed decisions, based on cost benefit analysis using the appropriate avoided distribution costs to more accurately identify those infrastructure projects that have a potential to be deferred by the implementation of targeted DSM programs. Where possible, alternative lower carbon energy solutions may be considered. All of this would need to be done with consideration to customers' energy bill impacts.

The utilities recognize that the certainties required for infrastructure planning on actual peak hour demand resulting from higher efficient equipment will need to have a high degree of accuracy. The utilities will consider further research including load research and technology assessment and analysis to ensure that there is an ongoing continuous improvement cycle of the information and assumptions used in the IRP process.

In order to stay abreast of industry best practices, the utilities will monitor on a continuing basis, industry best practices and the enhancements to Natural Gas IRP in North America as well as participate in and / or establish industry and utility groups that are looking at Natural Gas IRP, and broader energy

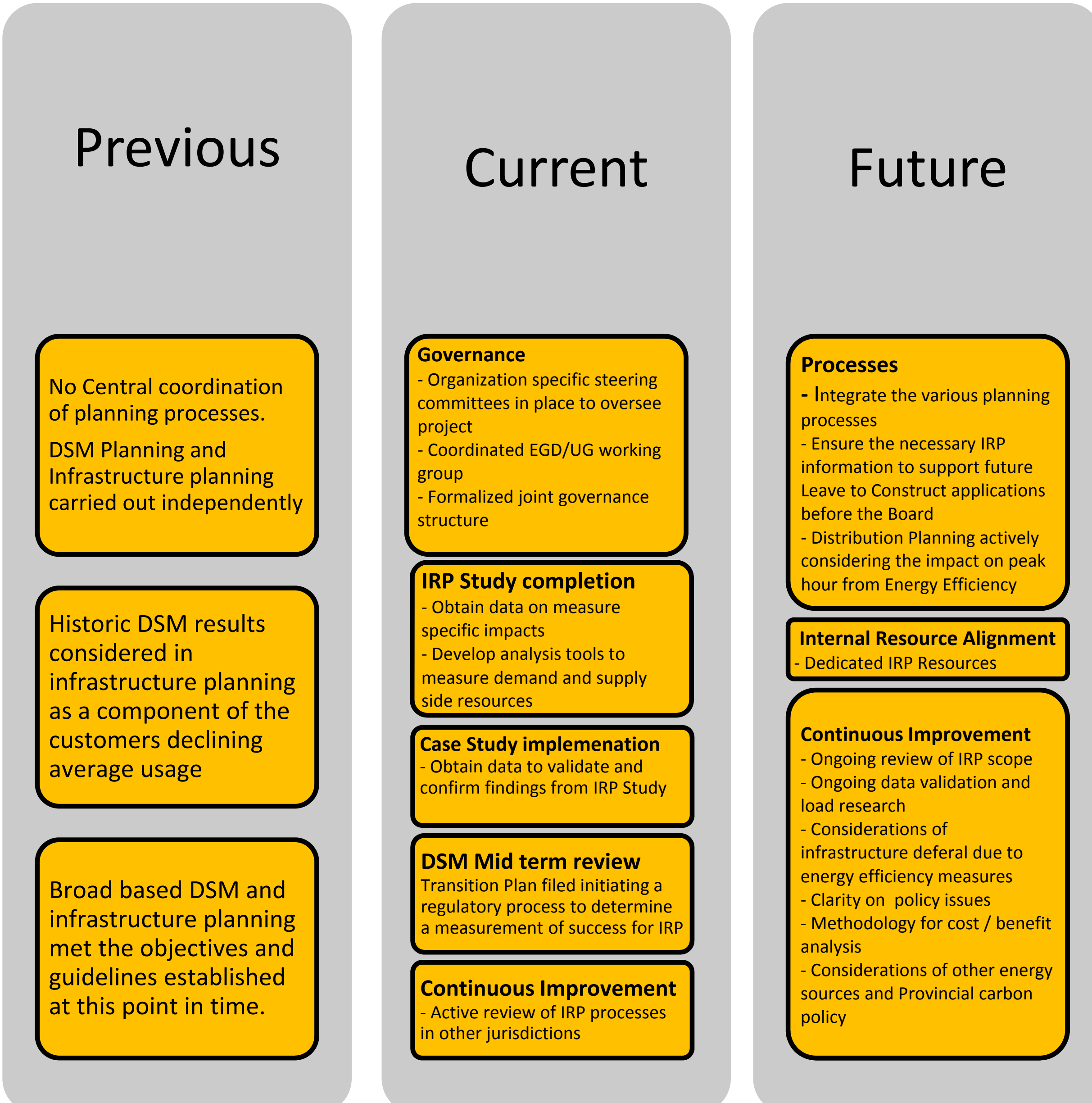
[3] https://www.oeb.ca/consumer-protection/how-we-protect-consumers/consumer-charter

pathway discussions. Moving forward into an IRP model affords the opportunity to review, coordinate and integrate processes between demand and supply in infrastructure planning.

Underscoring all of these activities will be the evolution and implementation of the Province's climate change and related carbon policies and spending, recognizing that the Government's priority of reducing GHG emissions may necessitate consideration of IRP priorities and processes. The dynamics between energy efficiency's impact on peak demand and the distribution system, versus the annual savings and reduced GHG emissions would need to be fully understood. Put another way, there will need to be consideration given to whether there is alignment moving forward around carbon planning and integrated resource planning, and if there is not alignment, which will take priority?

Elements of the planning processes are identified in Figure 1, highlighting the progression of planning from its previous process to the utilities current IRP activities and future considerations.

Figure 1:



Integrated Resource Planning Transition Roadmap:

The Transition Roadmap initially spans over the next few years to accommodate the desktop review/paper portion of the IRP Study, the anticipated regulatory process and the more time intensive in-field case studies.

Phase 1 – 2017:

- IRP Study ongoing,
- Joint utility Working Group created pre-2017, remains in place to support implementation of the IRP Study completion and ensure timelines and deliverables completed,

- Joint utility Steering Committee assembled to provide governance and oversee implementation of IRP Study,
- IRP in-field case studies designed and initiated,
- AMR metering installed in case study areas in time to record winter customer usage patterns.

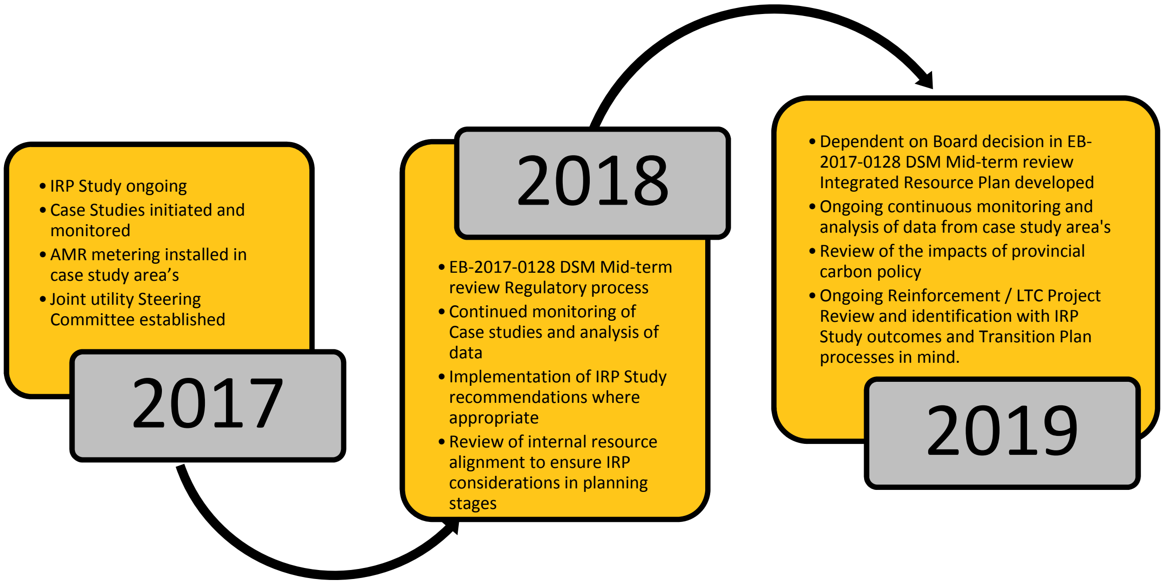
Phase 2 – 2018:

- IRP Study Executive Summary and Transition Plan filed during EB-2017-0128 DSM Mid-term review, joint utility Working Group to support and participate in all regulatory processes related to the Transition Plan and IRP Study,
- Continued monitoring and analysis of in-field case study findings, reviewing both DSM participants and non-participants,
- Identification of resourcing and infrastructure necessary to implement any IRP Study recommendations,
- Implementation of IRP Study recommendations that do not require additional resources or infrastructure where appropriate,
- Monitoring of Provincial carbon policies and funded energy efficiency programs, CDM activity, to identify if any, the impacts on infrastructure planning and design.

PHASE 3 - 2019:

- Dependent on the direction received from the Board during the EB-2017-0128 DSM Mid-term review, begin process of developing an Integrated Resource Plan which may include identifying necessary resources, data or enabling technology infrastructure requirements,
- Continued consideration of scope of IRP,
- Continued monitoring and analysis of data gathered from AMR metering from in-field case studies where DSM measures have been and are still being installed,
- Ongoing Reinforcement / LTC Project Review and identification with IRP Study outcomes and Transition Plan processes in mind,
- Consideration of the impacts of Provincial carbon policies, programs and regulations.
- Continued monitoring (and possible completion) of in-field IRP case studies.

Figure 2:



Governance Structure:

A key component of the integration of IRP at the utilities is ensuring that the senior management of both utilities is engaged, informed and aware of the IRP roadmap and phases to implementation. In moving forward with the IRP Study implementation, and to ensure continued collaboration a joint Utility IRP Steering Committee made up of Vice Presidents from both organizations will provide oversight, policy direction, and advise on an appropriate organizational structure in keeping with greater corporate goals.

The primary function of the joint IRP Steering Committee will be to oversee completion of the IRP Study in the short term, and provide long-term stability for IRP development at the utilities.

The IRP Steering Committee will be tasked with approving major IRP related development elements such as:

- Deliverables as identified in the IRP Study,
- Ensure the objectives meet the OEB requirements and customer/stakeholder interests,
- Budget, ensuring that effort, expenditures and changes are appropriate to ensure IRP integration,
- Risk management strategies, ensuring that strategies to address potential issues with the IRP processes have been identified, estimated and approved, and that the issues are regularly re-assessed,
- Understand how IRP aligns with corporate objectives, and,
- Define what success looks like and ensure measures are implemented which track progress.

Summary and Next Steps:

This Transition Plan outlines how the utilities will move forward with development and implementation of IRP including consideration for its ongoing governance. A summary of results of the IRP Study are included in the Executive Summary, along with information on next steps for future consideration of the utilities.

Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment

Executive Summary

January 2018

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Executive Summary

1. Introduction, Scope and General Conclusions

1.1 Introduction

Integrated Resource Planning ("IRP"), has been considered in the regulatory environment in Ontario since the early 1990s. Between 1995 and the present, the gas utilities in Ontario have engaged in Demand Side Management ("DSM") activities which have generated significant natural gas savings across all rate classes as well as likely provided passive infrastructure investment savings by reducing demand in a broad based context.

Recently, the role of geo-targeted DSM programs in the infrastructure planning process was raised during the EB-2012-0451 proceeding as part of the review of the Enbridge GTA Reinforcement Project. The Board followed up on this question in the 2015-2020 DSM Framework issued by the Board on December 22, 2014. In this decision, the Board directed the

> "gas utilities to each conduct a study, completed as soon as possible and no later than in time to inform the mid-term review of the (2015-2020) DSM Framework".[1]

Further, the Board stated that it,

> "expects the gas utilities to consider the role of DSM in reducing and/or or deferring future infrastructure investments far enough in advance of the infrastructure replacement or upgrade so that DSM can reasonably be considered as a possible alternative".[1]

Enbridge included a proposed study scope in EB-2015-0049. The study scope was designed to evaluate the potential to use DSM to avoid or defer (reduce) infrastructure costs through implementation of broad based or geo-targeted DSM programs to meet the forecasted hourly peak energy demand, consistent with the primary goals and principles of facilities planning, to provide reliable natural gas service with reasonable costs.

The study scope was reviewed by intervenors and ultimately approved by the Board in the DSM Multi-Year decision. Enbridge Gas Distribution and Union Gas Limited ("the Gas Utilities") jointly engaged ICF to conduct this study.

This executive summary provides an overview of the primary considerations and conclusions reached by ICF during the course of the study.

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[1] OEB, Report of the Board: Demand Side Management Framework for Natural Gas Distributors (2015-2020), pg. 36, Dec. 22, 2014, available at: https://www.oeb.ca/sites/default/files/uploads/Report_Demand_Side_Management_Framework_20141222.pdf

1.2 Overview of Study Scope

Given the ultimate goal of identifying a process to ensure that DSM is considered as an option to avoid, defer or reduce ("reduce") infrastructure investment costs, the study attempted to identify the barriers to using DSM as an option, and to propose processes to address and overcome these barriers.

The scope of the study included the following items:

1. ***Review of Industry Experience***: ICF conducted a literature review in which it evaluated how other leading utilities address issues related to broad-based DSM and distribution infrastructure planning and issues related to the impact of DSM programs on sub-division and new community planning. ICF also reached out to and interviewed leading North American utilities identified as having experience working on integrated resource plans
2. ***Assessment of DSM Impacts on Peak Hour and Peak Period Requirements***: ICF leveraged the results of the 2016 OEB Conservation Potential Study (CPS) and developed load profiles and hours use factors to estimate the winter peak period demand breakdown and the achievable winter hourly peak demand reduction from DSM for the Gas Utilities. ICF also developed DSM supply curves to assess the costs of DSM implementation against the demand saving impacts.
3. ***Application of DSM Supply Curves to Facility Investments***: ICF leveraged the results of the DSM impacts analysis to understand the potential of DSM programs to defer infrastructure investments (i.e. delay the need for additional capacity for new construction and reinforcements projects). As part of this step in the process, ICF worked with utility staff to identify appropriate hypothetical case studies based on specific examples of utility infrastructure investments. Information from these case studies that fed into the analysis included project costs, current and forecasted capacity requirements, and the distribution of energy consumption by facility type. The DSM supply curves developed in step 2 were used to compare the costs of peak demand reduction through the implementation of DSM against infrastructure project costs.
4. ***External Review and Stakeholder Engagements***: Throughout the IRP study, ICF and the Gas Utilities consulted with a Study Advisory Group (SAG) in order to gain insights on IRP processes for similar utilities and to discuss the study approach and findings. The SAG was made up of members from other North American gas utilities, the Independent Electricity System Operator (IESO), the academic community, as well as an observer from the Ontario Energy Board Staff. The study has benefited from the hands-on experience of staff in other organizations that have undertaken system-wide Resource Planning. This external review has brought a broad perspective to the study and helped to ensure the quality of the study across the several specialized fields involved.
5. ***Transition Plan***: The OEB directed Enbridge and Union to work jointly on the preparation of a proposed transition plan that outlines how to include DSM as part of future infrastructure planning activities within the Utility Planning Process. This ICF study provided critical insights used by the Gas Utilities during the development of the Utilities' Transition Plan. The Transition Plan will be filed with the OEB by the Gas Utilities as a companion document to this report.

1.3 Study Highlights

ICF's review of existing DSM programs at North American gas utilities in other jurisdictions found that little to no activity has been undertaken to directly reduce transmission and distribution costs using targeted DSM and Demand Response (DR). In addition, ICF found that the measured data on hourly natural gas consumption necessary to determine the potential impacts of DSM on new facilities requirements is generally unavailable.

ICF also assessed activity in the electric power industry. However, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts lead ICF to the conclusion that geo-targeted DSM programs are likely to be more cost-effective for the electric industry than they are for the natural gas industry, and that the electric industry experience provides only relatively limited value as an example for the gas industry.

Due to the lack of industry experience, and the lack of measured data on DSM peak period load impacts, ICF conducted most of the research into the potential for DSM to impact infrastructure requirements by extrapolating existing data on DSM program impacts from annual data to peak hourly period data based on building modeling, and other theoretical analysis. While ICF views the analysis as robust, there remains significant uncertainty, particularly on the cost and reliability of using DSM to reduce infrastructure investment. Hence, our conclusions should be treated as preliminary until additional research is completed.

1.3.1 Highlights

A more detailed discussion of ICF's general conclusions from this study are reviewed in Section eight of this executive summary. Highlights from the study are summarized below.

1. ***Based on ICF's initial assessment of the potential to reduce peak hour demand using DSM, it appears possible that some infrastructure investments may be reduced through the use of targeted DSM*.**
   a. While there is little to no measured data on actual peak hour impacts of DSM programs, ICF's analysis indicates that many, but not all, DSM measures should be expected to have measurable impacts on peak hour natural gas demand.[2]
   b. ICF's analysis suggests that geo-targeted DSM programs would have the potential to offset demand growth by up to about 1.24 percent per year, before consideration of DSM program and measure costs.
   c. Opportunities to reduce facilities investments through the use of geo-targeted DSM are likely to be limited due to the cost of geo- targeted DSM programs relative to the cost of the infrastructure, as well as the maximum penetration rate of DSM programs, which appears likely to be lower than the rate of growth in areas where a significant share of new infrastructure projects are indicated.

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[2] The clearest example is the inclusion of adaptive thermostats in DSM programs, which account for a significant amount of potential annual energy savings available through DSM programs, but appear likely to increase peak period infrastructure requirements.

2. ***ICF's review indicates that changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce infrastructure investments.*** These include:

    a. Cost recovery guidelines for overlapping DSM and facilities planning and implementation costs, and criteria for addressing DSM impact risks.

    b. Approval to invest in, and recover the costs of the Advanced Metering Infrastructure (AMI) necessary to collect hourly data on the impacts of DSM programs and measures.

    c. Changes in the approval process for DSM programs to be consistent with the longer time frame associated with facilities planning.

    d. Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facilities investments.

    e. Guidance on cross subsidization and customer discriminations inherent in geo-targeted DSM programs that do not provide similar opportunities to all customers.

    f. 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 improve energy efficiency.

    g. Guidance on how to treat uncertainty associated with energy efficiency programs outside the control of the Utilities that impact peak period demand.

3. ***ICF's review indicates that changes in utility planning processes would be necessary to facilitate the use of DSM to reduce infrastructure investment.***

    a. Facilities planning is based on an avoidance of risk due to the potential consequences associated with the lack of necessary infrastructure, while DSM program design does not generally need to address similar concerns. The differences in risk profiles create significant challenges in incorporating DSM programs into the facilities planning process.

    b. Geo-targeted DSM programs will need to be implemented during the early stages of the facilities planning cycle in order to maximize the impact of the geo-targeted DSM programs and to facilitate risk management if the DSM programs do not meet objectives.

    c. Other differences between the DSM and facilities planning process within the utilities that must be reconciled include differences in asset lifetimes, cost-effectiveness criteria, and program assessment and planning timeframes.

1.3.2 Recommendations for Additional Analysis

Overall, there is currently a fundamental disconnect between the limited risk acceptable to the Utilities in the facilities planning process and the lack of information on the ability of DSM to reliably reduce peak period demand that will need to be addressed before the Utilities would be able to rely on DSM to reduce infrastructure investment:

- The lack of measured data on the actual impacts of DSM measures on peak period demand increases the risk (hence the cost) of using DSM to reduce infrastructure investments.

- The lack of reliable program implementation cost data for geo-targeted DSM programs makes accurate cost comparisons between facilities and DSM unavailable.
- The maximum market penetration rate for geo-targeted DSM programs limits the number of infrastructure projects where geo-targeted DSM programs should be considered as an alternative to infrastructure projects to low growth market areas.

As a result, additional research and additional hourly data by way of additional metered hourly reads (i.e. automated meter reading or infrastructure installation (AMI), as well as pilot studies to determine the cost effectiveness and implementation potential of DSM programs are necessary before the Gas Utilities would be able to rely on DSM to reduce new infrastructure investments as part of the standard facilities planning process.

2. Review of Industry Experience

ICF conducted a literature and best practices review process in which it evaluated how other leading North American utilities address issues related to DSM and facilities planning, and issues related to the impact of DSM programs on sub-division and new community planning. The following subsections discuss other gas utility experiences using DSM to defer infrastructure investments and the differences found between natural gas and electric utilities' planning processes.

2.1 Utility Experience Using DSM to Defer Infrastructure Investments

As part of the review of the potential for DSM to reduce the need for infrastructure investment, ICF conducted a literature and best practices review across many North American jurisdictions to assess the state of the industry. The review focused on experience using DSM and demand response (DR) programs to reduce the need for infrastructure investment. ICF also included a review of the electric utility experience utilizing energy efficiency[3] and DR in the facilities planning process.

Based on a review of the state of the industry, there is no relevant precedent for, or evidence of natural gas utilities consideration of the impact of broad based DSM, geo-targeted DSM or dedicated DR programs impact on facilities planning. Further, while electric utilities have used DSM and DR programs to reduce the need for new generating capacity and transmission capacity for many years, there is only relatively limited experience deferring distribution system infrastructure.

ICF's review of existing energy efficiency programs at other North American gas utilities found that several other natural gas utilities have started looking into the potential impact of DSM programs on system infrastructure requirements. However, these efforts remain in the very early stages. As such, there has been much less progress on the gas side as compared with the electric power industry. Furthermore, ICF did not identify a natural gas utility in any other jurisdiction that is currently using geo-targeted DSM programs to actively avoid investing in infrastructure in specific areas. In fact, of the utilities ICF spoke to, only NW Natural Gas is planning a geo-targeted DSM program, which they are planning to implement through a pilot study.

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

Gas utilities in other jurisdictions expressed concerns about the reliability of the DSM impacts as an infrastructure investment alternative due to the lack of information, and metered data on the

[3] 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.

impacts of DSM on peak hourly demand. This is compounded by the fact that peak savings for DSM programs have not previously been tracked, although some jurisdictions are beginning to address this. For instance, Energy Trust of Oregon is tracking peak hour savings from DSM on behalf of NW Natural and Questar Gas was asked to consider the peak hour impacts of DSM measures such as tankless water heaters. Questar Gas is developing a framework to consider positive and negative peak impacts due to DSM.

ICF's review of gas industry DSM plans indicated that the estimated costs of peak day gas supply are commonly included in the avoided cost estimates used to assess the value of DSM programs. DSM is expected to reduce peak day requirements, leading to reduced need for peak day gas supply resources. Furthermore, avoided costs used to value DSM programs generally include estimates for infrastructure investment costs. These adders to the avoided costs are specific to the region in which the natural gas utility conducts business. Although they are appropriate for passive system-wide deferral from non-targeted DSM, they are generally small relative to the total avoided cost. ICF's review also found that, while the value of infrastructure investment is typically considered in the cost-effectiveness tests of DSM programs, the impact is not based on the assessment of individual infrastructure projects.

Planning staff at the utilities with whom ICF spoke expressed concerns related to leveraging DSM to defer infrastructure investments. Most of the concerns were related to the following items:

- **Reliability:** The reliability of peak hour reductions due to DSM investments
- **Lack of metered data:** Most utilities are able to identify peak hourly data only at a system gate station level and further granularity is limited. Advanced metering would be required in order to substantiate peak hour reductions from geo-targeted IRP. Questar and NWNG noted that they are considering additional metering as part of their work in the area.
- **Changing lead times for projects:** Planning staff from the other utilities indicated that a minimum lead time of 5 years is required to incorporate 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.
- **Principle of universality:** This concern was related to not offering the same programs across the entire service territory and the correct funding mechanism to use in this scenario. The other gas utilities noted the concern about the possibility for unequal treatment in different income classes, as the largest peak hour savings will accrue to larger homes and it may not be economic to provide the same benefits to lower income residences.

2.2 Differences between Electric and Natural Gas Utilities

Electric utilities have been using Demand Side Management and Demand Response (referred to in Ontario by electric utilities as Conservation & Demand Management or "CDM") programs to reduce the need for new generating capacity and transmission capacity for many years. However, the electric industry has relatively limited experience with DSM to defer distribution system infrastructure. Like natural gas DSM, most electric utility DSM programs are focused on reducing annual consumption. Where the electric utilities use DSM to offset infrastructure investment, the focus is generally on power generation capacity, or incremental transmission capacity into the company's service territory, rather than the impact on electricity distribution infrastructure. While interest in using DSM or DR to impact electricity distribution infrastructure has been increasing, so far, the information on the effectiveness of the programs has been limited.

Some concepts used for electric transmission and distribution ("T&D") facilities deferral in the IRP process can be applied to natural gas utilities. However there are some important differences between electric and gas infrastructure planning processes that need to be accounted for when trying to draw parallels between the electric industry approach to IRP and gas utilities approach. These differences include:

- **Facilities Planning Requirements:** Electricity facilities are designed to meet instantaneous peak requirements, while gas facilities are designed to meet hourly (distribution infrastructure) and hourly and daily (transmission infrastructure), and daily (gas supply) requirements.[4] These differences in planning time of day tend to increase the value of reductions in peak demand for the electric industry relative to the gas industry, which makes targeted DSM and DR programs more valuable for the electric industry than for the natural gas industry.
- **Cost Structure:** Gas facilities are typically less expensive than electric facilities per equivalent amount of energy delivered (GJ of delivered energy) for a given level of peak energy demand (peak GJ of delivered energy). As a result, utility facility costs typically make up a lower percentage of the typical customer gas bill than for their electric bill. This ultimately leads to the savings associated with a reduction in gas utility infrastructure tending to be lower than the savings available to the electric industry.
- **System Outage Risk:** Electric systems are designed with an acceptable level of system outage risk, while gas systems are designed with a higher degree of reliability. The reliability standard required for the natural gas system is discussed in more detail in the review of the facility planning process section. The higher degree of reliability required by the gas industry, with minimal risk tolerance for outages and increased costs to restart systems should outages occur, increases the costs associated with monitoring and evaluating the impacts of Geo-Targeted DSM programs targeted at avoiding or deferring infrastructure investments, and increases the risks of non-performance

[4] The peak demand period for facilities planning used in our analysis is the peak hour, which typically occurs during the morning period. For planning purposes, the peak period demand is projected based on extreme weather conditions, which typically occur on the coldest anticipated winter day, or design day. The duration of the peak period considered in the planning process depends on the type of infrastructure being evaluated. For individual service connections, the peak period used to size the service connection should be sufficient to meet the maximum customer demand. For certain distribution infrastructure projects serving a limited number of customers, the peak period used for facilities planning may need to be as short as 15 to 30 minutes, while larger transmission assets may be planned based on a longer time frame, potential a 24 hour design day.

associated with the DSM programs, and places utmost importance on ensuring savings can be realized and capacity requirements met without reinforcement.

- **Resource Planning**: Electric utilities must either acquire power and capacity from the market or produce their own. An electric utility IRP contains a review and assessment of the trade-offs between various generation and electricity purchase options. Gas utilities, in contrast, only acquire resources from the market. A natural gas IRP's purpose is to assess energy delivery infrastructure requirements needed to deliver gas to end-use customers.
- **Peak Hour Data Availability**: The need to measure peak hour electricity demand has resulted in the availability of electric "smart" meters that record data on a substantially more granular flow level than current natural gas meters. As a result, detailed data on peak hour demand at the individual customer level is available for the electric industry, and subsequently allows for assurances through data that savings will be realized. Most gas utilities customer meters are read every other month.

The differences between the electric system and the natural gas system reduce the cost-effectiveness of DSM as an alternative to new infrastructure for natural gas utilities relative to electric utilities. The electric industry can achieve greater infrastructure cost savings from similar DSM and DR measures, due to the higher cost structure of the industry. The difference in risk tolerance between the industries, for capacity shortage, also increases the attractiveness of DSM and DR for infrastructure deferral and avoidance in the electric industry relative to the natural gas industry.

In addition, the use of DSM in the electric industry to reduce capacity requirements, and the ability to accurately measure peak demand has resulted in a better understanding of the impact of DSM on peak requirements in the electric industry than in the natural gas industry. This difference reduces the risk to the electric industry associated with the reliance on DSM to displace electricity infrastructure relative to the risk to the gas industry of relying on DSM to reduce the need for natural gas infrastructure. 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.

As a result, geo-targeted DSM programs are likely to be more cost-effective for the electric industry than they are for the natural gas industry.

3. Overview of Natural Gas Facility Planning

The following exhibit provides an overview of the natural gas facility planning process. Key items are discussed in more detail in the following sections.

Exhibit 1: Overview of the Facilities Planning Process

Facility Investment Drivers
- Maintain system integrity - meet safety and operational standards
- Serve growth on a peak hour and peak day
- Facility investments are designed to meet one or both of these requirements

Growth Drivers - Meeting Peak Day and Hour on Transmission and Distibution Systems
- New customer attachments
- Increase in existing customers demand
- Changes in customer usage patterns
- Serving new communities and subdivisions

Utilities Use Multi Year Growth Forecasts
- Estimated peak hour consumption/demand for distriution systems
- Estimated DSM effects on consumption included based on historical usage
- Estimated peak hour and day demand for transmission systems
- Hourly loadshape profiles which varies the demand over the day
- Location of Growth

3.1 Facilities Planning Principles

Facility investment plans are based on a long term growth forecast intended to identify potential incremental facility requirements and to develop these plans prior to the need for new facilities. ***The primarily goal of facilities planning is to ensure that the utility infrastructure is of sufficient size and at the appropriate/required time to provide reliable natural gas service at the design condition*** consistent with reasonable costs.

Facilities investments are required for a variety of reasons; although all investments are predicated on the need to reliably serve system demands at the required customer delivery pressure at the design degree day. Individual facility investments may be required to:

- Maintain system integrity, including the relocation and replacement of existing facilities that no longer meet current class location, safety and operational standards as determined by other engineering criteria.

- Serve growth in peak hourly and peak daily demand on existing systems resulting from attaching new customers, growth in existing customer requirements, and changes in customer usage patterns
- Serve new communities, new subdivisions and main extensions to unserved locations

Often, facilities investment projects are designed to accomplish more than one of these requirements.

Currently, the Gas Utilities develop facility investment plans with multiple-year demand forecasts. The facilities planning process for distribution systems require the estimation of peak hour consumption for each year in the planning forecast. The facilities planning process for transmission facilities requires forecasting of both peak hour and peak daily demand, with an hourly loadshape (profile) that varies the demand for gas over the day.

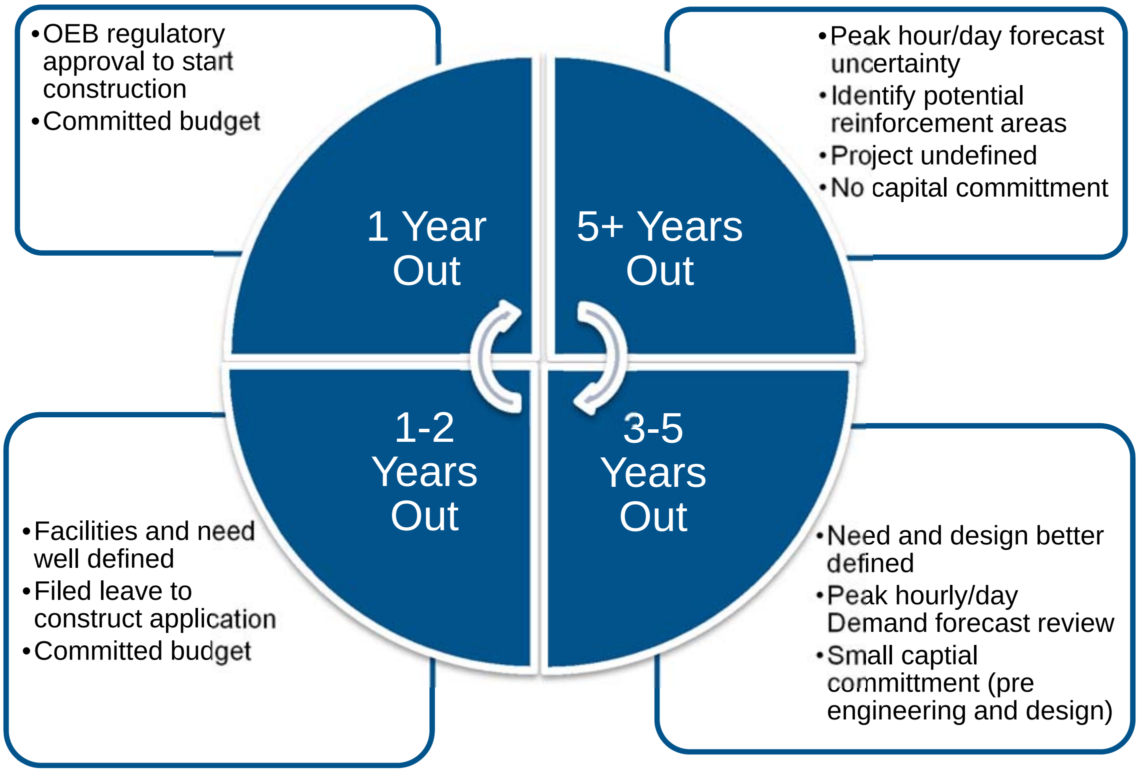
Historical gas use is used as a base to predict future consumption. The planning process includes changes in gas use resulting from historical implementation of DSM measures, as well as other factors such as improved building codes, and higher energy efficiency standards for natural gas equipment. However the facilities plans do not factor in DSM program effects on future peak day or peak hour demand.

The facilities planning process is designed to allow the utilities to proceed with planned investments, or accelerate/defer/revise planned investments depending on how closely customer attachment rates and demand growth match the forecast.

3.2 Facilities Investment Plan Schedules

Facility investment plans consider a multi-year forecast of system growth, as well as known replacement and relocations. The plans are reviewed annually to reflect changes in outlook, and updated as needed, to reflect changes in the forecast and as growth becomes more certain. A typical facilities 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. No capital would be committed at this point. Between three and five years, the forecasts of demand growth are refined, projects with the potential to meet the requirement are identified, capital budgets are developed, and small initial investments are made for engineering, environmental assessments and design. During the period between one and three years prior to the identified need, the project is fully specified, the detailed capital budget is identified, and the gas utility submits for leave to construct. During this period, significant costs are incurred by the gas utility to finalize the engineering, begin land acquisition, go through the leave to construct process, and go through the required permitting and regulatory processes. The facility is built in the final year after the leave to construct is approved by the Board.

Exhibit 2: Facilities Planning Timeline



3.3 Consequences of Insufficient Facilities

Natural gas pipeline systems are designed to serve customer requirements during “design day” conditions. The planning design day is typically based on the coldest winter conditions deemed likely to occur. Under these cold weather conditions, the utility would likely curtail deliveries to interruptible customers consistent with the terms of the contracts signed by these customers.

In the event that the facilities in place are insufficient to be able to deliver the required demand on the design day, the utility will not be able to serve firm customer demand. The utility may not be able to react quickly enough to avoid unplanned customer outages. If there is time, the utility might call force majeure on large volume or power generator customers and / or may choose to shut down entire sections of the distribution system. The curtailment of firm large volume customers would create significant negative economic issues for the affected customers especially if critical equipment is damaged. Shutting power generators could cause broader issues, such as widespread electricity system outages.

If system operating pressure falls below minimum customer requirements, there may be widespread uncontrolled outages. These outages are difficult for utilities to predict and manage. Firstly, these locations need to be identified and isolated by valves from the operating portion of the system. The utility has to physically shut off each customer’s gas meter, and then the affected system needs to be purged of air, if a loss of containment has occurred. Once this is completed, the utility must physically turn on each gas meter and then enter the customers building to inspect and relight each gas appliance at incremental cost. Unlike an electric utility where the system typically re-energizes itself almost immediately after the issue causing the loss of power is resolved, a gas system large scale relight would be expected to take weeks rather than days or hours to resolve. Insufficient infrastructure would lead to a system shut down during the coldest part of the winter, leaving residential and commercial customers without heat during dangerously cold weather. Utilities likely would need to enact emergency plans and would need hundreds of personnel to relight customers. Community emergency plans may need to be activated to move people into warming centers and provide food.

3.4 Forecast of Peak Day and Peak Hour Demand

The facilities planning process for a pipeline system requires the estimation of peak hour and peak day consumption for each year in the planning forecast, as well as an hourly load shape (profile). There are three main customer types in this planning process:

1. **Firm Contract Customers**: Large volume Commercial and Industrial customers which have contracts obligating the utility to provide the customers required hourly and daily firm delivery service. The firm contract customers have hourly and daily gas measurements which increase the accuracy of the estimated customer peak usage.

2. **Interruptible Contract Customers**: Large volume Commercial and Industrial customers which have some or all of their gas requirements contracted as interruptible service. These customers' contracts can include a fixed number of days the utility can call interruptions and require the customer to shut down gas usage. These customers often have alternate fuel capability and switch fuel use from natural gas to the alternative fuel, (which may have a higher GHG or air quality impact), or can shut down processes when called to interrupt by the utility. These customers could be curtailed under design conditions and transmission facilities are not normally installed to maintain service to these customers on design day.

   The Gas Utilities do consider interruptible load in the facilities planning process as they have to ensure that the pipeline systems can accommodate those interruptible volumes during off peak times. Since there may be a fixed number of days where the utility can call interruptions, there may be cases where the pipeline systems need reinforcement to comply with the contracts for these customers.

3. **General Service Firm Customers**: These customers include residential and small commercial and industrial firm service customers. Existing general service customers are assumed to behave in a manner consistent with their recent 24 month weather adjusted consumption behavior. The monthly billing history of each customer is examined and statistical relationships are fit to determine monthly consumption as a function of monthly heating degree days. The utilities use this process to estimate the peak day demand for existing customers at the design degree day.

   Customer usage of gas varies throughout the day and the peak gas usage occurs in the morning hours between 7 and 9 am. The usage is highest during this period as most people start their day at similar times. The highest co-incidence of furnace, hot water and other gas use occurs in the morning.

The facilities planning process forecasts new customer attachments and changes in per customer requirements. New customers are modeled based on a typical average for new customers within each "customer class" (for example a large single-family detached house). The count of new customers is based on historical connection rates plus what is known about specific new large buildings and housing developments.

While the use per customer data that is utilized to project consumption per existing and new customer takes into account recent historical trends, including the impacts from historical energy efficiency efforts, the planning process does not explicitly factor in the impact of future DSM programs on peak day or peak hour consumption.

3.5 Sizing of Incremental Facility Investments

One of the challenges with developing new facility investment projects is determining the future demand and the location of the demand. Economic development, location of new housing developments, and customer types are all difficult to forecast with certainty, creating a range in future demand growth that must be planned for.

There are significant economies of scale associated with the construction of facility investment projects. The cost of the incremental unit of capacity declines as the size of the project increases due to efficiencies in planning, right-of-way and easement availability, mobilization costs, and labor and materials costs.

If the project proves to be undersized relative to future system growth, additional facility investment projects are likely to be much more expensive than increasing the size of the initial project. As a result, the utility, and the utility's customers have a significant economic incentive to plan based on upside uncertainty in the forecast rather than downside uncertainty.

New infrastructure projects can also result in significant disruptions to streets and communities that the projects pass through, leading to a strong incentive to be "one and done" with any project or group of projects. As a result, the timing of facilities investments can be influenced by factors outside the control of the Gas Utilities. In order to be "one and done" investments can be accelerated or delayed to correspond with municipal development schedules related to infrastructure projects such as bridge repair and replacement, road construction or water and sewer repairs and extensions.

The desire to take advantage of other infrastructure projects and the need to minimize community disruptions can lead to upsizing or accelerating facility investments for projects where future expansions would be particularly disruptive or expensive, and may make deferral of some gas infrastructure projects impractical despite the potential for geo-targeted DSM to reduce demand.

3.6 Impact of Reductions in Forecast Demand Growth

Reductions in forecast demand growth can impact facility investment plans in several ways. Generally, a reduction in peak hour load will result in decreased facility investment plans. The change in infrastructure requirements can result in:

- Delay or cancellation of project implementation.
- Decreased diameter of the pipeline.
- Decreased length of pipeline looping to be installed.

For many projects, the amount of capacity added is determined in part by the length of the pipeline project. Growth in a specific location can often be served by a project that eliminates constraints between a supply point and the region with expected demand growth. This rarely requires the construction of an additional pipeline from the supply point all the way to the location of the demand growth. Instead, the incremental capacity can be provided by adding sections of pipe on the most constrained section of the system. Hence, reducing hourly demand growth could also reduce the need for specific sections of new pipe.

4. Differences between Facilities and DSM Planning Criteria and Approach

While DSM programs do broadly impact facilities requirements, and the cost savings associated with a broad based reduction in distribution costs are generally included in the DSM planning process, the linkages between DSM planning and facilities planning are currently passive rather than active, and are not sufficient to actively integrate geo-targeted DSM programs into the facilities planning process. There are a number of differences between the DSM and facilities planning process that must be reconciled in order to potentially use geo-targeted DSM to reduce infrastructure investments. The most important are summarized below.

4.1 Differences in Risk and Reliability Criteria

Perhaps the most challenging difference to address between the current DSM and facilities planning processes is the difference in risk and reliability criteria.

- The primarily goal of the facilities planning process is to ensure the utility distribution system is sized sufficient to ensure that demand will not exceed the system capacity at design conditions. As a result, the facilities planning process is based on a primary philosophy of risk avoidance.
- The primary goals of the DSM program planning process are to reduce annual natural gas consumption and to influence a culture of conservation. DSM success has several metrics but often is evaluated based on program participation rates rather than measurement of actual savings. Risk is inherent in DSM planning and implementation, in part to encourage innovation in program delivery and increase program uptake.

The use of geo-targeted DSM programs to reduce the need for infrastructure projects changes the balance of risk for the DSM program. For a DSM program to be relied upon as an alternative to a new infrastructure investment, it would need to satisfy the same risk criteria as the infrastructure investment that it is replacing. As highlighted in Section 3.3, the facilities planning process risks are not just financial; there are also potential gas system outages if there are insufficient facilities. This is a risk that is not present for standard DSM programs, where the associated risks are strictly financial. As a result, if a geo-targeted DSM program designed to reduce infrastructure investment is non-performing and fails to deliver the expected savings, or if the savings appear to be uncertain during the evaluation phase, the utility will be required to proceed with the infrastructure project in order to ensure the same level of overall system reliability. This would lead to an increase in the overall cost of serving the load growth, as both the DSM costs and the infrastructure costs would need to be recovered. In addition, the infrastructure project may need to be accelerated in order to meet the need, resulting in higher than anticipated or originally budgeted project costs.

4.2 Coordinating Facilities and DSM Planning Timelines for Geo-Targeted DSM Programs

On an operational basis, the DSM planning process operates on a relatively short time-frame. The program planning schedule depends on the type of program, assuming that the program is being implemented in the current DSM framework, and that the policy issues as described in

Section 7 are settled and an appropriate framework is developed. The range of timing from decision on whether or not a program should be implemented to actual implementation ranges from 3 to 12 months. Hence, excluding any regulatory approval delays, the Gas Utilities could be able to implement a new geo-targeted DSM program within 12-18 months of the decision to proceed. This is recognizing that the Gas Utilities have had no experience with geo-targeted program design and these timeframes are based on broad based DSM efforts. The timing may change, as more is known about geo-targeted program design; the Gas Utilities expect to gain insight on these program enhancements during the course of the pilot studies.

The length of time that the DSM program will need to be in place in order to reduce peak demand by enough to delay or avoid a specific infrastructure project will always depend on the specific customer characteristics, the DSM program and the specific infrastructure project. The current lack of information on the ability of natural gas DSM programs to impact peak demand makes it currently impossible to know with certainty when a DSM program needs to be implemented and how long the program needs to be in operation to successfully delay or avoid the infrastructure project. However, the Gas Utilities anticipate that most geo-targeted projects will require two to four years of fully effective implementation to reduce demand growth sufficient to allow the facilities investment to be reduced.

For a geo-targeted DSM program to reduce an infrastructure project, the results of the geo-targeted program would need to be in place with sufficient reliability to ensure that the new facility will not be required to meet demand. Generally, this would require a successful evaluation of DSM program results prior to the time of the leave to construct filing. Given the need to evaluate the impacts of the DSM program, the DSM program would need to be completed or demonstrating measurable results, at least 2 years prior to the date at which the additional capacity provided by the infrastructure project was initially projected to be required.

Hence, a successful geo-targeted DSM program would need to be approved and put into motion about 4 - 5 years prior to the expected in-service date of the targeted facility investment. However, the need for new facilities is generally uncertain at four to five years prior to the in-service date. As a result, geo-targeted DSM programs may need to be implemented before the Gas Utilities have a high degree of certainty that the facility investment will actually be required, potentially leading to an expenditure that may not produce the full value as intended.

4.3 DSM Program Impact Uncertainty

As discussed in sections five and six of this Executive Summary, ICF expects most DSM measures to reduce peak day demand. However, the ability of a given DSM program to achieve a specific level of peak period demand reduction is relatively unknown. As a result, in order to ensure with sufficient reliability for planning purposes that the impact of the DSM program on peak period demand is sufficient to defer a facilities project, the DSM program will need to be designed to achieve greater peak period savings than the facility project that it replaces.

For example, a portfolio of DSM programs might have peak period impacts with a standard deviation of 10% around the expected impact. In order to plan on DSM program meeting the required peak period load reduction 95% of the time, the DSM program would need to be sized to meet 116% of the required capacity. The same program would need to be sized at 121% of the required capacity to meet requirements 98% of the time.

The magnitude of the required oversizing of the DSM program can be influenced by the timing of the DSM program implementation. Earlier implementation of the DSM program would allow for additional monitoring and evaluation, and provide additional assurances that the facility could be constructed before the capacity is required if the DSM program appears unlikely to achieve its objectives. In practice, the optimum planning process is likely to include both oversizing of the DSM programs, and maintenance of the ability to construct the facility if needed, in order to assure required system reliability.

5. DSM Impacts on Peak Day and Peak Hour Demand

ICF leveraged the results of the 2016 OEB Conservation Potential Study (CPS), building modeling, and hourly gate station data from the Gas Utilities to develop load profiles and hours use factors to estimate the winter peak demand breakdown and the achievable winter hourly peak demand for the Gas Utilities for the DSM measures included in the CPS. This included DSM measures that apply to various types of residential, commercial, and industrial sector facilities and equipment. The comprehensive list of energy efficiency measures for the OEB CPS included 52 residential measures, 59 commercial measures, and 57 industrial measures. The scope of the DSM measures included higher efficiency equipment, such as condensing boilers and tankless water heaters, envelope measures, such as air leakage sealing and attic insulation, and controls measures, such as adaptive (smart) thermostats and demand control ventilation.

5.1 DSM Impacts on Peak Day and Peak Hour by Sector

Although ICF's analysis focused primarily on the peak hour, which was found to occur from 7-8 am in all regions, peak demand impacts across five peak periods were considered. This included each hour of the morning lift period between 6 am and 10 am (including the peak hour) and the entire peak day, considered as an aggregate.

The broad-based DSM impacts on peak day and peak hour demand by sector (residential, commercial, industrial) are summarized below. For each sector, the analysis identified which sub-sectors and end-uses have a larger relative impact on the achievable peak demand savings.

5.1.1 Residential Sector Results

The residential sector included all homes except for multi-unit residential buildings (MURBs or apartment buildings). ICF's analysis indicated that the highest peak demand savings potential in the residential sector occurs during 9-10 am and that adaptive thermostats could lead to an increase in peak demand during the peak hour (7-8 am). Other high-level results for the residential sector analysis can be summarized as follows:

- Low income homes represent a disproportionately large share of peak hour savings relative to peak hour demand due to the age and the nature of the housing stock
- Space heating measures are quite important from a peak demand perspective since they have both a higher relative impact and a higher savings potential
- The top three residential peak demand measures are all related to air tightening the building envelope

5.1.2 Commercial Sector Results

ICF's analysis indicated that the highest peak demand savings potential in the commercial sector occurs during 6-7 am, although the savings potential during this period is only slightly higher than the peak hour (7-8 am). Other high-level results for the commercial sector analysis can be summarized as follows:

- Subsectors that are more important from peak hour savings perspective include Offices, Education, Retail, Other.

- Low income apartments have a relative large peak hour savings potential relative to Reference Case due to the age and the nature of the housing stock.
- Space heating is the most important end use but there is also significant potential in DHW.
- Space heating measures, such as high efficiency boilers, condensing boilers, and condensing makeup air units (MAUs), are important from a peak hour savings perspective.

5.1.3 Industrial Sector Results

ICF's analysis indicated that the highest peak demand savings potential in the industrial sector occurs during 6-7 am, although the savings potential during this period is only slightly higher than the peak hour (7-8 am). Other high-level results for the industrial sector analysis can be summarized as follows:

- Manufacturing facilities and greenhouses/agriculture are more important as compared to other industrial customers from a peak hour savings perspective.
- Demand savings from mineral processing industries are less concentrated during the peak hour, but are still important due to the high percent savings that can be attained.
- The HVAC and Other end-use is quite important from a peak demand savings perspective since the demand and savings potential is focused on the winter peak hour.
- Space heating measures are important to consider in the industrial sector as well if the goal is to reduce winter peak demand.

5.1.4 All Sectors

The aggregated results for all sectors indicated that the highest peak demand savings potential occurs during 9-10 am, although the savings potential during this period is only slightly higher than the peak hour (7-8 am).

- ICF's analysis suggests that DSM is not expected to shift the timing of hourly peak demand.
- Compared to the Industrial sector, the achievable savings for the Commercial and Residential sectors are slightly more concentrated during the peak demand hour.
- The Industrial sector can achieve a much higher percent savings compared to the Commercial and Residential sectors.

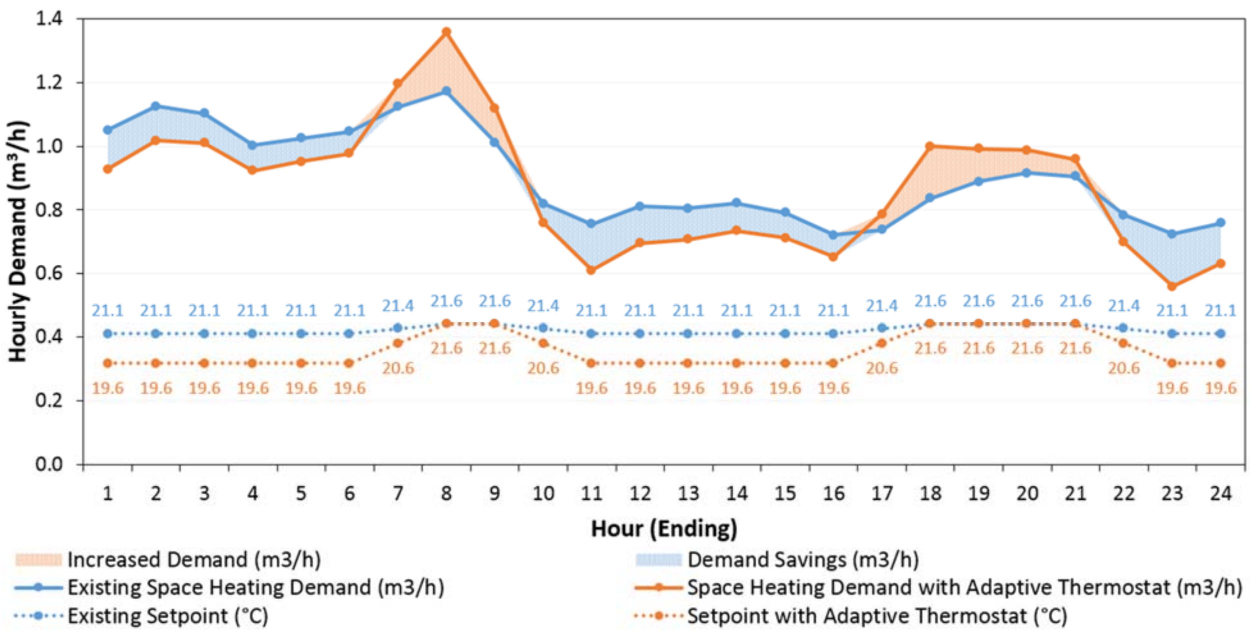
5.2 DSM Measures of Interest

The majority of energy efficiency measures were found to reduce both annual load and peak hour load. However there were a few measures that had the potential to increase the peak hour load on a distribution system, even though they did contribute to a decrease in annual consumption. Adaptive thermostats and tankless water heaters were investigated in detail due to their significant annual savings potential and the complexity associated with their potential impacts on peak demand. The results of the analysis on these measures and the broader DSM impacts on peak day and peak hour demand are summarized below.

5.2.1 Adaptive Thermostats

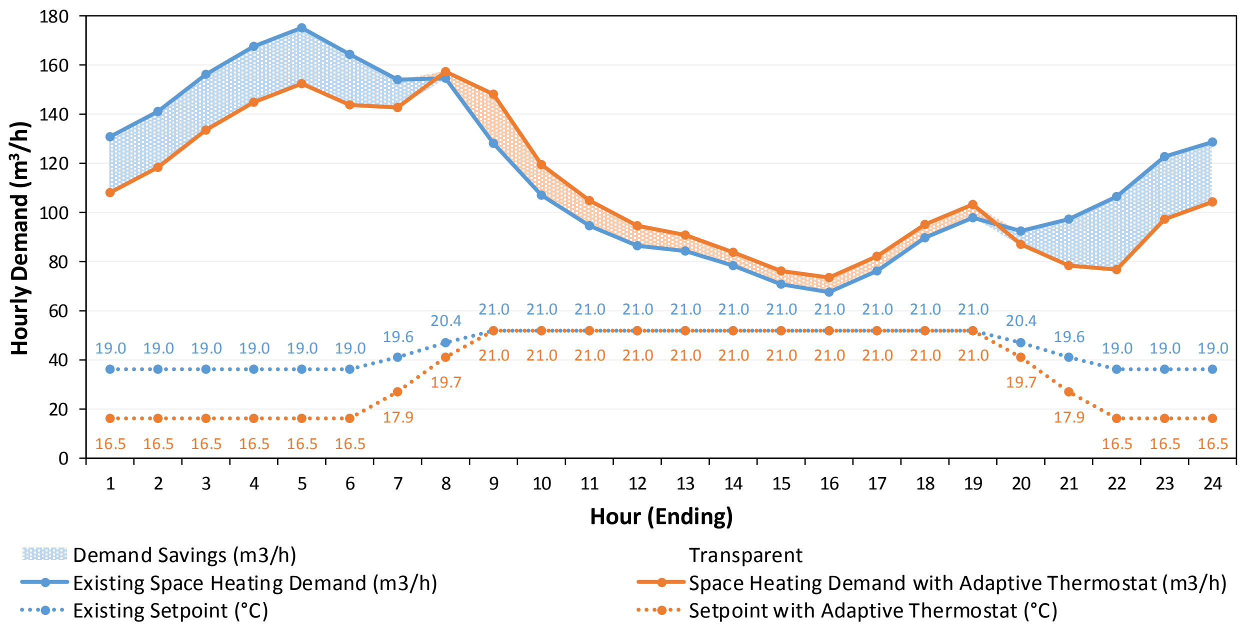
Adaptive thermostats account for a significant amount of the achievable DSM potential in both the residential and commercial sectors. According to the ICF CPS, in Ontario, adaptive thermostats account for 21.5% of the Business As Usual (BAU) Achievable DSM savings (44.8% of residential, and 2.62% of commercial). Although this measure leads to annual gas savings, building modeling suggests that adaptive thermostats contribute to increased demand during winter peak hour periods. These periods of increased demand occur when heating systems are recovering from temperature setback. Exhibit 3 demonstrates the demand impacts resulting from the implementation of adaptive thermostats in the residential sector during design day conditions. As shown in the exhibit, residential building modeling indicates that adaptive thermostats lead to a significant increase in winter peak hour demand in the residential sector.

Exhibit 3: Residential Sector Hourly Demand Comparison for Adaptive Thermostats



Commercial building modeling also suggested that adaptive thermostats lead to increases in winter peak hour demand in the commercial sector but, as demonstrated in Exhibit 4, the impact is much smaller than the residential sector. This is due to the lower applicability of this measure in the commercial sector and the diversity of operating schedules in the different types of commercial facilities being considered.

Exhibit 4: Hourly Demand Comparison for Adaptive Thermostats Applied to Offices



In both the residential and commercial modeling results, it can be seen that adaptive thermostats lead to increased demand during other non-setback hours during the winter peak day since it can take several hours to heat up a building's entire thermal mass. The results of this analysis suggest that, where adaptive thermostats are deployed on a broad basis, their impacts on a natural gas distribution system would need to be closely monitored. In the residential sector in particular, adaptive thermostats appear likely to lead to increases in distribution capacity requirements.

It is important to note that adaptive thermostats can be integrated into demand response (DR) programs to help mitigate peak demand increases during peak hours. Based on recent consultations completed by ICF,[5] thermostat manufacturers including Nest, ecobee, and Honeywell indicated that they run a large number of DR programs. Although these programs are typically focused on summer peak reduction, the thermostat manufacturers indicated that DR program focused on winter peak reduction are feasible..

5.2.2 Tankless Water Heaters

Typically, tankless water heaters have a much higher rated maximum natural gas consumption rate than standard water heaters. The potential increase in peak natural gas consumption by these appliances raised initial concerns that even though tankless water heaters would reduce annual and peak day natural gas consumption, they might increase peak period consumption. Only limited measured data is available on the impact of tankless water heaters on peak period natural gas demand. As a result, ICF used building modeling techniques, combined with the available data to estimate the impacts.

ICF modeling using metered DHW consumption profiles at 5 minute intervals suggests that tankless water heaters can increase peak demand during the relatively short periods that they

[5] ICF, Compatibility Study: Smart Learning Thermostats, completed on behalf of FortisBC, April 10, 2017.

are in use. However, on an aggregate basis for a community, ICF's analysis suggests that tankless water heaters contribute to hourly winter peak demand savings; especially if the diversity of hot water consumption is considered.

Exhibit 5 and Exhibit 6 summarize the results of ICF's modeling, which compared the demand draw of tankless water heaters and storage water heaters for a community of homes with heavy hot water usage. As depicted in Exhibit 5, there are brief instances where the aggregate demand for the community increases if demand is considered on 5-minute increments. However, Exhibit 6 demonstrates that, if demand is averaged out over 60-minute increments, tankless water heaters are consistently resulting in demand savings for the community. ICF's modeling was based on 5-minute interval hot water consumption data for homes with high hot water consumption and different types of hot water usage patterns.

Exhibit 5: Comparison of Water Heater Demand for Community with Heavy Hot Water Use, 5-Minute Intervals

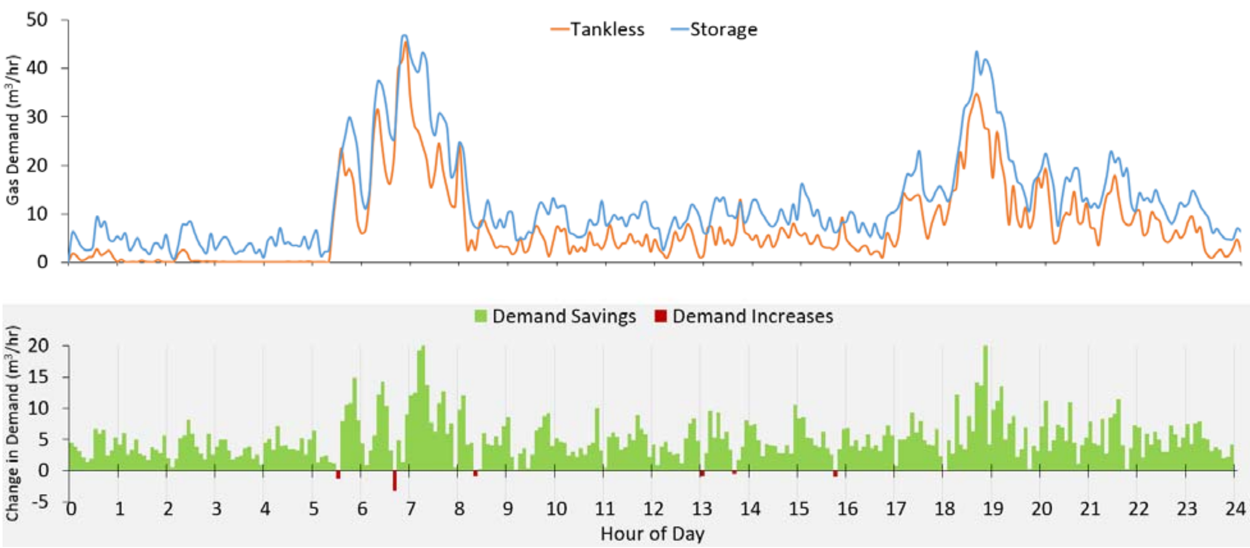
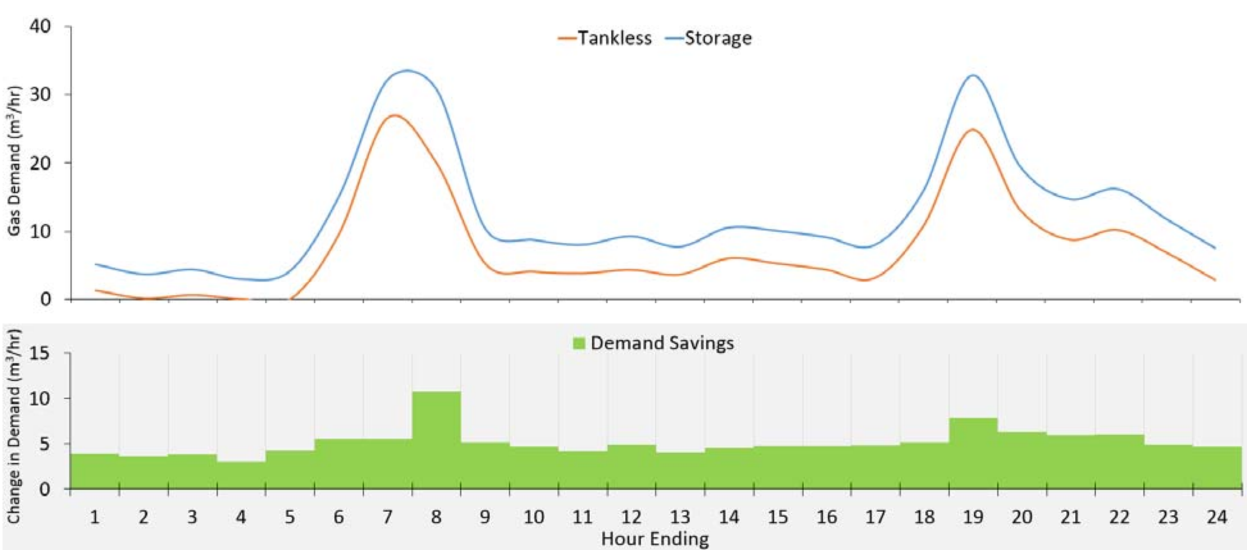


Exhibit 6: Comparison of Water Heater Demand for Community with Heavy Hot Water Use, 60-Minute Intervals



6. Potential Impacts of DSM on Facilities Requirements

ICF leveraged the results of the DSM impacts analysis described in Section Five to evaluate the potential of DSM programs to impact peak period demand and to reduce infrastructure investments.

As part of this step in the process, ICF worked with utility staff to identify appropriate hypothetical case studies based on specific examples of utility infrastructure investments. Information from these case studies that fed into the analysis included project costs, current and forecasted capacity requirements, and the distribution of energy consumption by facility type. The DSM supply curves were used to compare the costs of peak demand reduction through the implementation of DSM against infrastructure project costs.

6.1 Peak Hour DSM Supply Curves

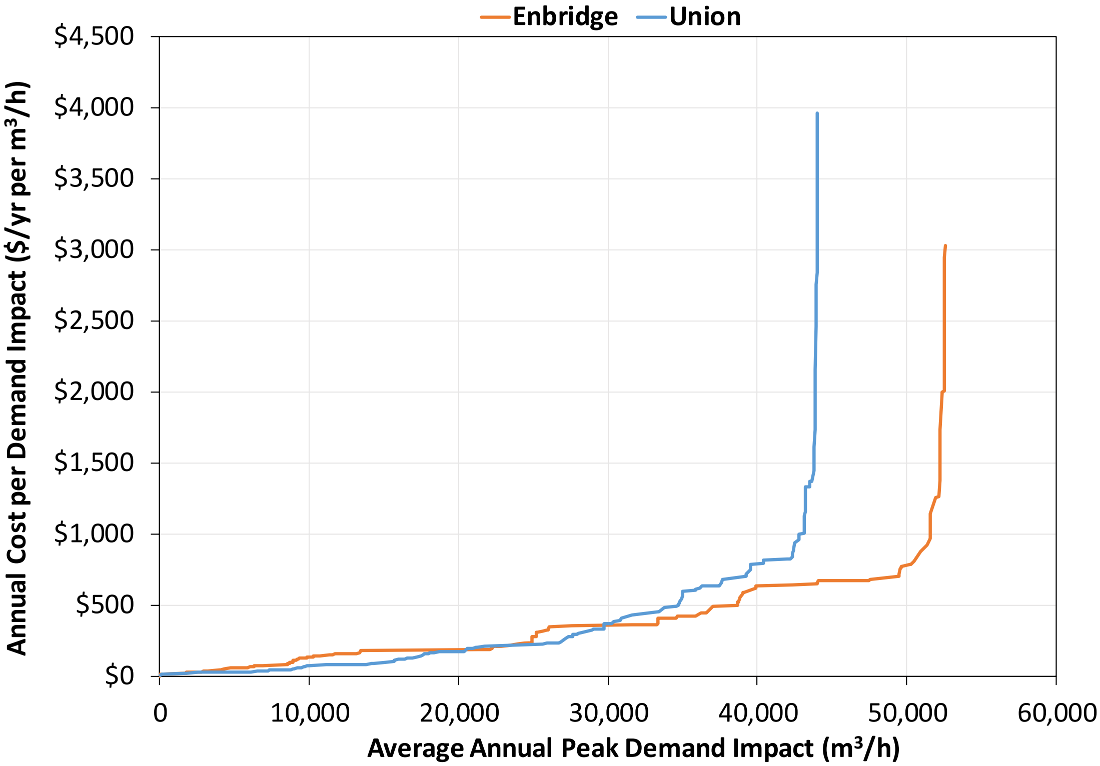
The peak hour DSM supply curve for each utility shows the relative DSM program cost (i.e. \$ per m^3/h) to achieve the estimated peak hour demand impacts in each utility service territory. The DSM supply curves prioritize the measures based on their cost-effectiveness, based on the cost per unit gas demand savings, with the most cost-effective measures being implemented first. Each of the DSM supply curves includes measures from all of the sectors being considered (i.e. residential, commercial, and industrial). For the residential and commercial sector, each measure is split into two parts, with the Business As Usual (BAU) scenario reflecting the impacts that can be achieved based on modest incentives and the aggressive scenario demonstrating the incremental demand impacts and costs based on high incentive levels. Costs and savings were aggregated for each of the industrial sector measures since these measures were generally found to be much more cost-effective and there was limited value in splitting out the BAU and aggressive scenarios.

The program costs used to develop these DSM supply curves are composed of both incentive and non-incentive costs. Incentive costs are based upon the estimated level of incentive required to influence measure adoption, while non-incentive costs are administrative costs for program delivery activities, including items such as marketing and labour for program staff.

The most cost-effective measures on the DSM supply curves include industrial measures to optimize and have increased control of existing systems (as further outlined in section 6.3.1 below) which suggests that these measures should be implemented first if the goal is to reduce winter peak hour demand. Conversely, residential and commercial measures make up most of the least cost-effective measures (as outlined further in section 6.3.1) and would be a lower priority under a winter peak hour demand program.

The potential peak hour demand impact potential of 44,035 m^3/h per year in Union Gas territory (as shown in the exhibit below) represents an annual average savings of approximately 1.24% over the total hourly reference case demand of approximately 3.54 million m^3/h. For the Enbridge Gas service territory, the potential peak hour demand impact of 52,546 m^3/h per year represents an average annual savings of approximately 1.05% over the total hourly reference case demand of approximately 5.01 million m^3/h. The differences between the Enbridge Gas and Union Gas service territories is largely driven by differences in customer mix. Union Gas, with a higher percentage of industrial demand has somewhat more DSM potential.

Exhibit 7: Broad-Based DSM Supply Curve for EGD & UG



The application to specific projects will depend on the customer mix in the specific service territory served by the investment project. In the case studies reviewed below, the potential peak hour demand impact ranged from about 0.8% per year to 1.35% per year.

6.2 Application of DSM Supply Curves to Facility Investments

The peak hour DSM supply curves that ICF constructed leveraged measure-specific estimates of peak demand impacts and program costs. The numbers employed in these DSM supply curves are based on broad regional averages, including the distribution of different types of facilities, and the best available data on the penetration of different types of energy efficiency measures across each utility's service territory.

These DSM supply curves were used to estimate the peak demand impacts resulting from the implementation of DSM at the level of an individual facility investment, despite the obvious limitations with this approach, including a significantly larger degree of uncertainty with the results. One item that warranted special attention was the program costs associated with implementing DSM at the geo-targeted (i.e. community) level. Simply scaling the program costs from the broad-based analysis to estimate the geo-targeted program costs ignores the fact that there are efficiencies of scale associated with implementing DSM programs across a large service territory and these will not translate to geo-targeted programs. Essentially, although incentive costs can be scaled despite the size of the program, admin costs would be much higher for geo-targeted programs.

Geo-targeted DSM programs would tend to be smaller than most broad-based DSM programs and even for an equivalent program size (i.e. $/yr.), geo-targeted programs will be more expensive per unit impact than broad-based DSM programs due to several factors, including the need for metering and on-going monitoring of impacts. Based on the review of a 2014 ACEEE study,[6] which included an assessment of the annualized costs of implementing natural gas DSM program in a large number of US jurisdictions and provided a sense for how much these costs vary, and ICF's experience with implementing DSM programs across North America, ICF estimated that the cost of implementing geo-targeted DSM programs would be in the range of 1.5 - 2 times more expensive than implementing broad-based DSM programs, on a per unit savings basis. As such, the cost of implementing geo-targeted DSM programs is presented as a band.

The Gas Utilities staff also provided details pertaining to example facility investment projects, including associated costs, existing and projected system peak demand, and the best available data regarding the breakdown of peak demand by different types of facilities. These example facility investment projects were used as case studies to assess the theoretical potential costs and benefits of using DSM to reduce infrastructure investment. The broad peak hour DSM supply curves were scaled to match the demand of these case study facility investment projects, including the distribution by facility type. The resulting DSM supply curves were used to compare the estimated cost of peak demand reduction from DSM measures against the cost of facility investments for these example case studies.

6.3 Accounting for Other Costs and Benefits from DSM Programs

6.3.1 Reduction in Annual Natural Gas Demand

The primary design objective of DSM programs designed to reduce infrastructure investment would be to reduce peak period demand. However, DSM programs implemented with the goal of impacting peak will also save avoided costs associated with annual energy efficiency including gas commodity cost savings, upstream capacity costs and the value of non-energy benefits including the value of the carbon emission reductions. ICF's analysis does not account for any additional benefits. How various savings would be valued in an IRP context will require additional analysis.

6.3.2 Duplication of DSM Benefits

The DSM supply curves incorporate all of the DSM measures included in the 2016 OEB Conservation Potential Study that are capable of reducing peak period demand. Many of these measures will be available to the Gas Utilities' customers through existing broad-based DSM programs. ICF did not attempt to separate out the impact of broad-based DSM programs when developing the initial DSM supply curves for geo-targeted programs in this initial study. Since the natural gas demand forecasts used to develop infrastructure investment plans are based on demand data that includes the impact of existing DSM programs, the current DSM supply curves likely overstate the potential incremental reduction in peak period demand available for geo-targeted DSM programs.

Determining the best approach to eliminating the duplication of DSM benefits is expected to require additional analysis, and may require an assessment on a case by case basis.

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[6] Molina, Maggie, ACEEE, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs, Report #U1402, March 2014.

6.4 Intersections between DSM and Infrastructure Planning

The Gas Utilities identified three areas where the intersection between DSM programs and the infrastructure planning process could impact (reduce) infrastructure costs.

1. **Broad Based DSM Impacts on Infrastructure Planning Reinforcement Projects (Passive Deferral)**
   All DSM programs have the potential to impact peak hourly and peak daily demand and to change the need for new infrastructure investment regardless of whether or not the programs are specifically designed to reduce peak hourly or daily demand.[7] This is referred to as passive deferral of infrastructure investment.

   The impact of historical broad based DSM programs on infrastructure investment is inherently captured in the facilities planning process. Customer usage is updated each year using consumption based on recent historical usage. The historical usage used in the process reflects the impact of past and current broad based DSM once it has materialized, but it does not reflect anticipated or unknown future DSM program impacts.

   Passive deferral of infrastructure investment based on broad based DSM activity requires two basic components to be accurately captured in the facilities planning process.

   - Use of appropriate avoided infrastructure investment cost estimates that fully value the potential costs and benefits associated with deferral of facilities investments by utilizing DSM programs.
   - Accurate consideration of the expected impacts of Energy Efficiency measures and DSM programs on the peak hour and peak day demand forecasts used to evaluate the need for infrastructure investments.

2. **Geo-Targeted DSM Impacts on Facilities Planning for New Subdivisions or Community Projects**
   The final type of infrastructure investments that might be affected by DSM are expansions to serve new communities or subdivisions. Serving new communities typically requires a significant investment in new pipeline capacity to deliver gas to the community, as well as reinforcements on existing parts of the system to meet the growth in overall requirements.

   Given the nature of a new community expansion, where the project is necessary to provide the initial gas service to the community, DSM programs would not be useful in *deferring* the facility investment. However, in certain circumstances, the overall magnitude of the investment and project might be reduced if the DSM programs alone or in conjunction with other Distributed Energy Resources are capable of reducing the expected demand in the new community.

[7] Not all DSM measures will impact peak hour or peak day demand in the same way. Most DSM measures are expected to reduce peak hour and peak day demand, although the relative magnitude of the impact will differ by some measure. Adaptive thermostats are expected to reduce peak day demand but increase peak hour demand. Other DSM measures may have no impact on peak hour or peak day demand.

3. **Geo-Targeted DSM Impacts on Infrastructure Planning Reinforcement Projects (Active Deferral)**
   DSM programs that target peak hour and peak day demand reductions in specific areas where infrastructure investments are planned have the potential to delay, or avoid the need for the infrastructure investment. Use of Geo-Targeted DSM programs to reduce specific infrastructure projects requires three key steps:

   - Identifying infrastructure projects that could be reduced by a reduction in peak hour or peak day demand.[8]
   - Designing and implementing cost-effective DSM programs capable of reducing peak hour or peak day demand sufficient enough to reduce the infrastructure project within the available time frame.
   - Verifying the effectiveness of the DSM programs on a time line sufficient to ensure that infrastructure project can be reduced without impacting the Gas Utilities' ability to reliably serve natural gas system demand.

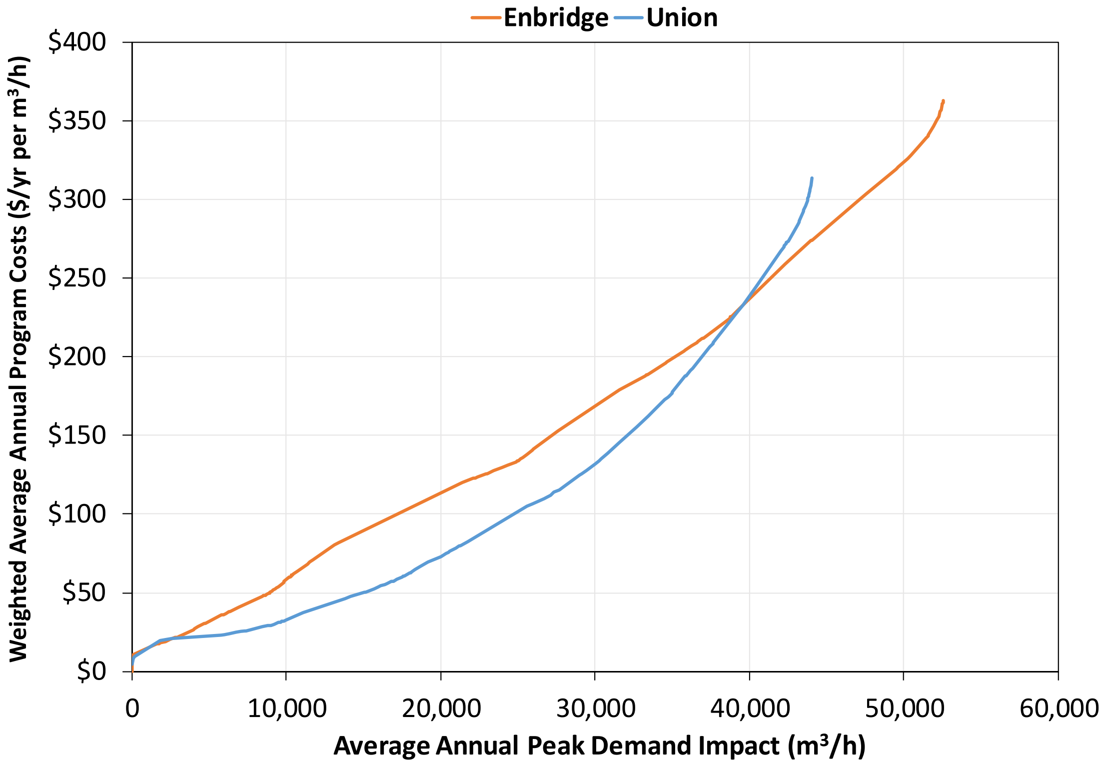
6.4.1 Broad-Based DSM

The peak hour DSM supply curve for each utility is presented below showing measures from all the sectors being considered (i.e. residential, commercial, and industrial). The broad-based analysis curves show the cost of implementing DSM measures against their demand savings impacts. Section 6.1 presented the broad based DSM supply curve showing annual program costs on the vertical axis and the average annual peak demand impact (m^3/h) on the horizontal axis. Exhibit 8 presents the annual weighted average cost per unit demand impact, essentially demonstrating the weighted average program cost and savings that would be associated with implementing a program starting with the most cost-effective measure.

The majority of the industrial measures are at the bottom of the DSM supply curves presented in Exhibit 8, with some commercial and residential behavioral, optimization and control type measures also on the lower end of the supply curve for both Gas Utilities. Examples of some of the most cost-effective measures include industrial measures such as reduce boiler steam pressure, burn digester gas in boilers, regenerative thermal oxidizers, and ventilation optimization (ranging from an estimated annual $4-23 per m^3/h). Commercial measures including ventilation fan VFDs and ozone laundry treatment are also very cost-effective (estimated annual costs of $9-11 per m^3/h and $18-26 per m^3/h, respectively).

[8] Many infrastructure investments are driven by pipeline integrity requirements, class location and/or municipal replacement requirements, and would not have the flexibility to be delayed or avoided.

Exhibit 8: Broad-Based DSM Supply Curve for EGD & UG – Weighted Average Annual Program Costs[9]



Measures that were found to be the least cost-effective are mostly commercial and residential sector measures. This includes commercial measures such as wall insulation, ENERGY STAR clothes washers, and advanced BAS/controllers, each with estimated annual costs greater than $300 per m^3/h.

6.4.2 Community Reinforcement

The Gas Utilities staff provided details based on a criteria provided by ICF pertaining to case study facility investment projects. ICF scaled the broad-based DSM supply curves to create the community-level supply curves. These scaled-down curves allowed for a comparison of the estimated cost of peak demand reduction from DSM measures against the cost of facility investments.[10] Furthermore, the following approach was taken to compare the facilities investment projects to DSM:

- The full annual investments (program costs, including both incentives and admin) for DSM were modeled on an extended timeframe.

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[9] In Exhibit 8, the broad-based DSM program costs have been annualized over the lifetime of the DSM measures. As such, the annual DSM program costs cannot be calculated by multiplying the Weighted Average Annual Program Costs by the Average Annual Peak Demand Impact. In this particular example, the cost of implementing DSM to defer 40,000 m^3/h of growth in Union's service territory is estimated at approximately $98,975,000, and the peak demand impact of individual measures would persist from 1 to 30 years (the weighted average lifetime of the measures is approximately 15.2 years).

[10] As noted in Section 6.2, program costs were scaled up by a factor of 1.5-2 to account for the fact that admin costs related to running a geo-targeted program would be significantly higher than the admin costs associated with a broad-based DSM program portfolio.

- It was assumed that DSM would start being implemented 3 years ahead of a facility investment project.
- The net present value of the DSM program costs were compared against the net present value of the infrastructure investment costs.

Exhibit 9 presents the geo-targeted DSM supply curve for a community reinforcement project located in Enbridge's Central region. Based on information provided by the utility, the total capital cost of this project is approximately $8,200,000 and it involves the installation of 3.2 km of NPS 12" ST HP pipeline. As shown in Exhibit 9, ICF's analysis for this particular scenario suggests that the present value of the costs associated with running a geo-targeted DSM program is slightly lower than the present value of the costs associated with the reinforcement project. In other words, it may be more cost-effective to launch geo-targeted DSM program than to install the reinforcement project. This finding is primarily a result of the high capital costs of the reinforcement project and the relatively small demand growth rate in this community (i.e. 0.5% annually).

Exhibit 9: Supply Curve for Reinforcement Project in Enbridge's Central Region

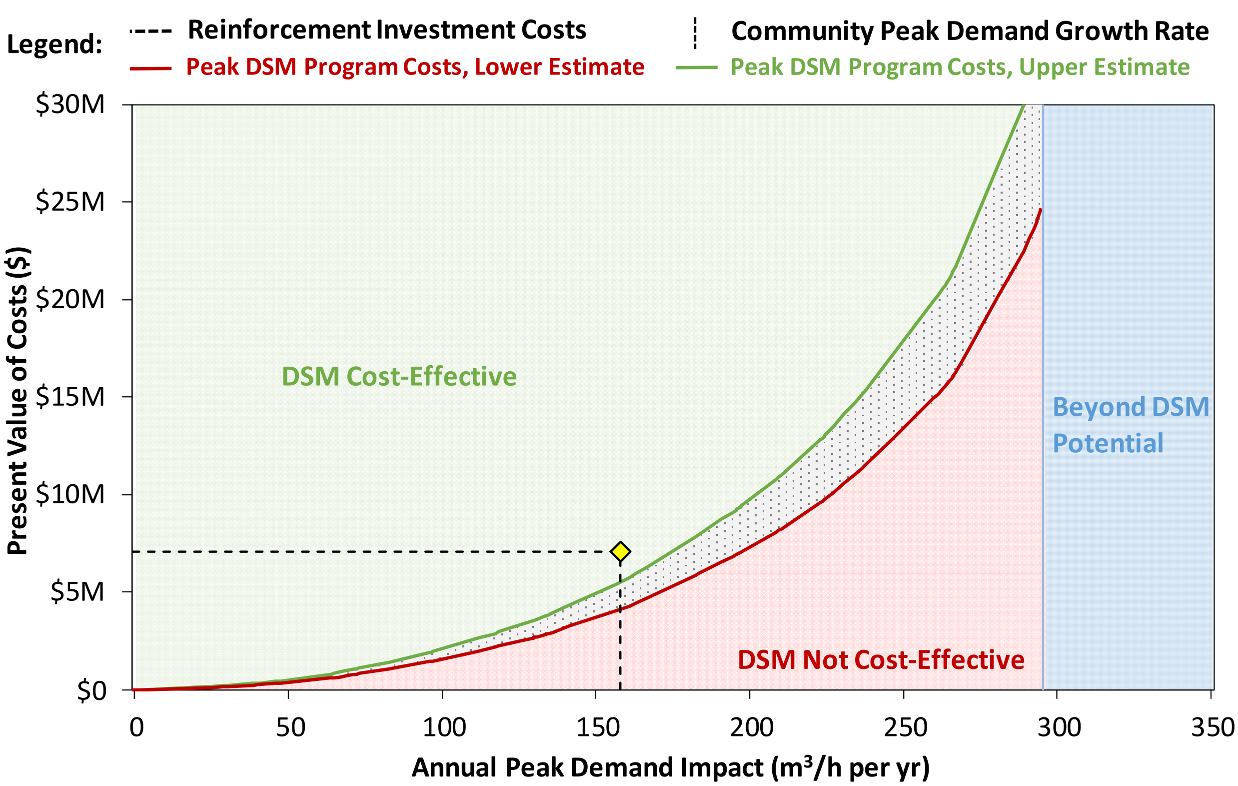
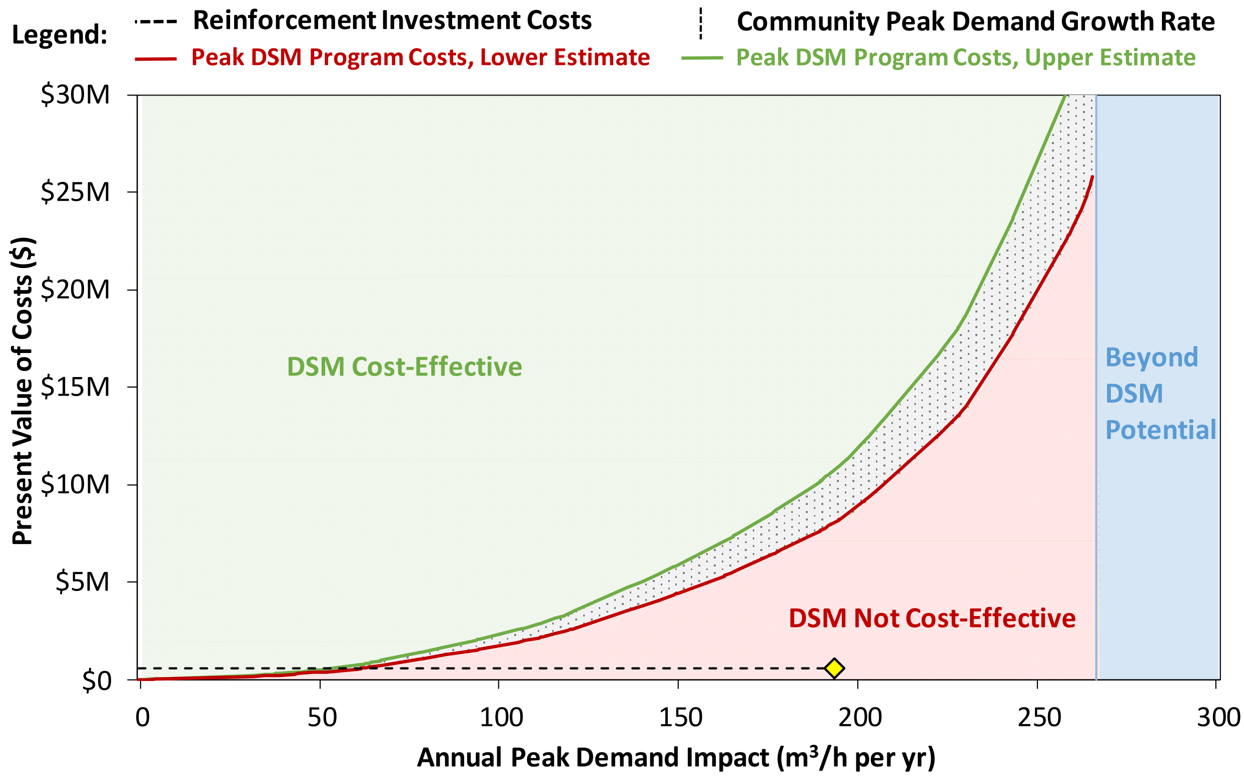


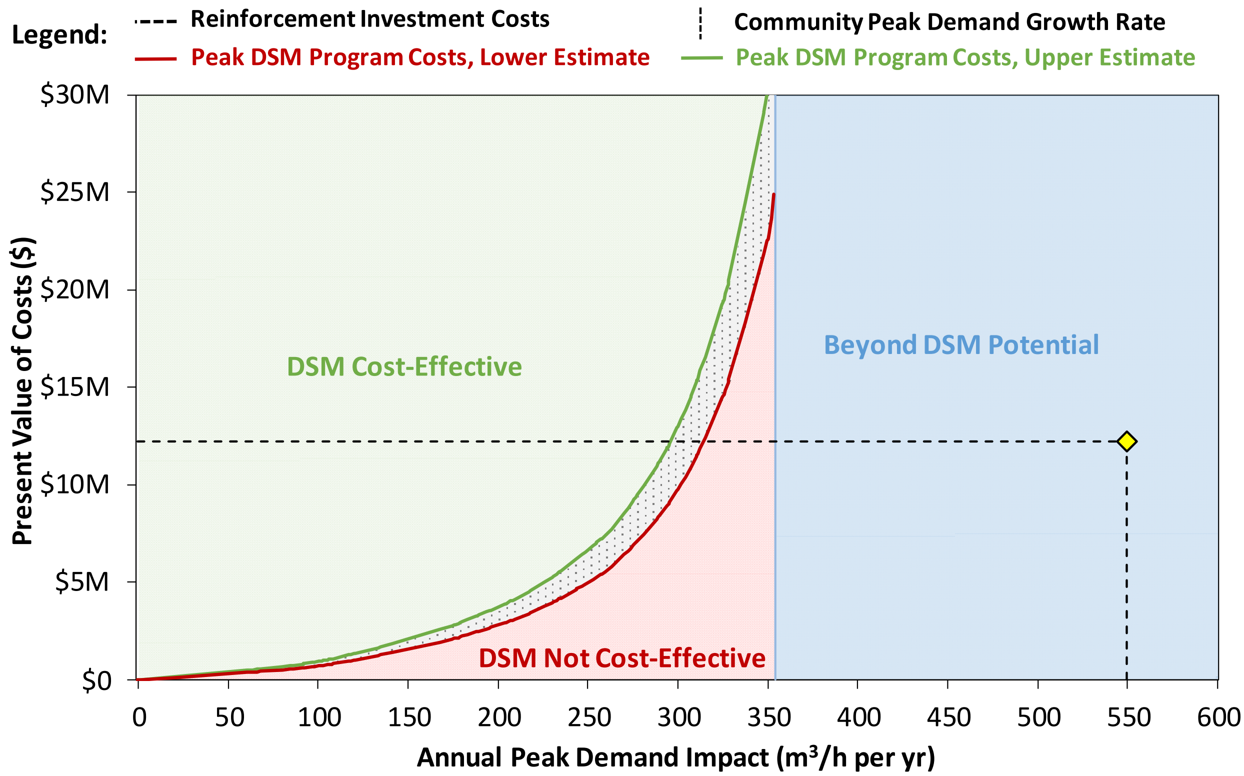
Exhibit 10 demonstrates that DSM is not always a cost-effective option for deferring reinforcement projects. In this case, Union Gas is planning to install 1.3 km of NPS 6" ST 6895 kPa pipeline to accommodate a growing community whose peak demand is increasing by approximately 194 m^3/h annually (0.7% per year). Although ICF's analysis suggests there is enough DSM potential to offset this growth, Exhibit 10 illustrates that it would not be cost-effective to defer the reinforcement project with a geo-targeted DSM program due to the lower capital costs of the project ($690,000) relative to the cost of the geo-targeted DSM.

Exhibit 10: DSM Supply Curve for Reinforcement Project in Union's North Region



A third scenario could also arise when comparing a reinforcement project to a geo-targeted DSM program aimed at reducing peak demand: there may not be enough DSM potential to offset the peak demand growth rate of the community. Such a scenario is depicted in Exhibit 11, which compares the costs of a reinforcement project in Union Gas' southern region against the costs of a geo-targeted DSM program. This reinforcement project would involve the installation of 7.6 km of NPS 12" ST 6160 kPa pipeline at a cost of $14,100,000. However, the peak demand of the community is expected to grow by 2.6% annually (~550 m^3/h), while ICF's analysis suggests that a geo-targeted DSM program would only be capable of offsetting ~355 m^3/h of growth annually, or about 1.35% growth per year in this market (approx. 295 m^3/h) at the same NPV cost as the infrastructure investment project. For this scenario, a geo-targeted DSM program could not feasibly defer the reinforcement project, and would also not be practical from a financial perspective, as shown in Exhibit 11.

Exhibit 11: DSM Supply Curve for Reinforcement Project in Union's South Region

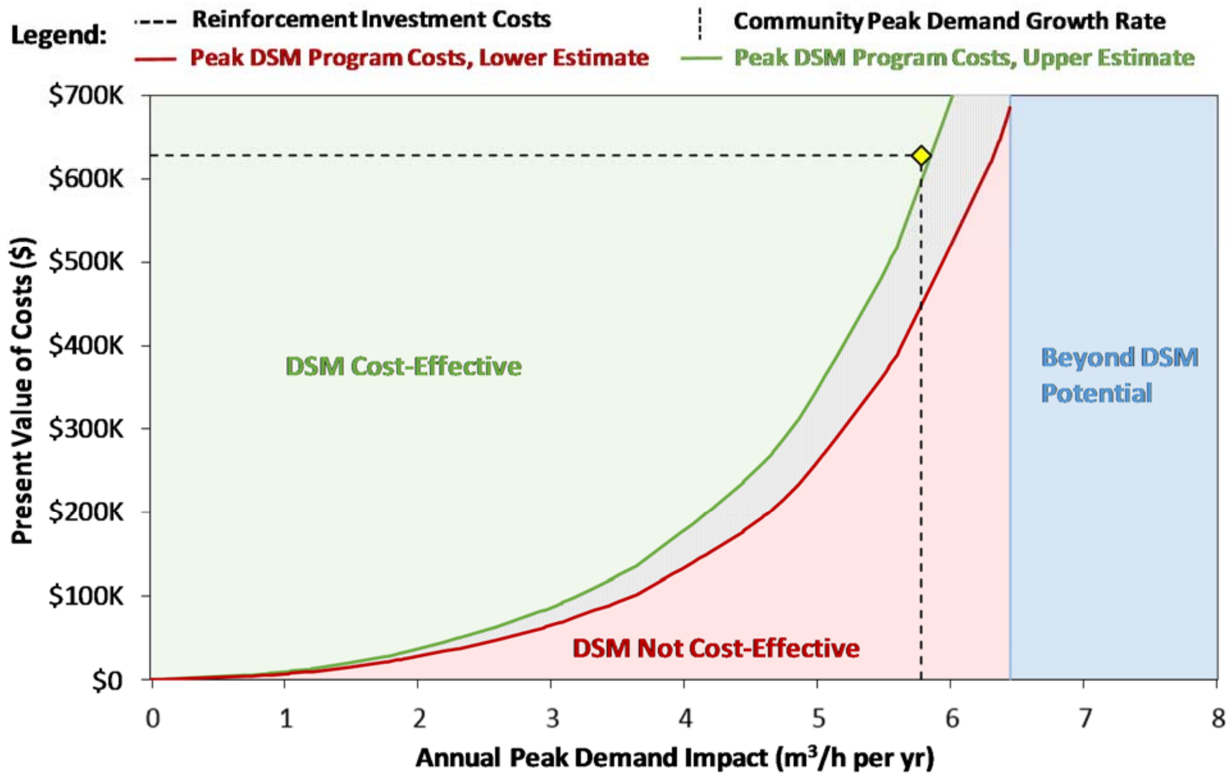


6.4.3 New Community Expansion

In addition to reinforcement projects, this study also investigated the potential for DSM to reduce capital costs for new community expansion projects. Of particular interest was the scenario where the demand from the new community is expected to be near the maximum capacity of a specific pipe size. Exhibit 12 shows the supply curve for such a hypothetical situation, wherein a NPS 2" steel pipe can be installed for $5,275,000, but would barely meet the new community's peak demand of 675 m^3/h. Alternatively, a NPS 4" steel pipe can be installed for $6,000,000 to comfortably meet the community's peak demand for many years to come (i.e. peak demand capacity of 4,160 m^3/h).

As shown in Exhibit 812, ICF's analysis suggests that DSM can cost-effectively offset annual peak demand growth of up to 5.8 m^3/h (or about 0.8% per year) in this market. If the peak hour demand for the community is growing faster than this rate, DSM would not be able to cost-effectively offset this growth.

Exhibit 12: Supply Curve for a New Community Project in Union's South Region



6.4.4 Summary of Results and Practical Considerations

The DSM measure supply curves reflect ICF's best current assessment of the costs and impacts on peak period demand available from DSM programs, while the facilities costs reflect the potential cost of serving incremental demand growth via investments in new facilities. As indicated in the summary analysis, there are facilities investments where the incremental cost of reducing load using geo-targeted DSM programs may be lower than the incremental cost of the facilities, when compared strictly on a $ per m^3/h of incremental capacity provided. Hence, ICF's analysis of the potential for geo-targeted DSM to reduce peak hour demand growth suggests that under certain circumstances, there may be potential to reduce infrastructure investments using geo-targeted DSM programs.

However, there are a number of factors that need to be considered when making a project specific comparison of the cost of geo-targeted DSM and the cost of new facilities. These include:

- **Other benefits of facilities projects:** Many facilities projects provide additional reliability and flexibility to the natural gas distribution system in addition to increasing capacity. For projects where system reliability and flexibility are a significant factor in project design, the cost of the project needs to be allocated between the increase in capacity and the other project benefits.
- **Reliability of DSM programs to reduce peak demand:** To be useful in reducing infrastructure investments, geo-targeted DSM programs must achieve the same level of reliability as the infrastructure investments that they are designed to reduce. In the short

term, the uncertainty regarding the cost and reliability of geo-targeted DSM programs limits the Gas Utilities' ability to rely on geo-targeted DSM programs during infrastructure planning.

- **DSM penetration rates:** ICF's analysis suggests that, on average, the maximum achievable potential for peak demand savings from aggressive DSM implementation ranges from about 1.05% of peak demand per year in the Enbridge service territory to 1.24% of peak demand per year in the Union Gas service territory.[11] Based on the initial Enbridge facility investment data reviewed by ICF, when measured by the amount of incremental capacity being added, only about 20% of the planned facility expansion projects[12, 13] fall below this level.

- **Short Term Project Deferral:** In some cases where the projected growth in peak period demand exceeds the potential annual savings available from DSM, aggressive implementation of DSM might be sufficient to delay the project for a period of time without obviating the eventual need for the project. This would require implementation of the DSM program early in the facilities planning process in order to accumulate sufficient DSM savings to delay the facility. The cost effectiveness of using DSM to delay the project depends to a significant degree on the length of time that the project can be delayed. A relatively short delay (one to three years) is unlikely to be useful due to the potential risk associated with the timing of the project and the need to monitor DSM program impacts, to ensure that the facilities are in place when needed.

- **Size of the geo-targeted community:** As with all DSM programs, geo-targeted DSM programs will benefit from economies of scale. As a result, as facility investment projects decline in size, the cost per m^3/h of peak demand savings from DSM is expected to increase, and smaller projects are unlikely to be cost-effective.

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[11] Some of this potential may not be available for geo-targeted DSM programs due to its inclusion in pre-existing broad-based DSM programs.

[12] The planned facility expansion projects reviewed by ICF represent the list of potential expansion projects at a specific point in time, and should not be considered representative of future capacity expansion projects.

[13] The planned facility expansion projects represent a subset of facilities investments, and include only those projects with the primary objective of meeting growth in natural gas demand.

7. Policy Considerations

ICF's review of the DSM and infrastructure planning processes at the Gas Utilities has identified several potential barriers or concerns to using DSM to help reduce infrastructure costs that should be addressed as policy issues. These include:

1. Changes in the Approval Process for Infrastructure Targeted DSM

The differences in timeline and risk between DSM achieving annual energy savings and related benefits, and DSM targeted at specific infrastructure investment deferral or avoidance create different planning requirements. Geo-targeted DSM programs designed to reduce peak hour demand will need to be implemented much earlier in the facility planning cycle, often before there is certainty around load growth, and will have limited opportunity for revisions if the programs are not meeting expectations. In addition, the ultimate impacts of the programs – deferral or avoidance of infrastructure investment – will be subject to the general planning uncertainty consistent with the necessary implementation time frame.

As such, DSM programs and technologies targeted at infrastructure deferral or avoidance may need to be subject to a different business and regulatory construct, cost benefit analysis and different evaluation standards than standard DSM.

2. Allocation of Risk

While the Gas Utilities are planning pilot studies and reviewing additional analyses, the Gas Utilities currently face uncertainty regarding the reliability of DSM programs designed to reduce peak demand. As a result, there is an increase in risk and an increase in cost to the utility of relying on DSM programs as an alternative to infrastructure investment. This leads to a number of public policy questions:

- How much risk is appropriate? And how should the risk of underestimating facilities requirements be weighted relative to the risk of overestimating facilities requirements? Is the risk to society of potentially not having the necessary energy services in place an acceptable risk? How would this risk be assessed?
- In order to provide reasonable assurance that the system will be available to meet demand, the Gas Utilities likely will need to develop plans for both geo-targeted DSM programs and the facilities investments needed to meet demand if the DSM program is not successful. Alternatively, the DSM program will need to be oversized to minimize risk. In both cases, the Gas Utilities expect to incur additional costs that do not directly serve to meet system requirements. How do the Gas Utilities recover these additional costs?
- Who bears the risk if a geo-targeted DSM program does not lead to a deferral of an infrastructure investment? In this scenario, the utility would have invested in geo-targeted DSM activities without reducing facilities investment.
- Who bears the risk if the benefits of a geo-targeted DSM program do not materialize, and the utility pipeline system is insufficient to meet peak demand?

3. Additional Research

Incorporation of DSM to reduce infrastructure investments as part of the normal infrastructure planning process will require additional certainty regarding the costs of geo-targeted DSM programs, and the impact of DSM programs on peak period demand, which will require additional data collection and research. The Gas Utilities will need regulatory approval to invest in, and recover the costs of the Advanced Metering Infrastructure (AMI) necessary to collect hourly data on the impacts of DSM programs and measures, as well as pilot programs necessary to determine the costs, impacts, and potential penetration rates for geo-targeted DSM programs.

4. Cross-Subsidization

In the current 'postage stamp' rate setting framework, the costs of new infrastructure are shared across customer classes, where all customers within a rate class pay the same amount throughout the franchise, except in specific cases where the Board has determined that a specific customer contribution is required for a particular new infrastructure. Geo-targeted DSM programs have the potential to lead to cross-subsidization between customer classes, and between DSM participants and other customers.

5. Customer Discrimination

By definition, the use of geo-targeted DSM programs to reduce infrastructure investments will lead to discrimination between customers at the boundary of the geo-targeted region. Customers within the boundary will be eligible for potentially significant incentives, while customers outside of the boundary will not. This leads to policy questions that will need to be addressed:

- Is it appropriate to subsidize customer energy efficiency based on location, potentially providing incentives to customer on one side of the street, while denying these incentives to customers on the other side of the street, or in other nearby locations?
- Is it appropriate to provide energy efficiency subsidies to some new communities?

A geo-targeted DSM program designed to impact peak hour requirements may also result in differences in incentives available based on customer characteristics, leading to additional customer discrimination.

- Customers in smaller homes are less likely to be creating significant new gas loads, hence are less likely to be effective targets for geo-targeted DSM. This could result in a high proportion of the incentive payments being paid to customers that are generating the increased peak load.
- As a result, the overall costs of geo-targeted DSM may be inappropriately distributed to those customers who are in older, smaller, less efficient homes.

6. Incentives for Non-General Services Customers

Achieving the DSM market penetration necessary to defer investments in new facilities is likely to take several years of targeted DSM activity. Given the relative timeframes for DSM program implementation, geo-targeted DSM programs designed to reduce infrastructure costs for projects targeting new communities may need to target consumers that are not currently utility customers in order to reduce future demand by sufficient amount to achieve the program's objectives. This would not be allowed under the current DSM Framework. Is it appropriate to provide subsidies to consumers that are not currently customers of the utility, with the expectation that they might become customers in the future?

In addition, the need for much of the utility infrastructure investment, particularly on the Union system, is driven by the growth in Firm Transportation (FT) demand by large industrial customers. These customers contract for a specific level of pipeline capacity. However, in the Gas Utilities' experience, when these customers participate in DSM programs, they typically do not reduce the amount of FT capacity that they hold. Instead, they hold on to the capacity to make sure that they have access to the capacity in the future if their requirements increase, or use the capacity to meet new loads.

Hence a geo-targeted DSM program aimed at these customers might not have any impact on facilities requirements unless the program provides a sufficient incentive to the customer for the customer to release the (FT) capacity. This is likely to require different types of incentives and larger incentives than currently offered by the Gas Utilities, and would also require contracting terms that would discourage these customers from requesting additional capacity in the future.

7. Establishment of an Appropriate Leave-to-Construct (LTC) Budget Threshold for Geo-Targeted DSM Programs

Current guidance from the Board suggests that energy efficiency programs should be considered during the planning for each facility project brought before the Board as part of a Leave-to-Construct (LTC) application. The threshold for these LTC projects is currently $2 million, and as further outlined in the OEB Act 1998, part VI, Sect 90. However, developing, implementing, modelling and evaluating geo-targeted DSM programs as an alternative to a specific infrastructure project is expected to be both time consuming and require significant internal resources to perform the modelling, conduct the analysis, and investigate alternatives. Hence considering DSM as an alternative to infrastructure investments is likely to only impact those infrastructure projects with significant savings potential.

Once the initial study of the potential for DSM to reduce infrastructure investment is completed, and the Gas Utilities can provide the Board with a reasonable assessment of the costs and potential benefits, the Gas Utilities will provide a recommendation to the Board on the appropriate cost threshold and which facilities projects should be accompanied by a comprehensive assessment of the potential to reduce the project.

8. Appropriate Cost Effectiveness Test(s)

Geo-targeted 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 (Traditional DSM) and on their ability to reduce infrastructure investment based on the impact on peak hour/peak day demand (traditional facilities planning).

The Gas Utilities consider a combined approach to cost effectiveness testing to be appropriate for geo-targeted DSM programs. Benefits should include the direct cost savings associated with the reduced infrastructure plus the annual energy savings associated with the program. Costs should consider both the ratepayer and societal costs of developing and implementing the targeted DSM programs. The cost-effectiveness criteria also needs to address the increase in risk associated with geo-targeted DSM programs. Ultimately the cost of the resource to the consumer should be a consideration in the various planning processes, with the affordability of energy supply a factor in the decision making process, and whether or not other resources are a viable alternative. If the deferral of a geo-targeted infrastructure project would result in fuel switching to a more expensive energy source this should be recognized and the additional costs to the end use consumer fully valued.

8. Conclusions and Recommendations

To the best of ICF's knowledge, the ICF Integrated Resource Planning study conducted for the Gas Utilities provides the first comprehensive assessment of the potential to use broad-based and geo-targeted DSM as part of the natural gas distribution company facilities planning process in order to reduce investments in new natural gas utility infrastructure. The study includes a review of industry experience, an overview of the facilities planning process, an assessment of the potential impact of DSM programs on peak period demand, and the potential to use DSM to avoid or defer new investments in utility infrastructure, and a review of the policy changes that would facilitate the incorporation of DSM into the facilities planning process. The primary conclusions of the study are developed based on the findings discussed earlier in this Executive Summary, and are summarized below.

8.1 Critical Elements of the Facilities Planning Process

Section 3 of this Executive Summary provides an overview of the facilities planning process. However, there are a few basic facilities planning principles that impact the potential for DSM programs to reduce infrastructure investments that need to be highlighted due to their importance. These include:

1) ***The primarily goal of facilities planning is to ensure that the utility infrastructure is of sufficient size and at the appropriate/required time to provide reliable natural gas service during peak demand periods*[14] *at system design conditions consistent with reasonable costs.*** Failure to meet peak period demands could result in loss of gas supply to firm utility customers during extreme cold conditions, leading to extreme social and economic costs to the utilities and their customers. As a result, the Gas Utilities and their customers have significant economic and social incentives to develop infrastructure based on upside uncertainty in the forecast rather than downside uncertainty.
2) ***The facilities planning process requires significant lead time in order to ensure that facilities are available by the time that the facilities are required***. The facilities planning process is designed to identify expected requirements at about five years prior to the time at which the capacity will be needed in order to allow sufficient time for the project planning

[14] The peak demand period for facilities planning used in our analysis is the peak hour, which typically occurs during the morning period between 7:00 AM and 9:00 AM. For planning purposes, the peak period demand is projected based on design day weather conditions, which typically occur on the coldest anticipated winter day, or design day. The duration of the peak period considered in the planning process depends on the type of infrastructure being evaluated. For individual service connections, the peak period used to size the service connection should be sufficient to meet the maximum customer demand. For certain distribution infrastructure projects serving a limited number of customers, the peak period used for facilities planning may need to be as short as 15 to 30 minutes, while larger transmission assets may be planned based on a longer time frame, potentially a 24 hour design day.

and design, regulatory review, and construction to be completed prior to the need for the facility.

3) ***There are significant economies of scale associated with the construction of facility investment projects.*** The cost of the incremental unit of capacity declines as the size of the project increases due to efficiency in planning, right-of-way and easement availability, mobilization costs, and labor and materials costs. As a result, downsizing a specific project is likely to lead to only modest cost savings. In addition, if a project proves to be undersized relative to future system growth, additional facility investment projects are likely to be much more expensive than increasing the size of the initial project.

4) ***Facilities costs vary widely depending on specific circumstances:*** The ability to cost effectively reduce infrastructure investments through the use of targeted DSM programs depends on the cost of the infrastructure that can be avoided, which vary significantly based on the size of the project, the characteristics of the existing system, and the areas impacted by the project. As a result, the cost effectiveness of DSM programs as an alternative to infrastructure investments can differ widely for different infrastructure projects.

8.2 Summary of Industry Experience using DSM to Reduce Infrastructure Investments

ICF's review of existing DSM programs at North American gas utilities in other jurisdictions, documented in Section 2 of this Executive Summary, found that little to no activity has been undertaken that was designed to reduce transmission and distribution costs using targeted DSM and Demand Response (DR). In addition, measured data necessary to determine the potential impacts of DSM on new facilities requirements is generally unavailable. Overall, the review of industry experience found that:

1) The natural gas industry has extremely limited experience integrating DSM into the facilities planning process, and in using targeted DSM to reduce investments in infrastructure projects. ICF's review of existing DSM programs at North American gas utilities in other jurisdictions found that no activity has been undertaken that was designed to deferred transmission and distribution costs using targeted DSM and DR.

- ICF did not identify any natural gas utilities outside of Ontario that actively consider the impact of DSM programs on peak hour or peak day demand forecasts used for facilities planning. Since this study was initiated in October of 2016, a few gas utilities have begun to consider these impacts. However, these efforts remain in the very early stages.
- Gas utilities in other jurisdictions have expressed concerns about the reliability of the DSM impacts as an infrastructure investment alternative due to the lack of information on the measured impacts of DSM on peak hourly demand.[15]

2) ICF also assessed activity in the electric power industry. While some progress has been made in the electric power industry to defer transmission and distribution costs using

[15] Note that, to date, no natural gas utilities have actually measured the impact of DSM programs on peak period demand.

targeted energy efficiency, differences in utility cost structure, duration of peak period requirements, and availability of data on DSM impacts leads ICF to the conclusion that geo-targeted DSM programs are likely to be more cost-effective for the electric industry than they are for the natural gas industry, and that the electric industry experience provides only relatively limited value as an example for the gas industry.

The differences between the electric system and the natural gas system include:

- The electric industry can achieve greater infrastructure cost savings from similar DSM and DR measures, due to the higher cost infrastructure of the industry.
- The difference in risk tolerance between the industries, for capacity shortage, also increases the attractiveness of DSM and DR for infrastructure deferral and avoidance in the electric industry relative to the natural gas industry.
- In addition, the ability to accurately measure the impact of DSM due to the advanced metering capabilities of electric utilities reduces risk associated with the reliance on DSM to displace electricity infrastructure. The lack of metered customer data makes estimating peak hour demand impacts difficult for gas utilities and increases facility planning risks.

8.3 Potential for Targeted DSM to Impact Infrastructure Investment

Due to the lack of industry experience, and the lack of measured data on DSM peak period load impacts, ICF conducted most of the research into the potential for DSM to impact infrastructure requirements by extrapolating existing data on DSM program impacts from annual data to peak hourly period data based on building modeling, and other theoretical analysis. While we view the analysis as robust, there remains significant uncertainty, particularly on the cost and reliability of using DSM to reduce infrastructure investment. Hence, our conclusions should be treated as preliminary until additional research is completed.

The assessment of the potential for DSM to impact infrastructure investments is reviewed in Sections 5 and 6 of this Executive Summary. The primary conclusions from ICF's study related to the potential impacts of DSM measures and programs are summarized below:

1) ***DSM can impact peak hour natural gas demand and natural gas demand growth.*** While there is little to no measured data on actual peak hour impacts of natural gas DSM programs, ICF's analysis indicates that many, but not all, DSM measures should be expected to have measurable impacts on peak hour natural gas demand:

    - In general, industrial measures are most cost-effective at reducing peak hour demand, followed by commercial sector measures, and then residential sector measures.
    - Space heating is important from a winter peak hourly demand perspective, even in the industrial sector. Measures that result in space heating savings, such as air sealing, insulation, central heating systems and boiler measures, contribute disproportionately to winter peak hour savings.
    - Adaptive thermostats lead to annual gas consumption savings but initial analysis shows that this measure may increase winter peak hour demand since HVAC systems are recovering from temperature setback during this period.

  - Residential building modeling indicates that adaptive thermostats lead to a significant increase in winter peak hour demand.
  - Commercial building modeling suggest that adaptive thermostats lead to increases in winter peak hour demand in the commercial sector as well but the impact is much smaller than the residential sector due to the lower applicability of this measure in the commercial sector and the diversity of operating schedules in the different types of commercial facilities being considered.
  - During the winter peak day, adaptive thermostats lead to increased demand during other non-setback hours as well since it can take several hours to heat up a building's entire thermal mass.
- At least a portion of the demand impacts from other measures with a controls component may not be coincident with winter peak hourly demand.
- Modeling of tankless water heaters suggests that they can increase peak demand for an individual customer during the relatively short periods that they are in use. However, when impacts are considered on an hourly basis and aggregated across many customers within a community (i.e. such that the diversity of water usage profiles are considered), tankless water heaters are expected to lead to peak demand reductions.
- Based on the building modeling conducted by ICF, DSM is not expected to shift the timing of the hourly peak demand.

2) ***Based on ICF's initial assessment of the potential to reduce peak hour demand using DSM, it appears possible that some infrastructure investments may be reduced through the use of targeted DSM.***
   - ICF's analysis suggests that geo-targeted DSM programs would have the potential to offset demand growth by up to about 1.2 percent per year, before consideration of DSM program and measure costs.
   - ICF's analysis suggests that DSM may be able to cost-effectively defer infrastructure investments in certain situations where annual peak hour demand growth is relatively low and project costs per unit of demand are relatively high.

3) ***Based on ICF's initial assessment of the likely costs of reducing peak hour demand using DSM, the number of infrastructure projects that appear likely to be cost-effectively reduced by targeted DSM is expected to be limited.***
   - Opportunities to reduce facilities investments in a cost-effective manner through the use of geo-targeted DSM are likely to be limited due to the cost of geo- targeted DSM programs relative to the cost of many infrastructure projects.
   - The maximum penetration rate of DSM programs appears likely to be lower than the rate of growth in areas where a significant share of new infrastructure projects are indicated. As a result, DSM programs targeted at infrastructure projects in these regions are more likely to be able to delay a specific project than to eliminate the need for the infrastructure project altogether. The cost effectiveness of geo-targeted DSM programs decreases as the delay in project implementation becomes shorter.

- There is likely a minimum size for facilities investments where geo-targeted DSM programs could be cost-effectively implemented due to DSM program development, implementation, and monitoring costs.

8.4 Policy and Planning Changes Needed to Facilitate Use of Targeted DSM to Impact Infrastructure Investment

Facilities planning and DSM planning processes are currently independent of each other, and operate under different regulatory structures. Given the range of differences between the existing planning process, and the needs and objectives of the facilities planning process, it is likely that implementation of geo-targeted DSM will require a specific planning and regulatory framework, determined for the express purpose of deferring natural gas infrastructure.

Integrating the potential for DSM to reduce infrastructure requirements into the facilities planning process will require significant changes in policy, as well as changes in the utility planning process. These issues are explored in more depth in Section 4 (Utility Planning) and Section 7 (Policy) of this Executive Summary. The primary conclusions include:

1) ***ICF's review indicates that changes in Ontario energy policy and utility regulatory structure would be necessary to facilitate the use of DSM to reduce infrastructure investments.*** These changes would include:
   - 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 Advanced Metering Infrastructure (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 frame associated with facilities planning.
   - Clarification on the allocation of risk associated with DSM programs that might or might not successfully reduce facilities investments.
   - Guidance on cross subsidization and customer discriminations inherent in geo-targeted 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 improve energy efficiency.
   - Guidance on how to treat uncertainty associated with energy efficiency programs outside the control of the Utilities that impact peak period demand.
2) ***There are a number of differences between the DSM and facilities planning process that must be reconciled in order to factor in geo-targeted DSM to reduce facilities investments.***
   - This includes differences in risk and reliability criteria, cost-effectiveness criteria, program assessment and planning timeframes.

- The linkages between DSM planning and facilities planning are currently 'passive' rather than 'active', and are not sufficient to actively integrate geo-targeted DSM programs into the facilities planning process.
- Underestimating facilities requirements can lead to significant operational problems for the gas utility (such as widespread customer outages during cold weather), leading to a very risk adverse planning process for facilities investments. Given the lack of data on actual impacts of DSM measures on peak hour demand, DSM is generally considered a high risk alternative to facility investments that would be inconsistent with facilities planning criteria.

3) ***Differences in the risk profile between facilities planning and DSM planning create significant challenges in incorporating DSM programs into the facilities planning process.*** Underestimating facilities requirements can lead to significant operational problems for the gas utility, leading to a very risk adverse planning process for facilities investments. Given the lack of data on actual impacts of DSM measures on peak hour demand, DSM is generally considered a high risk alternative to facility investments that would be inconsistent with facilities planning criteria.

8.5 Recommendations for Additional Research

The use of DSM to reduce investments in natural gas facilities remains relatively untried and untested. While ICF has identified areas where there is potential to use DSM to avoid infrastructure investments, there remains significant uncertainty in both the potential and the cost of achieving that potential. There is little to no actual measured data on DSM program impacts on peak period demand for natural gas, and there are no significant real world examples that ICF can point at to indicate that DSM can be used effectively for this purpose.

As a result, there is currently a fundamental disconnect between the limited risk acceptable to the Utilities in the facilities planning process and the lack of information on the ability of DSM to reliably reduce peak period demand that will need to be addressed before the Utilities would be able to rely on DSM to reduce infrastructure investment as part of the normal business planning process:

- The lack of real measured data creates significant uncertainty in the evaluation of the potential to use DSM to reduce infrastructure investments and increases the risk (hence the cost) of using DSM to reduce infrastructure investments.
- The lack of reliable program implementation cost data for geo-targeted DSM programs makes accurate cost comparisons between facilities and DSM unavailable.

Hence, one of the most important conclusions from this study is that ***additional research is necessary before the Gas Utilities would be able to rely on DSM to reduce new infrastructure investments as part of the standard utility facilities planning process***. This research needs to include:

- ***Collection of hourly demand data:*** Collection and evaluation of measured hourly demand data needed to more accurately assess the impact of DSM measures and programs on peak period demand is needed to determine the cost and implementation potential of DSM measures and programs before the Gas Utilities would be able to rely on DSM to reduce new infrastructure investments as part of the standard facilities planning process. This will require installation of Advanced Meter infrastructure installation (AMI), and automated meter reading (AMR) capability. Until actual hourly data is available, the Gas Utilities will not be in a position to accurately determine the potential cost-effectiveness of using DSM as an alternative to infrastructure investments.

- **Assessment of the reliability of using targeted DSM to reduce peak hour demand growth:** The risk associated with relying on DSM to reduce peak hour demand is one of the major stumbling blocks in using DSM to reduce infrastructure investments. ICF expects that development of specific pilot studies that test the ability of the utility to offset demand growth using DSM pilot programs will be the best approach to resolving these reliability issues.
- ***Assessment of the cost of geo-targeted DSM implementation*****:** The cost per participant of implementing geo-targeted DSM programs is expected to be significantly higher than the costs of implementing system-wide DSM programs. The additional costs are based on the smaller program scale associated with geo-targeted DSM programs, the tailored nature of targeted DSM programs, and the need for additional monitoring and evaluation. Based on available information, and on our experience with DSM program implementation, these costs are estimated at 2-4 times higher than typical DSM program costs. However, until actual pilot studies are developed and implemented, the actual increase in costs will be unknown. The magnitude of these costs may determine whether or not geo-targeted DSM programs can be cost-effective.

PROPOSED 2018 DSM SCORECARDS

RESOURCE ACQUISITION SCORECARD

Union Gas 2018 Resource Acquisition Scorecard

Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
Home Reno Rebate; Commercial/Industrial Prescriptive; Commercial/Industrial Custom; Commercial/Industrial Direct Install.	Cumulative Natural Gas Savings (m^3)	75% of Target	2017 metric achievement ÷ 2017 actual offering spend without overheads × 2018 offering budget without overheads × 1.02	150% of Target	75%
Home Reno Rebate	Home Reno Rebate Participants (Homes)	75% of Target	2017 metric achievement ÷ 2017 actual offering spend without overheads × 2018 offering budget without overheads × 1.02	150% of Target	25%

LOW INCOME SCORECARD

Union Gas 2018 Low Income Scorecard

Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
Home Weatherization; Furnace End-of-Life Upgrade; Indigenous.	Single-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2017 metric achievement ÷ 2017 actual offering spend without overheads × 2018 offering budget without overheads × 1.02	150% of Target	60%
Multi-Family	Multi-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2017 metric achievement ÷ 2017 actual offering spend without overheads × 2018 offering budget without overheads × 1.02	150% of Target	40%

LARGE VOLUME SCORECARD

Union Gas 2018 Large Volume Scorecard						
Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
Large Volume Direct Access	Cumulative Natural Gas Savings (m^3)	75% of Target	Three-year rolling average (2015-2017) offering cost effectiveness × 2018 offering budget without overheads × 1.02	150% of Target	100%

MARKET TRANSFORMATION SCORECARD

Union Gas 2018 Market Transformation Scorecard					
Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
Optimum Home	Participating Builders (Regional Top 10)[1]	6	8	12	10%
	Prototype Homes Built[2]	45%	60%	90%	30%
	Homes Built (>15% above OBC 2017) by Participating Builders[3]	3.75%	5%	7.5%	10%

[1] Incremental builders enrolled in the program year for the 15% greater than OBC 2017 program cycle. Eligible builders are the top 10 builders in each region based on number of housing starts in Union's franchise area in prior calendar year. The seven regions are: Halton, Hamilton, London, Waterloo, Windsor, Kingston and North.

[2] Percentage of participating builders who have constructed a prototype home at least 15% greater than OBC 2017, based on the total number of builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the number of participating builders who have constructed a prototype home which has been certified to at least a 15% higher energy efficiency standard than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of builders who remain enrolled in the program.

[3] Calculated as the percentage of homes built to a 15% higher energy efficiency standard than OBC 2017 in relation to the total number of homes built in a program year by participating builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the total number of residential homes constructed by participating builders certified to at least 15% greater than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of residential homes constructed between January 1 and December 31 of the program year as per the Union Gas customer attachment report by participating builders who remain enrolled in the program. This report includes all residential homes listed by builder who requested the service. Homes are included in the report when their Union Gas account is activated.

Commercial Savings by Design	New Developments Enrolled by Participating Builders	75% of Target	2017 metric achievement ÷ 2017 actual offering spend without overheads × 2018 offering budget without overheads × 1.1	150% of Target	50%

PERFORMANCE-BASED SCORECARDS

Union Gas 2018 Performance-Based Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
RunSmart	Participants	75% of Target	2017 Actual Achievement × 1.1	150% of Target	10%
	Savings (%)	75% of Target	2017 Actual Achievement × 1.1	150% of Target	40%
Strategic Energy Management	Participants	75% of Target	2017 Actual Achievement × 1.1	150% of Target	10%
	Savings (%)	4%	5%	8%	40%

PROPOSED 2019-2020 DSM SCORECARDS

RESOURCE ACQUISITION SCORECARDS

Union Gas 2019 Resource Acquisition Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Home Reno Rebate; Commercial/Industrial Prescriptive; Commercial/Industrial Custom; Commercial/Industrial Direct Install.	Cumulative Natural Gas Savings (m^3)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	75%
Home Reno Rebate	Home Reno Rebate Participants (Homes)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	25%

Union Gas 2020 Resource Acquisition Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Home Reno Rebate; Commercial/Industrial Prescriptive; Commercial/Industrial Custom; Commercial/Industrial Direct Install.	Cumulative Natural Gas Savings (m^3)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	75%
Home Reno Rebate	Home Reno Rebate Participants (Homes)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	25%

Upon OEB approval of Union's proposed Residential Adaptive Thermostat offering within the Residential program, as per Section 1 of this submission, an additional 34,645,000 m^3 will be added to the Cumulative Natural Gas Savings (m^3) metric target for the 2019 scorecard, to account for the new offering and incremental budget. Furthermore, the *"2019 offering budget without overheads"* figure within the target adjustment mechanism will not include the incremental Residential Adaptive Thermostat offering budget. Specifically, the target adjustment mechanism for the Cumulative Natural Gas Savings (m^3) metric for the 2019 scorecard will be:

2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads (not including the Residential Adaptive Thermostat offering) × 1.02 + 34,645,000 m^3

The target adjustment mechanism for the Cumulative Natural Gas Savings (m^3) metric on the 2020 scorecard will remain unchanged, and will include the results and spend from the 2019 Residential Adaptive Thermostat offering, and the budget for the 2020 Residential Adaptive Thermostat offering.

Low Income Scorecards

Union Gas 2019 Low Income Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Home Weatherization; Furnace End-of-Life Upgrade; Indigenous.	Single-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	60%
Multi-Family	Multi-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.02	150% of Target	40%

Union Gas 2020 Low Income Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Home Weatherization; Furnace End-of-Life Upgrade; Indigenous.	Single-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	60%
Multi-Family	Multi-Family Cumulative Natural Gas Savings (m^3)	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.02	150% of Target	40%

LARGE VOLUME SCORECARDS

Union Gas 2019 Large Volume Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Large Volume Direct Access	Cumulative Natural Gas Savings (m^3)	75% of Target	Three-year rolling average (2016-2018) offering cost effectiveness × 2019 offering budget without overheads × 1.02	150% of Target	100%

Union Gas 2020 Large Volume Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Large Volume Direct Access	Cumulative Natural Gas Savings (m^3)	75% of Target	Three-year rolling average (2017-2019) offering cost effectiveness × 2020 offering budget without overheads × 1.02	150% of Target	100%

Market Transformation Scorecards

Union Gas 2019 Market Transformation Scorecard

Offering(s)	Metric	Metric Targets			Weight
		Lower Band	Target	Upper Band	
Optimum Home	Participating Builders (Regional Top 10) [1]	3	4	6	10%
	Prototype Home Built[2]	67.5%	90%	100%	10%
	Homes Built (>15% above OBC 2017) by Participating Builders[3]	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.1	150% of Target[4]	30%
Commercial Savings by Design	New Developments Enrolled by Participating Builders	75% of Target	2018 metric achievement ÷ 2018 actual offering spend without overheads × 2019 offering budget without overheads × 1.1	150% of Target	50%

[1] Incremental builders enrolled in the program year for the 15% greater than OBC 2017 program cycle. Eligible builders are the top 10 builders in each region based on number of housing starts in Union's franchise area in prior calendar year. The seven regions are: Halton, Hamilton, London, Waterloo, Windsor, Kingston and North.

[2] Percentage of participating builders who have constructed a prototype home at least 15% greater than OBC 2017, based on the total number of builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the number of participating builders who have constructed a prototype home which has been certified to at least a 15% higher energy efficiency standard than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of builders who remain enrolled in the program.

[3] Calculated as the percentage of homes built to a 15% higher energy efficiency standard than OBC 2017 in relation to the total number of homes built in a program year by participating builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the total number of residential homes constructed by participating builders certified to at least 15% greater than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of residential homes constructed between January 1 and December 31 of the program year as per the Union Gas customer attachment report by participating builders who remain enrolled in the program. This report includes all residential homes listed by builder who requested the service. Homes are included in the report when their Union Gas account is activated.

[4] Upper Band figure capped at 100%.

Union Gas 2020 Market Transformation Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
Optimum Home	Homes Built (>15% above OBC 2017) by Participating Builders[5]	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.1	150% of Target[6]	50%
Commercial Savings by Design	New Developments Enrolled by Participating Builders	75% of Target	2019 metric achievement ÷ 2019 actual offering spend without overheads × 2020 offering budget without overheads × 1.1	150% of Target	50%

Performance-Based Scorecards

Union Gas 2019 Performance-Based Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
RunSmart	Participants	75% of Target	2018 Actual Achievement × 1.1	150% of Target	10%
	Savings (%)	75% of Target	2018 Actual Achievement × 1.1	150% of Target	40%
Strategic Energy Management	Savings (%)	75% of Target	2018 Actual Achievement × 1.1	150% of Target	50%

[5] Calculated as the percentage of homes built to a 15% higher energy efficiency standard than OBC 2017 in relation to the total number of homes built in a program year by participating builders who remain enrolled in the program at the end of the program year. The numerator in the calculation is the total number of residential homes constructed by participating builders certified to at least 15% greater than OBC 2017 between January 1 and December 31 of the program year. The denominator in the calculation is the total number of residential homes constructed between January 1 and December 31 of the program year as per the Union Gas customer attachment report by participating builders who remain enrolled in the program. This report includes all residential homes listed by builder who requested the service. Homes are included in the report when their Union Gas account is activated.

[6] Upper Band figure capped at 100%.

Union Gas 2020 Performance-Based Scorecard					
Offering(s)	**Metric**	**Metric Targets**			**Weight**
		Lower Band	**Target**	**Upper Band**	
RunSmart	Participants	75% of Target	2019 Actual Achievement × 1.1	150% of Target	10%
	Savings (%)	75% of Target	2019 Actual Achievement × 1.1	150% of Target	40%
Strategic Energy Management	Savings (%)	75% of Target	2019 Actual Achievement × 1.1	150% of Target	50%

SUMMARY OF UNION'S REQUESTS FOR OEB APPROVAL

Item	Submission	Reference
Modification of Net-to-Gross adjustment methodology	Part One	pp. 9-13
Modification of shareholder incentive mechanism	Part One	pp. 16-20
Modification of 2018 targets or budgets	Part One	pp. 16-20
Energy Literacy program	Part Two Requirement One	pp. 16-19
Residential Adaptive Thermostat offering	Part Two Requirement Two	pp. 4-6
2018 DSM Scorecards	Part Two Requirement Two	pp. 16-23 and Appendix D
2019-2020 DSM scorecards	Part Two Requirement Two	pp. 30-48 and Appendix E
DSM budget and shareholder incentive reallocation procedure	Part Two Requirement Two	pp. 49-50