Enbridge Gas 2023-2027 Demand Side Management Application Hearing Compendium

EB-2021-0002

March 31, 2022 - REVISED

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Menu

2021-2024 Conservation and Demand Management Framework

September 30, 2020

WHEREAS the Government remains committed to ensuring that Ontario has an affordable and reliable electricity system, while continuing to find efficiencies in the electricity sector;

AND WHEREAS it is desirable that the Independent Electricity System Operator (IESO) establish a new four-year electricity conservation and demand management (CDM) framework aimed at offering a suite of centrally-delivered CDM programs to help consumers, including commercial, industrial, institutional and on-reserve First Nations consumers, as well as low-income and income-eligible residential consumers, manage their electricity use while meeting electricity system needs;

AND WHEREAS the Minister of Energy, Northern Development and Mines may, with the approval of the Lieutenant Governor in Council, issue directives under subsection 25.32(5) of the *Electricity Act, 1998* that require the IESO to undertake any initiative or activity that relates to measures related to the conservation of electricity or the management of electricity demand;

NOW THEREFORE the Directive attached hereto is approved.

Background

In March 2019, our government directed the IESO to immediately discontinue the 2015-2020 Conservation First Framework and replace it with a 2019-2020 Interim Framework that streamlined and centralized program delivery. Under the Interim Framework, electricity CDM programs were refocused to those who need them most, including low-income households, First Nations communities, as well as commercial, institutional and industrial consumers.

The outbreak of the Novel Coronavirus (COVID-19) in Ontario in early 2020 has had a significant impact on electricity consumers, the electricity system and Ontario's economy. Our government recognizes that electricity CDM programs help consumers manage their energy costs, help cost-effectively meet system needs and are an important contributor to Ontario's economy.

Our government is now introducing a new four-year electricity CDM procurement initiative (COM Framework) that would apply immediately after the term of the current Interim Framework ends, launching on January 1, 2021.

As Ontario recovers from the COVID-19 pandemic, the 2021-2024 CDM Framework will provide continued opportunities for electricity consumers to manage their electricity costs, provide stability for the network of companies involved in the delivery of CDM programs in the province and help to cost-effectively meet electricity system needs.

Overview of CDM Programs

The new CDM Framework will focus on cost-effectively meeting the needs of Ontario's electricity system, including by focusing on the achievement of provincial peak demand reductions, as well as targeted approaches to address regional and/or local electricity system needs. Recognizing limited forecasted needs in the CDM Framework's first two years, programs will be designed to maintain program delivery capacity in the province and meet consumer needs, while enabling a ramp up of program offerings in 2023. Through a mid-term review, electricity system needs will be reassessed and consideration will be given to the need for changes to the programs, targets and budgets of the CDM Framework.

The new CDM Framework will leverage competitive procurements and calls for proposals in order to increase competition, improve cost-effectiveness and solicit consumer-based solutions.

Programs under the new CDM Framework will continue to be targeted to those who need them the most, including commercial, industrial, institutional and on-reserve First Nations consumers, as well as low-income and income-eligible consumers.

CDM programs for commercial, industrial and institutional consumers will continue to support business competitiveness and the province's economic recovery, helping businesses improve their productivity and manage costs.

Residential and other consumers will be provided with tools and guidance to help improve their energy efficiency, as well as any regional and/or local programs that may be brought forward through competitive mechanisms.

Overview of Programs for Low-Income and Income Eligible Consumers and First Nations Communities

The government is also renewing programming for low-income and income-eligible consumers and on-reserve First Nations communities across Ontario.

For low-income and income-eligible consumers, access to energy saving measures will be simplified as a single program will be launched to deliver the benefits of two existing programs, the Affordability Fund Program and the Home Assistance Program, in an effort to reduce confusion and enhance customer experience.

For on-reserve First Nations communities, programs under the Interim Framework that were suspended due to the outbreak of COVI0-19 will be relaunched, to allow time for committed projects to be completed. In mid-2021, the programs may evolve based on additional engagement with Ontario's First Nations communities in an effort to respond to changing community needs, while building on the success of previous programs.

DIRECTIVE

Therefore, in accordance with the authority I have pursuant to subsection 25.32(5) of the Act, I hereby direct the IESO to design, coordinate, deliver, and/or fund the delivery of electricity CDM programs outlined in this Directive in accordance with the following requirements.

REQUIREMENTS

A. Governance

1. The IESO shall be directly responsible to deliver the CDM programs, utilizing procurement contracts in connection with those programs as required.
2. To the degree reasonably practicable, the IESO will coordinate the delivery of the CDM programs with entities delivering natural gas Demand Side Management programs.

B. CDM Programs

1. The CDM programs shall be designed to address province-wide and regional and/or local electricity system needs as identified in bulk, regional or distributor planning processes.
2. The IESO shall centrally deliver CDM programs to the following consumer segments or communities who are connected to the IESO-controlled grid or to a regulated distributor's distribution system that is connected to the IESO-controlled grid:
    a. Commercial, institutional or industrial consumers;
    b. On-reserve First Nations communities, including those communities that are soon to be connected to the IESO-controlled grid or to a regulated distributor's distribution system that is connected to the IESO-controlled grid; and
    c. Low-income and income-eligible residential consumers.

3. The IESO shall procure, through competitive mechanisms , measures to address regional and/or local electricity system needs, including through local CDM programs, projects or pilots.

4. The IESO shall also provide residential and other consumers with a suite of online tools, guidelines and information to build awareness of widely available conservation and demand management measures and provide education on energy efficient practices and behaviours.

5. The IESO shall implement only those CDM programs that demonstrate positive cost-benefit benchmarks when jointly considered as a portfolio in accordance with the IESO's Cost-Effectiveness Guide. For clarity, programs described in sections C and D of this Directive will not be required to meet these cost-benefit benchmarks and shall be excluded from the portfolio of CDM programs required to meet such benchmarks.

C. Energy Affordability Program

1. The IESO shall design, coordinate, deliver and fund an income-tested residential program, which will provide different tiers of support based on income eligibility, with the majority of the support provided to low-income households ("Energy Affordability Program").

2. The Energy Affordability Program shall provide electricity saving measures to participants based on an assessment of needs and projected efficiency gains in the home.

3. Despite the Energy Affordability Program not being required to meet cost-benefit benchmarks, the IESO shall nevertheless ensure that this program is designed and delivered in as cost-effective a manner as is reasonably practicable and in a manner that results in impactful electricity bill savings for those most in need of support.

D. On-reserve First Nations Programs

1. The IESO shall work to complete delivery and funding of projects planned under the following three First Nations programs that the IESO delivered under the procurement initiative known as the Interim Framework that was established under the Minister's Directive issued to the IESO on March 21, 2019, as approved by the Lieutenant Governor in Council pursuant to Order-in-Council No. 379/2019: the First Nations Conservation Program, the Conservation on the Coast Program, and the Remote First Nations Energy Efficiency Pilot Program.

2. As the projects under the three programs described in section D.1 are progressing and concluding, the IESO shall design, coordinate, deliver and fund new First Nations programs based on input received from First Nations communities and the Minister.

3. Despite First Nations programs not being required to meet cost-benefit benchmarks, the IESO shall nevertheless ensure that these programs are designed and delivered in as cost-effective a manner as is reasonably practicable and in a manner that results in impactful electricity bill savings for those most in need of support.

E. Definition of CDM

1. The IESO shall consider CDM to be inclusive of activities aimed at reducing peak electricity demand and/or electricity consumption from the electricity system. Examples of CDM include energy efficiency replacements whereby similar output is achieved with less electricity, and behind-the-meter consumer generation.
2. However, for the purposes of the CDM programs , the IESO shall consider CDM to exclude:
    a. Those measures promoted through a different program or initiative undertaken by the Government of Ontario or the IESO; and
    b. Behind-the-meter consumer generation that uses fossil fuels purchased from or otherwise supplied by a third party as a primary fuel source.

F. Term and Limits of Funding

1. The IESO shall make CDM programs available from January 1, 2021 to December 31, 2024 (Term), and no application to the IESO or to other parties involved in the delivery of the CDM programs shall be accepted or approved after the end of the Term.
2. The IESO shall not exceed a total budget of $692 million for the Term and the budget shall be allocated as follows:
    a. Up to $457 million for CDM programs described in paragraph (a) of section B.2, section B.3 and section B.4;
    b. Up to $43 million for central services costs and payments related to the CDM programs described in paragraph (a) of section B.2, section B.3 and section B.4, which shall be inclusive of costs and payments for marketing, Evaluation, Measure and Verification (EM&V), compliance, capacity building and customer support;
    c. Up to $156 million for the Energy Affordability Program; and
    d. Up to $36 million for programs targeting on-reserve First Nations communities.
3. The IESO shall not re-allocate unspent funds between the budget allocations outlined in section F.2.

G. Program and Target Mid-Term Review

1. The IESO shall submit a report to the Minister no later than December 31, 2022 following the completion of a formal mid-term review of:
   a. The alignment of the demand reduction target, electricity target and the CDM Framework budget with the provincial, regional and/or local electricity system needs as identified by the IESO;
   b. The alignment of the CDM program offerings with consumer needs in Ontario, and a comparison against programs from other jurisdictions;
   c. Lessons learned and recommendations from competitive mechanisms for procuring energy efficiency resources, including results to date of the Energy Efficiency Auction Pilot;
   d. The progress and impact of CDM programs, including for low-income and income-eligible consumers and on-reserve First Nations consumers; and
   e. Recommendations on the remainder of the CDM Framework.

H. CDM Plan; Evaluation and Reporting

1. By December 1, 2020, the IESO will deliver to the Ministry of Energy, Northern Development and Mines (Ministry) a CDM plan (Plan) for the Term, including details of the CDM programs that will be offered, their estimated annual costs and expected peak demand reduction and energy savings results. The expected savings of electricity and the expected demand reductions will constitute the targets for the Term, which will respectively be known as the "electricity target" and "demand reduction target" (collectively, the CDM Targets).
2. The IESO shall evaluate, in such frequency as the IESO considers appropriate, incremental electricity savings and peak demand reductions achieved by the CDM programs based on the IESO's EM&V protocols and requirements.
3. The IESO will report achievements to the Ministry, including:
   a. Quarterly, by each CDM program and in aggregate, including but not limited to: participation, electricity and demand savings, greenhouse gas (GHG) emission reductions, as well as forecasted participation for that year, electricity and demand savings and GHG emission reductions throughout the life of the CDM programs;
   b. Quarterly financial reporting, by each CDM program and in aggregate, including but not limited to: payments disbursed and costs committed in the previous quarter and forecasted disbursements and commitments throughout the life of the CDM programs ;
   c. Quarterly, or as appropriate, additional achievements for programs targeting low-income and income-eligible consumers and on-reserve First Nations

consumers, including:

i. Non-energy benefits, e.g., home safety and comfort;

ii. Province-wide coverage;

iii. Progress towards yearly enrolment targets; and

iv. Participant satisfaction, where feasible;

d. As required, lessons learned, upcoming issues, recommended program changes and proposed timelines for any changes; and

e. As required, or specified by the Ministry from time to time, any other information, as may be required by the Ministry or deemed relevant for reporting by the IESO.

4. The IESO shall continue to produce and publish annual reports detailing the overall progress of the CDM programs from the period of January 1 to December 31 of the previous year.

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2021-2024 Conservation and Demand Management Framework

2021-2024 Conservation and Demand Management Framework Program Plan

The Conservation and Demand Management (CDM) Framework Program Plan is an overview of the CDM programs to be delivered by the IESO, under the Save on Energy brand, from January 2021 to December 2024. The plan sets out forecast budgets and, where applicable, savings targets and estimated cost-effectiveness for the portfolio of CDM programs.

The IESO will report on program participation, expenditures against budget, and progress towards demand and energy savings targets, greenhouse gas emission reductions, and additional achievements of the Energy Affordability Program and on-reserve First Nations programs, on an annual and quarterly basis. In addition, the IESO will undertake a formal review of progress and strategy at the midpoint of the framework in late 2022. This review is to ensure that the CDM program offerings, targets, and budget are effectively meeting both electricity system and customer needs. Findings and recommendations from the midterm review may be used to adjust and enhance the CDM program offerings for the second half of the framework.

2021-2024 CDM Framework Overview

The 2021-2024 CDM Framework focuses on cost-effectively meeting the needs of electricity consumers and Ontario's electricity system through the delivery of programs and opportunities to enable electricity consumers to improve the energy efficiency of their homes, businesses and facilities. As Ontario recovers from potential impacts of the Novel Coronavirus (COVID-19), the IESO and government recognize that electricity CDM programs provide continued opportunities for electricity consumers to save on energy costs and are an important contributor to Ontario's economy. Additional focus areas of the framework include:

- Achieving provincial peak demand reductions and implementing targeted approaches to address regional/local system needs using demand side solutions as cost-effective alternatives to traditional infrastructure investments
- Leveraging competitive mechanisms to drive cost efficiencies and support innovative customer based-solutions

Details about the various incentives offered through each program and how to apply for programs is available at SaveOnEnergy.ca.

Budget and Targets:

The plan, which is subject to changes and revisions over time, allocates the 2021-2024 Conservation and Demand Management Framework budget of up to $692 million over the suite of programs and is forecasted to achieve 440 MW of peak demand savings and 2.7 TWh of electricity savings.

Reporting:

As part of its responsibilities, the IESO will publish the verified results of its Evaluation, Measurement, and Verification (EM&V) of the savings resulting from the 2021-2024 CDM Framework, as well as costs related to its activities in support of programs such as audits, capability building and training. The IESO will publish verified program results on a yearly basis, as well as quarterly program updates, to inform the sector on the progress to meeting the targets.

Cost Effectiveness:

Program cost-effectiveness under the 2021-2024 CDM Framework for the CDM Plan is assessed using forecasted program participation and supply side avoided costs – which estimate the cost of supplying that same amount of energy from the current electricity generation mix. The IESO Cost-Effectiveness Guide is available on the IESO website. Cost effectiveness in this plan is based on avoided supply costs developed in the IESO's January 2020 Annual Planning Outlook and may be updated at mid-term subject to changes in updated annual planning outlooks.

2021-2024 CDM Framework Summary Tables

- *The following tables outline the associated budget, electricity and demand savings, and cost-effectiveness of the programs delivered under the 2021-2024 CDM Framework.*

Budget

Program	Budget ($M)			
	2021	2022	2023	2024
Retrofit Prescriptive Program	57.6	54.5	39.0	39.0
Small Business Program	9.1	9.2	5.1	5.1
Energy Performance Program	4.4	3.5	6.9	7.2
Energy Management	3.5	8.3	14.0	14.0
Customer Solutions	0.0	0.0	55.0	55.0
Local Initiatives	15.4	14.5	18.0	17.7
Total Business Programs	**90.0**	**90.0**	**138.0**	**138.0**
Energy Affordability Program	36.7	37.5	38.9	40.2
First Nations Program	9.0	9.0	9.0	9.0
Total Support Programs	**45.7**	**46.5**	**47.9**	**49.3**
Total all Programs	**135.7**	**136.5**	**185.9**	**187.2**
Customer Education and Tools	0.3	0.3	0.3	0.3
Central Services - Business	9.7	9.7	11.7	11.7
Central Services - Support	0.3	0.8	0.8	0.8
Total IESO Services	**10.3**	**10.8**	**12.8**	**12.8**
Total Annual Budget	**146.0**	**147.3**	**198.7**	**200.1**
CDM Framework Total				**692.0**

Peak Demand and Energy Savings

	Peak Demand Savings (MW)				Energy Savings (GWh)			
Program	**2021**	**2022**	**2023**	**2024**	**2021**	**2022**	**2023**	**2024**
Retrofit Program	57.7	54.5	42.2	42.2	354.3	337.8	217.2	217.2
Small Business Program	5.3	3.9	1.9	2.1	40.2	28.5	14.3	15.3
Energy Performance Program	2.8	2.2	4.3	4.5	21.8	17.3	34.1	35.6
Energy Management	2.1	6.8	16.1	16.1	16.4	47.3	115.2	115.2
Customer Solutions	0.0	0.0	44.1	44.1	0.0	0.0	325.7	325.7
Local Initiatives	13.6	12.5	15.7	15.3	52.4	52.4	62.9	62.9
Total Business Programs	**81.3**	**79.9**	**124.3**	**124.3**	**485.0**	**483.3**	**769.4**	**771.9**
Energy Affordability Program	6.1	6.5	6.7	7.0	47.6	50.3	52.3	54.0
First Nations Program	1.2	0.9	0.9	0.9	10.3	7.3	7.3	7.3
Total Support Programs	**7.3**	**7.4**	**7.6**	**7.9**	**57.9**	**57.7**	**59.6**	**61.5**
Total Annual Savings	**88.6**	**87.3**	**131.9**	**132.2**	**542.9**	**541.0**	**829.0**	**833.4**
CDM Framework Total				**440**				**2746**

Program Cost-Effectiveness

	Cost Effectiveness		
	Program Administrator Cost (PAC) Ratio	**Levelized Unit Energy Costs ($/MWh)**	**Levelized Unit Capacity Costs ($'000/MW-yr)**
Retrofit Prescriptive Program	2.3	19	118
Small Business Program	1.1	39	308
Energy Performance Program	1.5	31	246
Energy Management	1.5	29	208
Customer Solutions	2.2	22	164
Local Initiatives	1.4	37	148
All Business Programs	**1.9**	**25**	**155**

Technical Notes:

- *Peak demand savings are calculated in accordance with the IESO Evaluation, Measurement and Verification Protocols and Requirements which are available on* IESO.ca *Peak demand savings and energy savings are persisting savings in 2026.*
- *Budgets are funds committed in the calendar year; energy and demand savings in a calendar year are those resulting from the budget commitment.*
- *Cost effectiveness is calculated in accordance with the IESO's Cost Effectiveness Guide which is available on* IESO.ca*. Avoided supply costs are based on the IESO's January 2020 Annual Planning Outlook.*
- *As per the* September 30th Ministerial Directive*, the Energy Affordability Program and First Nation Programs are not required to meet cost effectiveness thresholds as these programs provide significant non-energy benefits not captured through cost-effectiveness analysis.*

Government of Canada / Gouvernement du Canada

Heating and Cooling With a Heat Pump

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Introduction

If you are exploring options to heat and cool your home or reduce your energy bills, you might want to consider a heat pump system. Heat pumps are a proven and reliable technology in Canada, capable of providing year-round comfort control for your home by supplying heat in the winter, cooling in the summer, and in some cases, heating hot water for your home.

Heat pumps can be an excellent choice in a variety of applications, and for both new homes and retrofits of existing heating and cooling systems. They are also an option when replacing existing air conditioning systems, as the incremental cost to move from a cooling-only system to a heat pump is often quite low. Given the wealth of different system types and options, it can often be difficult to determine if a heat pump is the right option for your home.

- Time-temperature defrost is started and ended by a pre-set interval timer or a temperature sensor located on the outside coil. The cycle can be initiated every 30, 60 or 90 minutes, depending on the climate and the design of the system.

Unnecessary defrost cycles reduce the seasonal performance of the heat pump. As a result, the demand-frost method is generally more efficient since it starts the defrost cycle only when it is required.

Supplementary Heat Sources

Since air-source heat pumps have a minimum outdoor operating temperature (between -15°C to -25°C) and reduced heating capacity at very cold temperatures, it is important to consider a **supplemental heating source** for air-source heat pump operations. Supplementary heating may also be required when the heat pump is defrosting. Different options are available:

- **All Electric:** In this configuration, heat pump operations are supplemented with electric resistance elements located in the ductwork or with electric baseboards. These resistance elements are less efficient than the heat pump, but their ability to provide heating is independent of outdoor temperature.
- **Hybrid System:** In a hybrid system, the air-source heat pump uses a supplemental system such as a furnace or boiler. This option can be used in new installations, and is also a good option where a heat pump is added to an existing system, for example, when a heat pump is installed as a replacement for a central air-conditioner.

See the final section of this booklet, *Related Equipment*, for more information on systems that use supplementary heating sources. There, you can find discussion of options for how to program your system to transition between heat pump use and supplementary heat source use.

Energy Efficiency Considerations

To support understanding of this section, refer to the earlier section called *An introduction to Heat Pump Efficiency* for an explanation of what HSPFs and SEERs represent.

In Canada, energy efficiency regulations prescribe a minimum seasonal efficiency in heating and cooling that must be achieved for the product to be sold in the Canadian market. In addition to these regulations, your province or territory may have more stringent requirements.

Minimum performance for Canada as a whole, and typical ranges for market-available products, are summarized below for heating and cooling. It is important to also check to see whether any additional regulations are in place in your region before selecting your system.

Cooling Seasonal Performance, SEER:

- Minimum SEER (Canada): 14
- Range, SEER in Market Available Products: 14 to 42

Heating Seasonal Performance, HSPF

- Minimum HSPF (Canada): 7.1 (for Region V)
- Range, HSPF in Market Available Products: 7.1 to 13.2 (for Region V)

Note: HSPF factors are provided for AHRI Climate Zone V, which has a similar climate to Ottawa. Actual seasonal efficiencies may vary depending on your region. A new performance standard that aims to better represent performance of these systems in Canadian regions is currently under development.

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DECISION AND ORDER

EB-2020-0091

ENBRIDGE GAS INC.

Integrated Resource Planning Proposal

BEFORE: Lynne Anderson
Presiding and Chief Commissioner

Susan Frank
Commissioner

Michael Janigan
Commissioner

July 22, 2021

interruptible services, and could potentially file revised interruptible and firm seasonal services/rates to make them more attractive to customers as part of its 2024 rebasing application.

Supply-side Gas IRPAs

Enbridge Gas also noted several supply-side natural gas solutions that could be considered as IRPAs and alternatives to pipeline construction. Injection of compressed natural gas into the pipeline system in a constrained area, or renewable natural gas sourced within the constrained area, could be potential alternatives to pipeline construction/expansion to meet a system need.

No parties objected to the consideration of the supply-side solutions proposed by Enbridge Gas. FRPO submitted that more consideration needed to be given to market-based supply-side alternatives and commercial transactions. FRPO submitted that through appropriate contractual arrangements requiring delivery of natural gas to specific points on Enbridge Gas's system, the capability of existing pipeline infrastructure (including non-Enbridge Gas pipelines including the TCPL mainline) could be harnessed to avoid or defer the need for Enbridge Gas to build new pipeline infrastructure.

Non-Gas IRPAs, including Electricity

Enbridge Gas sought approval to use non-gas alternatives, including electricity-based solutions, as IRPAs, and specifically requested confirmation from the OEB as to whether or not non-gas alternatives can be considered. Potential non-gas alternatives could include electric air source heat pumps, geothermal systems, and district energy systems. Enbridge Gas acknowledged that these would be new activities that go beyond gas distribution.

Enbridge Gas noted that it is permitted to undertake a broad range of activities within the utility corporation, where such activities are related to energy conservation, promotion of cleaner energy sources and ground source heat pumps, through its Undertakings to the Lieutenant Governor in Council, as supplemented by Orders in Council issued by the government of Ontario.

The ability for Enbridge Gas to undertake an activity does not necessarily mean that it is considered a rate-regulated activity, which is based on whether the activity is done as part of the sale of natural gas or the transmission, distribution and storage of gas, which requires an OEB order under s. 36 of the OEB Act. For example, in a decision regarding Enbridge Gas's application for a Renewable Natural Gas Enabling Program, the OEB determined that a proposed Renewable Natural Gas Upgrading service was a permitted activity for Enbridge Gas through its Undertakings, but would not be rate-regulated, as it was not done as part of the sale of gas or the transmission, distribution or storage of gas.[30]

Enbridge Gas submitted that, in the context of IRP, these non-gas activities would be directed at providing an alternative to distribution (or transmission or storage) facilities, and should be considered a rate-regulated activity, similar to the infrastructure being delayed or avoided.

Parties differed as to whether Enbridge Gas should be allowed to pursue non-gas activities. Parties such as ED, GEC, LPMA, and Pollution Probe supported broad consideration of IRPAs. ED and GEC specifically supported electric heat pumps, and ED and OEB staff noted that there was some precedent for Enbridge Gas considering fuel switching measures in the context of demand-side management activities in previous DSM Frameworks.

Parties expressing concerns around an expanded scope of IRPAs including non-gas activities (CME, IGUA, OEB staff, OGVG) generally argued that these activities may fall outside of the OEB's authority to set rates for the sale of gas or the transmission, distribution, and storage of gas under section 36 of the OEB Act. These activities could potentially involve disconnecting existing natural gas customers or avoiding the connection of new natural gas customers. Parties argued that this is not the proper role for a regulated gas distributor, and natural gas customers should not pay the costs to connect customers to electricity. OEB staff submitted that some applications of non-gas IRPAs may fall within the definition of section 36, but that this would likely be limited, and should not encompass providing energy services such as electricity to new customers who would not be connecting to Enbridge Gas's natural gas network.

In reply, Enbridge Gas indicated that if it is not permitted to offer non-gas IRPAs to customers who are not gas distribution customers, then this would greatly limit the ability of IRP efforts to respond to system expansion needs, which, by their nature, involve the connection of new customers. If Enbridge Gas is not able to offer non-gas IRPAs to such customers, Enbridge Gas submitted that it is very likely that IRP will not be a feasible alternative to meet the system expansion need.

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[30] Decision and Order, Application for the Renewable Natural Gas Enabling Program (EB-2017-0319), October 18, 2018, pp. 10-11

GEC and OGVG suggested that, if the OEB determines that it is not appropriate for Enbridge Gas to offer electricity IRPAs, Enbridge Gas should still be required to include non-gas IRPAs in its assessment of alternatives, and, if the electric alternative is determined to be preferable, Enbridge Gas should be required to work with electricity sector entities (e.g. distributors) to facilitate the IRPA. Enbridge Gas submitted that this went beyond the scope of the proceeding, and is not feasible.

OEB staff indicated that the question of whether an alternative energy solution from a provider other than Enbridge Gas, such as an electricity distributor, was preferable could be addressed indirectly, at least for system expansion projects. This would be done by ensuring that any proposed Enbridge Gas system expansion projects were required to pass the E.B.O. 134/188 economic tests (discussed in section 8.3 ("Two-Stage Evaluation Process")), including whether the preferred approach is for Enbridge Gas to take no action. With these tests, system reinforcement costs are accounted for and may result in the requirement for customer contributions. OEB staff suggested that in areas with high system reinforcement costs, these provisions may lead potential customers to choose a different energy supply technology instead of connecting to the natural gas distribution network.

Role of Market Providers in Delivering IRPAs

Parties raised concerns about unfair competition with non-regulated providers, particularly if Enbridge Gas was allowed to offer electricity IRPAs such as geothermal or air source heat pumps, and if it was determined that Enbridge Gas would be allowed to capitalize some costs, and receive a regulated rate of return with an associated revenue requirement. This matter is discussed in chapter 12 (" IRPA Cost Recovery and Accounting Treatment Principles").

Enbridge Gas indicated that, in cases where a demand-side IRPA or an electricity IRPA involves equipment or activities already provided by the competitive market, it would look to this market to assist in providing solutions. For supply-side solutions, Enbridge Gas indicated that its role would depend on the nature of the supply-side solution, but that market-based solutions would be considered.

Short-Term IRPAs

Several parties including FRPO encouraged Enbridge Gas to consider shorter-term solutions to temporarily address a system constraint. Enbridge Gas acknowledged that a "bridging solution" to meet the need on a short-to-medium-term basis might be appropriate. However, Enbridge Gas stressed that a more permanent solution would be needed for the longer term.

Menu/Listing of IRPAs

Several parties, including Energy Probe, FRPO, and OEB staff, indicated that a listing or menu of IRPAs being considered by Enbridge Gas would be useful.

OEB staff suggested that Enbridge Gas should be required to develop and maintain a document on the best available information on IRPAs, filed with Enbridge Gas's annual IRP report. OEB staff suggested that the information provided could include the types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions. OEB staff submitted that this would assist Enbridge Gas and other parties as a starting point for consideration of IRPAs for specific system needs and assist the OEB in its review of Enbridge Gas's consideration of alternatives in Leave to Construct/IRP Plan applications. Enbridge Gas agreed that a proposed record of information on available demand-side IRPAs would be a useful addition to the annual IRP Report; however, Enbridge Gas suggested that supply-side options were too situation-specific to include in the report.

Findings

Enbridge Gas is seeking OEB approval to use a wide variety of demand-side and supply-side IRPAs to meet identified needs/constraints.

Enbridge Gas has considerable experience with implementing demand-side solutions such as energy efficiency programs as part of its DSM Plans; however, the programs and measures in DSM Plans have been focused on reducing overall franchise-wide natural gas use for customers and increasing energy efficiency, rather than directed to targeted peak demand reduction to address system needs.

The OEB agrees that demand-side programming, including geotargeted energy efficiency, and demand response programs, should be part of the IRP Framework. The demand-side IRPAs are expected to target specific constrained areas and (among other objectives) encourage customers to reduce peak consumption. In regard to the December 1, 2020 letter and the relationship between the IRP Framework and DSM Plans, the OEB finds that potential merging of DSM energy efficiency with programs aimed at reducing peak demand to meet system needs is premature. Historically, the programs and measures in DSM Plans have been focused on reducing overall franchise-wide natural gas use for customers and increasing energy efficiency, rather than directed to targeted peak demand reduction to address system needs. The approved IRP Framework will provide opportunities to gain experience on demand-side programming that focuses on reducing peak demand. This experience is needed prior to any effort to merge DSM and IRP programming.

Regarding interruptible rates, ongoing rate design and customer adoption of current rates is part of normal operating process and should not need to be incented through an IRP Plan for Enbridge Gas to make enhancements. The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service. This initiative is expected to help reduce peak demand, and the study should be filed as part of the next rate rebasing application. While approval of interruptible rates would be considered in a rebasing rate application, the impact of interruptible rates to meet a system need/constraint should be considered in an IRP Plan in combination with demand-side or supply-side alternatives.

Supply-side IRPAs, including market-based supply side alternatives, should also be considered, as should natural gas storage.

The OEB finds all of the above options appropriate to the extent that they are cost-effective, and risk has been evaluated and appropriately mitigated. For both demand side and supply-side IRPAs, the OEB supports Enbridge Gas procuring equipment or activities through the competitive market, where feasible and cost-effective. The OEB has concluded that Enbridge Gas should consider both combination IRP Plans (that may include multiple supply-side or demand-side IRPAs or an IRPA in combination with a Facility Alternative) and bridging solutions in its IRP Assessment Process if the bridging solution provides the best alternative in the near term, while exploring longer term solutions.

Enbridge Gas also proposed non-gas IRPAs, specifically electricity-based alternatives. The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. This may be an element of IRP that will evolve as energy planning evolves, and as experience is gained with the IRP Framework.

Enbridge Gas can also seek opportunities to work with the IESO or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas. However, the OEB is not establishing this as a requirement for Enbridge Gas. While in the longer term, there may be an opportunity to have integrated energy resource planning with the optimal fuel choice between all energy sources, the OEB concludes that this would be an excessively challenging requirement during this first-generation IRP Framework. As discussed in chapter 5 ("IRP Framework and Definition of IRP"), directing integrated energy planning between gas and electricity is premature and remains an aspirational goal. Within the Ontario government's review of the long-term energy planning framework, approaches to selecting optimal energy choices may be assessed.

The guidance on IRPAs in the IRP Framework is based on broad categories of alternatives. The OEB concludes that a document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing.

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL AND WEB POSTING

December 1, 2020

To: All Rate-regulated Natural Gas Distributors
All Participants in EB-2019-0003

Re: Post-2020 Natural Gas Demand Side Management Framework
Board File Number: EB-2019-0003

The Ontario Energy Board (OEB) has determined that the best approach for approving a post-2021 Demand Side Management (DSM) plan is for the OEB to consider it through an application process. For that reason, the policy consultation is being concluded. Through this letter, the OEB is inviting Enbridge Gas Inc. to develop and file a comprehensive DSM plan application for DSM programs starting in 2022. The application should include proposed targets, budgets, and programs for the next multi-year DSM plan term. This letter also provides Enbridge Gas with initial guidance to assist it in developing its application, although the proposals made by Enbridge Gas will ultimately be at the discretion of the company.

Background

The OEB began a policy consultation, to be completed in stages, through a letter dated May 21, 2019. Following a Phase 1 Stakeholder Meeting on June 13, 2019 to receive input on the scope of the consultation and the goals and objectives, the OEB indicated that it would undertake a comprehensive review of the current framework for the purpose of establishing a new framework.

In a letter issued on December 19, 2019, the OEB initiated Phase 2 of the consultation and provided a draft consultation plan identifying topics for discussion. The OEB held a Phase 2 Stakeholder Meeting on January 28, 2020 to seek input on the consultation plan and general framework ideas.

On July 16, 2020, the OEB issued a Decision and Order approving a one-year extension for Enbridge Gas Inc. to continue delivering DSM programs under the existing framework throughout 2021.

OEB Direction

Given the passage of time, and in an effort to achieve efficiencies and increase the timeliness of OEB approval of a new multi-year natural gas DSM plan, the OEB is concluding the consultation process in favour of an adjudicative process. The OEB invites Enbridge Gas to file a comprehensive multi-year DSM plan application for the OEB to review new conservation programs, budgets, and targets for the post-2021 period. With the existing 2015-2020 DSM framework set to expire on December 31, 2020, forgoing additional pre-hearing consultation will allow the process to be streamlined through the OEB's adjudicative process. The OEB and interested parties will have the opportunity to undertake a detailed review and comprehensive analysis of the application in order to assess the value and merit of all proposals related to ratepayer-funded DSM programs. This will ensure that the initial goal of the policy consultation, which was to undertake a comprehensive review of the central elements of a DSM plan, can still be achieved.

Enbridge Gas's DSM plan application should be informed by the results of the 2015-2020 DSM plans, the OEB's Mid-Term Review Report, the 2019 Achievable Potential Study, information received through the post-2020 DSM consultation to date, and the government's policies and commitments in the Environment Plan as they continue to evolve, including as expressed in the November 27, 2020 letter from the Associate Minister of Energy and the Minister of the Environment, Conservation and Parks to the OEB regarding the Ontario government's current policy objectives related to DSM.

The OEB's overall objectives for ratepayer funded DSM and key guidance on the main elements of natural gas DSM plans are provided below to allow Enbridge Gas to develop an application for a new multi-year DSM plan that will be subject to a hearing by the OEB. The panel of commissioners hearing the application, however, will ultimately make its decision based on the evidence and arguments before it.

Objectives and Costs of Ratepayer-Funded Natural Gas DSM

As part of Phase 1 of the OEB's consultation, the OEB received written comments from 25 stakeholders regarding the goals and objectives of ratepayer-funded DSM. Following its review and consideration of the submissions, the OEB is of the view that the primary objective of ratepayer-funded natural gas DSM is assisting customers in making their homes and businesses more efficient in order to help better manage their energy bills.

In working towards the primary objective, Enbridge Gas's future ratepayer-funded DSM plan should also consider the following secondary objectives:

- Help lower overall average annual natural gas usage
- Play a role in meeting Ontario's greenhouse gas reductions goals
- Create opportunities to defer and/or avoid future natural gas infrastructure projects[1]

These secondary objectives balance input received from stakeholders and refine the objectives included in the former 2015-2020 DSM framework. The OEB is of the view that these secondary objectives are important considerations that a well-planned and effectively implemented DSM plan can help achieve.

Over the course of the 2015-2020 term, annual OEB-approved natural gas conservation budgets have doubled from the previous levels approved for the 2012-2014 term, up to approximately $140 million per year by the end of the current term. With COVID-19 creating many financial hardships, energy conservation has a role in helping to reduce energy costs and assist customers in managing their energy bills. The OEB anticipates modest budget increases to be proposed by Enbridge Gas in the near-term in order to increase natural gas savings, and expects Enbridge Gas to seek to improve the cost-effectiveness of programs. However, the appropriate level of ratepayer funding expended for DSM programs must weigh the cost-effective natural gas savings to be achieved against both short-term and long-term customer bill impacts.

The OEB expects that all requests for ratepayer-funding to support DSM programs be accompanied by detailed evidence that shows how the programs will benefit Ontario's natural gas customers, help reduce overall natural gas usage and costs, and contribute towards meeting the Government's goals to reduce greenhouse gas emissions.

DSM Programs

Based on the OEB's evaluated results of the 2015 to 2018 DSM programs, while still cost-effective, the level of natural gas savings achieved through DSM programs for each dollar spent has been decreasing. This may be related to Enbridge Gas striving to

[1] DSM can avoid or defer infrastructure passively (by reducing overall natural gas use and infrastructure needs) or actively (by targeting specific infrastructure projects). The OEB has an ongoing hearing that is considering Enbridge Gas's proposed Integrated Resource Planning framework (EB-2020-0091). As part of that proceeding, the OEB will decide on the relationship between the IRP framework and future utility DSM plans and the extent to which Enbridge Gas will be expected to meet this secondary objective as part of its future DSM plan.

meet a number of different priorities, programs being extended to harder-to-reach customers, and recent updates to outdated assumptions.

The OEB expects Enbridge Gas to seek out elements of current programs that can be modified and consider new programs in order to optimize overall program results to make the best use of ratepayer funding. When reviewing its current suite of programs and potential future programs, Enbridge Gas is expected to consider input received through the post-2020 DSM framework consultation, lessons learned from the past six years of activity, the OEB's evaluation reports and recommendations from the Evaluation Contractor, stakeholder feedback from the Mid-Term Review consultation and the recent 2021 DSM plan proceeding, the 2019 Achievable Potential Study, as well as the Government's Environment Plan as it continues to evolve.

For example, Enbridge Gas is encouraged to find ways to increase the natural gas savings from its programs by reducing free ridership, targeting key segments of the market, including low-income and on-reserve First Nations communities, and customers with significant room for efficiency improvements, and strategically incenting customers to achieve more savings. Consistent with the OEB's direction provided in the OEB's Mid-Term Review Report, Enbridge Gas is expected to be actively screening potential program participants thoroughly, and actively seeking out customers who can most greatly benefit from the programs, thereby ensuring program funds are used as efficiently as possible. Further, the OEB expects that all programs continue to be cost-effective as defined in the Mid-Term Review Report.

Additionally, consistent with the Ministerial Directive issued to the Independent Electricity System Operator (IESO) on September 30, 2020, the OEB expects that Enbridge Gas will endeavor to coordinate the delivery of DSM programs with electricity CDM programs where possible, including modifying the participant eligibility requirements of its current low-income program in order to be consistent with the electricity income-tested CDM program eligibility requirements. The centralization of electricity CDM programs under the IESO may lead to new opportunities for DSM-CDM collaboration and a greater level of overall energy savings. The OEB expects Enbridge Gas to file evidence addressing linkages to the new electricity CDM framework and to identify opportunities for efficiencies, program cost reductions, and increased natural gas savings.

Targets, Metrics and Shareholder Incentives

The OEB completed an updated Achievable Potential Study in October 2019. The study was integrated with the IESO with the objective of identifying and quantifying energy savings (electricity and natural gas), greenhouse gas emissions reductions and associated costs from demand side resources for the period from 2019 to 2038. While not determinative, the OEB expects that the findings from the study will be used to inform future natural gas DSM plans.

Further, the OEB is generally supportive of continuing the use of a utility shareholder incentive as a reward for meeting or exceeding performance targets. The OEB expects that future performance be assessed relative to measurable, outcome-based metrics. Additional metrics should also be proposed to ensure all segments of the market are reached and small volume, low-income customers and on-reserve First Nations communities are well-served. The OEB encourages Enbridge Gas to develop a longer-term natural gas savings reduction target, separate from the annual targets, that it will work to achieve by the end of the next multi-year DSM term.

Evaluation, Measurement and Verification

The OEB will continue to provide annual oversight of DSM programs through its role in leading the evaluation, measurement and verification (EM&V) activities. The OEB expects that all future process evaluations undertaken by Enbridge Gas will be included in the OEB's EM&V Plan. These evaluations assess the design and delivery of programs, and all scope of work documents and deliverables will be reviewed by the OEB's Evaluation Advisory Committee and the OEB's Evaluation Contractor.

Additionally, as part of its application for a new multi-year DSM plan, Enbridge Gas is expected to provide information on how it has refined its processes and improved its tracking databases, as recommended by the OEB's Evaluation Contractor, to support the OEB's evaluation process, reduce costs and increase efficiencies.

Term

The OEB expects that Enbridge Gas's new multi-year DSM plan will be for a minimum term of three years up to a maximum of six years, including 2022. Enbridge Gas may consider it necessary to maintain some elements from its 2021 DSM Plan as part of its proposed 2022 DSM Plan to potentially act as a transition to the next multi-year DSM plan. Enbridge Gas should specify in its DSM Plan application by when approval of its 2022 DSM Plan would be required in order to ensure program continuity. Alternatively, Enbridge Gas may file a separate application for 2022.

Next Steps

At a minimum, the OEB expects Enbridge Gas to submit an application for a new DSM plan that includes proposed targets, budgets, programs, and performance metrics no later than May 1, 2021.

As the OEB's main objective for DSM is relevant to all Ontario natural gas customers, the OEB encourages EPCOR Natural Gas Limited Partnership to consider filing its own DSM plan. The OEB appreciates that any DSM plan filed by EPCOR would need to be devised and assessed in a different manner than that of Enbridge Gas, however, the objectives outlined in this letter are still relevant to EPCOR.

The OEB thanks all participants for their contributions to the consultation. A Notice of Hearing for Cost Awards regarding the remaining activities not yet addressed will be issued separately.

Yours truly,

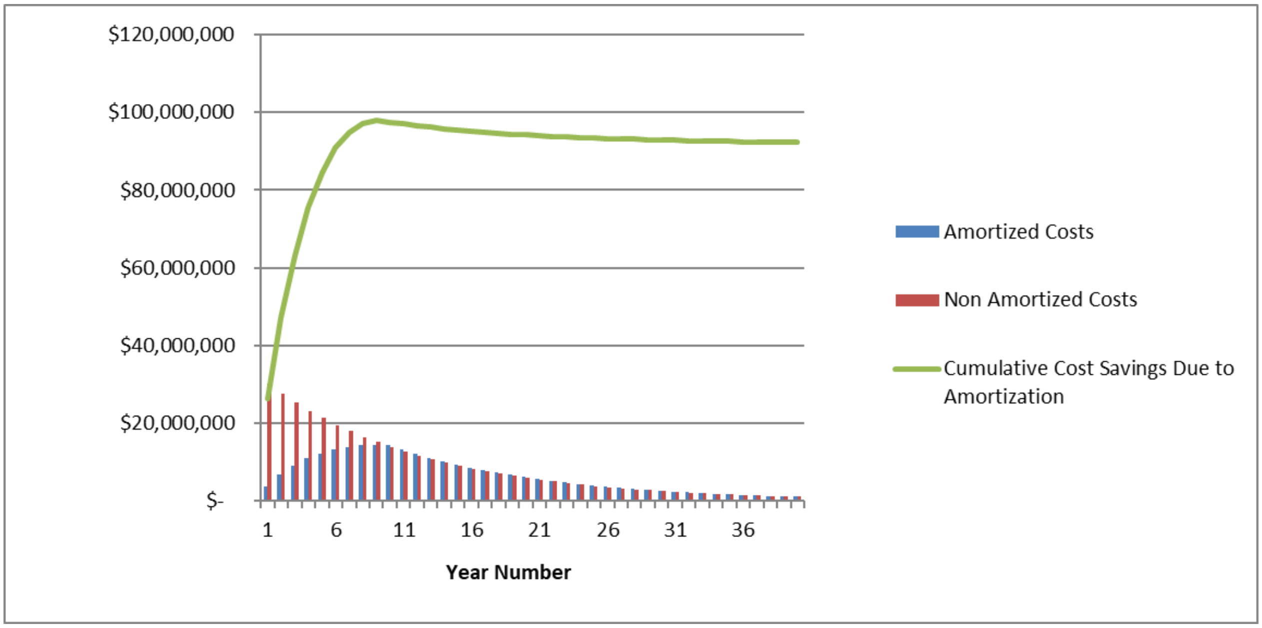
Original Signed By

Christine E. Long
Registrar

Pay For Performance (P4P) Draft Metrics: K-12 Schools

Building Type	Total Gas Savings During Program (m3)	Total P4P Lifetime Gas Savings (m3)	Total Incentive Cost ($)	Total Administrative Cost ($)	Total Technical Cost ($)	Total Participant Cost ($)	Total Program Costs ($)	Total Cost of Savings ($/m3)	TRC-Plus Ratio
Schools (K-12)	23,898,880	119,494,398	8,364,608	1,194,944	1,194,944	4,596,421	15,350,917	0.13	2.50

Table E1: Cumulative Cost Savings from Amortization – 10% Discount Rate, 4% Interest Rate



We also examine cost recovery approaches in Maryland, Illinois, New Jersey, New York, Utah, Delaware and Missouri and discuss the approach to amortizing energy efficiency expenses, highlighting varying amortization periods and interest rates.

In Enbridge's interrogatory responses, they indicate that based on their interpretation of the OEB's December 1, 2020 guidance that indicated "the OEB anticipates modest budget increases to be proposed by Enbridge in the near-term…", that amortization is likely not necessary. While this position seems reasonable if budgets are staying relatively flat, amortization could be appropriate for Ontario in the future as a way to fund an expansion in efficiency efforts while minimizing rate impacts.

When considering what cost recovery model to use, it is important to properly value the costs in the near and long-term. This is why it is important to use a net present value approach that applies a reasonable discount rate to efficiency costs so that they are appropriately valued in the analysis informing the decision of what cost recovery model is most appropriate. Based on the OEB's findings regarding what cost recovery model to use, we recommend that a single cost recovery approach (amortization or full annual cost recovery) should be used for all programs and sectors to avoid the complexity involved in using different approaches for different programs.

Optimal recommends considering the following factors should amortization of natural gas conservation costs be implemented in Ontario:

- **Amortization Consideration 1: Interest rate** – the selected interest rate can have a large impact on the success of amortization and should be set at a low rate, such as the utility's cost of debt. Interest rates used in jurisdictions with amortization range from the utility rate of return in Maryland, to the short-term carrying cost of debt, used in Missouri. While using the rate of return will align demand side spending most closely with supply

Enbridge Gas Inc. - Annual Gas Cost

	2015	2016	2017	2018	2019	2020
Total Ontario gas consumption (10^6m^3)[1]	25,702	24,564	24,533	26,088	26,704	25,065
Total Ontario gas customers[2]	3,540,089	3,598,700	3,653,986	3,701,403	3,717,399	3,740,847
Total Ontario gas consumption for which Enbridge has commodity price data (10^6m^3)	12,102	11,249	12,066	13,460	13,753	12,441
Average annual commodity price (for gas that Enbridge has data for) ($/m^3$)	$ 0.138	$ 0.106	$ 0.125	$ 0.111	$ 0.119	$ 0.100
Annual commodity costs (for gas that Enbridge has data for) ($000)	$ 1,673,729	$ 1,196,865	$ 1,514,111	$ 1,490,445	$ 1,640,834	$ 1,245,103
Annual commodity costs (estimate other customers)[3]	$ 1,873,562	$ 1,319,030	$ 1,740,315	$ 1,556,562	$ 1,633,807	$ 1,243,629
Annual distribution costs ($000)[4]	$ 1,972,233	$ 1,982,456	$ 2,074,811	$ 2,274,557	$ 2,350,719	$ 2,314,764
Annual carbon costs ($000)[5]	$ -	$ -	N/A	N/A	$ 347,142	$ 809,072
Annual other gas related costs ($000)[6]	$ 949,082	$ 870,798	$ 783,655	$ 823,991	$ 703,701	$ 604,447
Total annual gas costs (for gas that Enbridge has data for) – ($000)	**$ 4,595,044**	**$ 4,050,119**	**$ 4,372,577**	**$ 4,588,992**	**$ 5,042,397**	**$ 4,973,387**
Total gas consumption not applicable to the Federal Carbon Charge (10^6m^3)[7]	N/A	N/A	N/A	N/A	5,858	8,781

[1]Annual gas volumes include quantities of gas sold to system gas customers and quantities of gas delivered to direct purchase customers. Source: OEB Natural gas distributor yearbooks

[2]Total customers include system gas customers and direct purchase customers of gas marketers licensed by the OEB. Source: OEB Natural gas distributor yearbooks

[3]Estimate is calculated using direct purchase customer volumes and apply to the commodity prices equal to Enbridge system gas customers

[4]Fixed and Variable, please refer to Exhibit I.GEC.4 for the breakdown by rate class

[5]2017 & 2018: These costs were filed as strictly confidential in EB-2018-0331; 2019: Refer to EB-2019-0247, EGI Updated Federal Carbon Pricing Program Application (May 14, 2020), Exhibit C, p.11-12

[6]Other costs include transportation cost, load balancing & storage costs. Please refer to Exhibit I.GEC.4 for the breakdown by rate class

[7] Totals include exempt volumes delivered to downstream distributors, mandatory and voluntary participants in the Output-Based Pricing System, volumes qualifying for exemption for non-covered activities and partial relief (80%) for greenhouse operators. For 2019, the volumes only represent April-December 2019 as the Federal Carbon Charge was not implemented until April 1, 2019.

Enbridge Gas Inc. - Annual Gas Cost

	2023	2024	2025	2026	2027
Total Ontario gas consumption (10^6m^3)[1]	N/A				
Total Ontario gas customers[2]	N/A				
Total Ontario gas consumption for which Enbridge has commodity price data (10^6m^3)	14,457	14,504	14,554	14,610	14,665
Average annual commodity price (for gas that Enbridge has data for) ($/m^3$) [3]	$ 0.122	$ 0.122	$ 0.122	$ 0.122	$ 0.123
Annual commodity costs (for gas that Enbridge has data for) ($000)	$ 1,762,818	$ 1,774,854	$ 1,779,680	$ 1,788,883	$ 1,797,650
Annual commodity costs (estimate other customers)[4]	$ 1,462,000	$ 1,472,479	$ 1,469,958	$ 1,473,729	$ 1,477,049
Annual distribution costs ($000)[5]	$ 2,193,449	$ 2,208,275	$ 2,271,351	$ 2,422,542	$ 2,451,582
Annual carbon costs ($000)[6]	$ 2,202,930	$ 2,724,157	$ 3,242,034	$ 3,777,393	$ 4,308,557
Annual other gas related costs ($000)[7]	$ 804,052	$ 711,318	$ 754,775	$ 807,502	$ 697,397
Total annual gas costs (for gas that Enbridge has data for) ($000)	**$ 6,963,249**	**$ 7,418,604**	**$ 8,047,840**	**$ 8,796,321**	**$ 9,255,187**
Total gas consumption not applicable to the Federal Carbon Charge (10^6m^3)[8]	9,346	9,447	9,491	9,510	9,569

[1]Annual gas volumes forecast for the province of Ontario is not available. Please refer to Exhibit I.GEC.3 for the total volume forecast for Enbridge Gas

[2]Total customers forecast for the province of Ontario is not available. Please refer to Exhibit I.GEC.3 for the total customer forecast for Enbridge Gas

[3]Estimate commodity prices are based on the Board-Approved April 2021 QRAM

[4]Estimate is calculated using direct purchase customer volumes and apply to the commodity prices equal to Enbridge system gas customers

[5]Fixed and Variable, please refer to Exhibit I.GEC.4 for the breakdown by rate class. The estimated gas cost are calculated based on the current rates and rate class structures which may change as a result of the rate harmonization effort that is currently ongoing in anticipation of filing the Rebasing application at the end of 2022.

[6]This forecast only represents customer related carbon costs as Enbridge Gas does not complete long-range volume forecasts related to our facility operations beyond 2022. Please refer to Exhibit I.Anwaatin.2 for more information on these forecasts.

[7]Other costs include transportation cost, load balancing & storage costs. Please refer to Exhibit I.GEC.4 for the breakdown by rate class

[8] Forecast includes exempt volumes delivered to downstream distributors, mandatory and voluntary participants in the Emissions Performance Standards, volumes qualifying for exemption for non-covered activities and partial relief (80%) for greenhouse operators.

ENBRIDGE GAS INC.

Undertaking Response to OEB Staff

Undertaking

Tr: 64

Enbridge to propose or provide a weighted average measure life for its portfolio for the pending term from 2023-2027; a threshold which the company should keep the portfolio above.

Response:

While Enbridge Gas will maintain appropriate flexibility, within the parameters outlined in the proposed DSM Framework and the Company's DSM plan proposal, to shift resources between programs and program offerings to effectively pursue results and maximize gas savings opportunities, Enbridge Gas commits to exercise this flexibility in a way that aims to maintain a minimum threshold portfolio weighted average measure life (WAML).

The forecast portfolio weighted average measure life (WAML) of Enbridge Gas's plan for the 2023 program year is 16.4 years[1] on a net basis.

In conjunction with the Company's DSM plan proposal which assesses results for most programs based on annual net gas savings metrics, Enbridge Gas proposes it will operate its portfolio with the goal of maintaining a minimum WAML threshold (minimum WAML threshold) of 13.12 years[1] (i.e. not more than 20% below the annual DSM plan forecast WAML) based on portfolio level annual net gas savings, with the following provisions:

i. The portfolio WAML will be calculated as the sum of a program year's cumulative net gas savings divided by the sum of that program year's net annual gas savings.
ii. The portfolio WAML calculation will exclude the Large Volume program results due to the self-direct design of the program which limits the ability of the utility to prioritize longer measure life projects with this customer group.
iii. The WAML calculation and the minimum WAML threshold will be subject to adjustments to account for changes in measure life assumptions outside of the utilities control, i.e. updates to TRM measure lives and the Custom Measure Life table as may be revised as part of the annual TRM review process.

[1] This value is based on the specific program and target proposals outlined by Enbridge Gas in its 2023-2027 DSM plan application, any changes proposed to this program and target composition will require a recalculation of the WAML and minimum WAML threshold upon which this guidance is proposed by the Company.

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BY E-MAIL

January 26, 2022

Nancy Marconi
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Update to OEB Staff Expert Evidence
Enbridge Gas Inc. – EB-2021-0002
Application for new DSM Framework and 2022-2027 DSM Plan

On December 1, 2021, OEB staff filed expert evidence produced by Optimal Energy Inc. The evidence contained two reports. After reviewing the interrogatories filed in relation to the evidence, Optimal Energy identified a factual error in Exhibit L.OEB Staff.1 where several references to Missouri's cost recovery structure were incorrect. The report has been updated to correct these errors with updated jurisdictional references.

As a result, and consistent with Section 11.03 of the OEB's Rules of Practice and Procedure, OEB staff is filing updates to Exhibit L.OEB Staff.1 as set out in the Table 1:

Table 1 – Exhibit Reference and Summary of Updates

Ex L.OEB Staff.1	Update
p. ii-iii	Corrected references to jurisdictions noted in the report.
p. iii	Corrected references to jurisdictions noted in the report.
p. 7	Corrected references to jurisdictions noted in the report.
p. 13-14	Correction to Table 5 – Summary of Jurisdictions Using Amortization for Cost Recovery
p. 14	Corrected references to jurisdictions noted in the report.
p. 17	Correction to description of treatment of amortized costs and performance incentives

Yours truly,

Josh Wasylyk

Digitally signed by Josh Wasylyk
Date: 2022.01.26 14:58:08 -05'00'

Josh Wasylyk
Senior Advisor – Application Policy & Conservation

cc: All parties in [EB-2021-0002]

SUPPLEMENT A - OEB'S INFORMATION AND REQUIREMENTS

1.1 PROJECT INFORMATION

Project Name: Post-2020 Demand Side Management (DSM) Policy Framework for Natural Gas Distributors – Expert Analysis and Recommendations related to Natural Gas DSM Cost Recovery Approaches, Shareholder Incentive Models and Natural Gas DSM Best-in-Class Program Jurisdictional Review

VOR Subject Area(s):

1) Climate Change

VOR Topic Area(s):

1) Cap and trade regulatory frameworks
2) Carbon pricing forecast
3) Conservation policy frameworks
4) Conservation potential studies
5) Evaluation, measurement and verification of conservation programs (EMV) including net to gross studies, impact and process evaluation and market effects
6) Marginal abatement cost curves and cost effectiveness evaluation
7) Renewable and distributed generation
8) Technology assessment

Anticipated Project Start Date:

The OEB expects that the final deliverables will be completed within approximately two (2) months following the start of the engagement.

Supporting services could be required for the duration of the post-2020 DSM framework policy consultation (EB-2019-0003).

Vendors will be asked to consider these approximate timelines when preparing their bids, and should include within their bids a proposed schedule for Tasks 1, 2, 3 and 4.

Task 5 – Supporting Services could extend for up to one (1) year.

Project End Date:

The term of the engagement is for one (1) year with an option for the OEB, in its sole discretion, to extend it for one (1) additional one-year term.

1.2 BACKGROUND INFORMATION

1.2.1 Project Background:

Overview

The OEB intends to retain a vendor to provide support for the development of the post-2020 policy framework for natural gas demand side management (DSM).

DSM provides opportunities for natural gas customers to improve the energy efficiency levels within their homes and businesses in an effort to reduce overall natural gas usage and associated greenhouse gas emissions, help manage energy costs and play a role in potentially deferring or avoiding future infrastructure development.

The OEB has had policy guidance related to ratepayer-funded and utility-delivered DSM programs since 1993. Policy guidance has been updated in 2006, 2012 and most recently for the period of January 1, 2015 to December 31, 2020, including the OEB's Mid-Term Review Report.

The current 2015-2020 DSM Framework was developed following a March 31, 2014 directive from the Ontario Minister of Energy. Following the release of the OEB's DSM Framework, the two large gas utilities in Ontario, Enbridge Gas Distribution Inc. and Union Gas Limited, filed proposed multi-year DSM plans. On January 20, 2016, the OEB issued its Decision and Order related to the gas utilities' 2015-2020 DSM Plans. The approved annual budgets for the two utilities to implement natural gas DSM programs for residential (including low-income), commercial, and industrial (including large volume) customers are outlined in the table below:

Table 1 - Enbridge and Union 2015-2020 OEB-approved annual DSM budgets

Utility	2015	2016	2017	2018	2019	2020	2015-2020 Total
Enbridge Gas	$37.7M	$56.4M	$62.9M	$67.6M	$66.4M	$67.8M	$358.8M
Union Gas	$34.0M	$56.8M	$58.6M	$63.3M	$63.3M	$64.3M	$340.3M
TOTAL	**$71.7M**	**$113.2M**	**$121.5M**	**$130.8M**	**$129.7M**	**$132.1M**	**$698.1M**

In September 2019, the OEB announced that it is undertaking a comprehensive review of the current DSM policy framework (EB-2019-0003). The scope of the review will include consideration of the objectives to be achieved by DSM activities, targets, program mix, budgets (including cost recovery models) and how utility performance should be incentivized and measured.

The OEB is consulting with interested parties in the development of the post-2020 DSM framework. To-date, the OEB has sought feedback on the scope of the review, the goals, objectives and guiding principles of the post-2020 DSM framework, and the consultation plan.

1.3 OEB'S REQUIREMENTS

The objectives of this Project will be to:

1. Develop a report that provides expert analysis of cost recovery approaches (e.g. amortizing energy efficiency program costs) and performance-based shareholder incentive models to maximize overall results, including natural gas savings and reductions in customers' energy costs. Review of other jurisdictions should be considered, for example Commonwealth Edison and Ameren in Illinois, PSE&G in New Jersey, Rocky Mountain Power in Utah and EmPower in Maryland that have incorporated an amortization approach. The report should ultimately provide recommendations for natural gas DSM cost recovery approaches and performance-based shareholder incentive models in Ontario; and

2. Undertake a jurisdictional review of best-in-class natural gas energy efficiency programs across all sectors and customer classes and provide recommendations on programs or specific program components that should be considered for inclusion as part of future natural gas DSM programs in Ontario; and

3. Provide supporting services, as needed, to provide information regarding the contents of the report as part of stakeholder consultations.

1.3.1 Purpose and Scope:

The purpose of this project is to contribute to the OEB's policy review to develop a new DSM framework by generating expert analysis of natural gas DSM cost recovery approaches and performance-based shareholder incentive models, as well as a review of best-in-class natural gas DSM programs and recommendations on considerations for future programs in Ontario. This research project is intended to assist OEB staff and stakeholders as part of the policy consultation process and ultimately, the OEB in its determination of appropriate policy guidance related to future DSM activity in Ontario.

The scope of this project will be to develop two expert reports and to provide supporting services as needed. Supporting services could include attending stakeholder consultation meetings, and presenting the report's conclusions to internal and external parties.

1.3.2 Mandatory Requirements

Vendors must have sufficient resources available to address the scope of services required in accordance with the timelines indicated in this RFS.

1.3.3 Project Requirements (Description of Specific Deliverables/Milestones):

Task 1: Develop Work Plan for the Cost Recovery Approaches and Performance-based Shareholder Incentive Models Report

Vendors are asked to provide a draft work plan and schedule to complete the cost recovery and shareholder incentive models report as part of their bids. The draft work plan should provide sufficient detail for the OEB to assess what information-gathering and analytical techniques will be used to develop the cost recovery and shareholder incentive models report (e.g. whether research will involve the use of documents in the public record, proprietary information/tools/knowledge of vendor, informational interviews, etc.). This work plan will be finalized based on discussion with OEB staff, and potentially interested stakeholders in the policy consultation, after the successful vendor has been selected.

Deliverables

1. **Final Cost Recovery and Shareholder Incentives Report Work Plan:** finalized based on discussion with OEB staff.

Task 2: Report on Natural Gas Demand Side Management Cost Recovery Approaches and Performance-based Shareholder Incentive Models

The cost recovery approaches and shareholder incentive models report will focus on considerations needed for the OEB to determine if it is appropriate to change the DSM cost recovery model, or parts of the DSM cost recovery. The current cost recovery model allows for DSM expenses and performance-based shareholder incentives to be recovered on an annual basis proportionally from all customer rate classes.

The OEB is interested in understanding more about different cost recovery approaches, particularly an amortization approach that treats DSM costs similar to capital investments and allows DSM costs to be amortized over a certain period of time.

The vendor is also expected to consider if and how performance-based shareholder incentives can or should be altered from the current model that rewards a utilities' annual achievement relative to various metrics across multiple scorecards up to a maximum absolute incentive amount, to a different model that prioritizes and motivates maximizing overall natural gas savings, reducing customers' energy costs and deferring or avoiding future infrastructure projects.

The OEB expects that, at a minimum, the cost recovery and shareholder incentives report would include the following information:

- A general description of at least three current examples where provincial, state or regional energy efficiency and conservation costs are amortized, and the experience to-date of those models, including overall costs, costs as a percentage of customer's bills, and overall energy reduction targets. Preference should be given to natural gas conservation examples, but electricity conservation examples can also be included where there are no natural gas examples.

- A comparison of the current cost recovery approach in Ontario to other cost recovery approaches that discusses the following:
    - Whether there are cost recovery approaches, other than the current Ontario model where costs are recovered on an annual basis or amortization approach, that Ontario should consider
    - Amortization period
    - Return on equity for demand-side investments relative to traditional infrastructure investments
    - Impacts on customer bills and annual rate impacts
    - Equitability of amortizing costs
    - Inclusion of penalties for not meeting targets
    - Time period used as basis for DSM budgets, performance incentives and targets (e.g. single-year vs. multi-year)
    - Implementation of new programs and changes to existing programs at various points during a multi-year plan
    - Programs, measures, sectors and other utility DSM costs best suited for amortization
    - Utility focus on cost-effective energy efficiency relative to other investments
- A comparison of Ontario's energy policy, resource mix and conservation efforts to jurisdictions that have transitioned to an amortization cost recovery model.
- A comparison of Ontario's natural gas DSM shareholder incentive model to the shareholder incentive model of at least three other leading jurisdiction's natural gas energy efficiency programs, including key policy considerations that govern natural gas energy efficiency program activity, overall policy goals and maturity and sophistication of program delivery.
    - As part of the review of shareholder incentive models, the vendor is expected to provide the linkages to the cost recovery model(s) and how best the two should be aligned. Additional analysis should also be included, including risks to various shareholder incentive models.
- Recommendations from the vendor regarding the appropriateness of transitioning, either in part or exclusively, Ontario natural gas DSM costs to a different cost recovery approach and/or performance-based shareholder incentive model.

Vendors are asked include a draft Table of Contents (ToC) for the cost recovery and shareholder incentives report as part of their bids. The draft ToC of the successful vendor will then be refined and finalized based on discussion with OEB staff, and potentially stakeholders in the post-2020 DSM framework policy consultation (EB-2019-0003).

The vendor is asked to submit a draft cost recovery and shareholder incentives report to OEB staff for review. The vendor should plan for at least two meetings with OEB staff (one prior to finalizing the ToC, likely in conjunction with finalizing the work plans (Task 1 and Task 3) and jurisdictional review criteria (Task 4), and one subsequent to submitting the draft cost recovery and shareholder incentives report and draft jurisdictional review (Task 4), with communication via phone/e-mail as needed between these milestones. The vendor should also plan on making up to two presentations of its findings, one potentially to OEB staff and

As our primary research develops, Optimal will regularly check in with the OEB to discuss preliminary high-level findings and recommendations to ensure our ultimate report effectively meets the needs and interests of the OEB. We will then write a draft report, and submit it to the OEB for review and comment. Once this draft is submitted, Optimal will meet with the OEB and other stakeholders to present and discuss the findings and recommendations. We expect to receive comments at this meeting, as well as more formal written comments from the OEB. We will update the draft report as necessary and submit a final version.

Deliverables

- Draft for the Cost Recovery Approaches and Performance-based Shareholder Incentive Models Report
- Final for the Cost Recovery Approaches and Performance-based Shareholder Incentive Models Report
- Presentation of Report Findings and Recommendations

COST RECOVERY AND PERFORMANCE INCENTIVE SCHEDULE

	Week of									
	3-Aug	10-Aug	17-Aug	24-Aug	31-Aug	7-Sep	14-Sep	21-Sep	28-Sep	5-Oct
Kick-off Meeting										
Finalize Work Plan and Table of Contents										
Research Other Jurisdictions										
Draft Report										
Submit Final Report										

Proposed dates for key milestones include:

- Aug 5 – Kick-off meeting
- Aug 12 – Final Work Plan and Table of Contents
- July 27 – Final Work Plan and Table of Contents
- September 18 – Draft Report
- September 23 – Meeting to discuss Draft Report
- September 25 – Comments on Draft Report
- Oct 2 – Final Report
- Oct 9 – Presentation on Final Report

(d) We do not advise using an amortization period that is longer than the weighted average measure life, as it would mean that ratepayers would have to continue paying off the program costs after they have stopped producing any benefits. Amortizing over the average measure life sufficiently places energy efficiency on similar financing footing as pipeline costs as in both cases costs are paid over the time that the investment will produce benefits.

Interrogatory from Pollution Probe

5-PP-2-OEB Staff.1

Reference:

Exhibit L.OEB Staff.1

Preamble:

There are two main ways to recover efficiency program costs:

- Under full contemporaneous cost recovery, efficiency program costs are fully recovered in rates each year.
- Under amortization, program costs are treated more akin to capital costs, and financed over a fixed loan term.

Question(s):

(a) What option is the best if a proponent wanted to maximize DSM value for Ontario consumers and communities?

(b) What option aligns best with delivering the increased DSM results proposed in the Ontario Environment Plan and the Ontario DSM Potential Study?

(c) What option aligns best with the outcomes outlined in the OEB's 2021 Mandate letter (Reference: EB-2021-0002 Procedural Order No. 6, Schedule A)

Response

(a) Both funding models can maximize DSM value for Ontario. However, if a significant ramp up in DSM spending is needed in order to maximize value, then an amortization model can do this with lower impact on short- and medium-term rates.

(b) See above.

(c) The letter appears to indicate a desire for increased efficiency funding. If a ramp up in DSM funding is hindered due to concerns around higher short-term rates, then cost amortization may align better.

Interrogatory from Pollution Probe

5-PP-3-OEB Staff.1

Reference:

Exhibit L.OEB Staff.1

Preamble:

Recommendation 4:
We recommend a process to allow updates, or midterm modifications, of the targets during the 2023-2027 term.

Question(s):

Midterm assessments and adjustments have typically not been made by the OEB for DSM portfolios, even though they have been part of the process for decades. Which best practice recommendations are available to better enable midterm adjustments under the DSM Framework?

Response

Absent a major change in market conditions, we don’t think it’s appropriate to change the goals mid-term. We recommend this as an alternative to the proposed Target Adjustment Mechanism (TAM), where savings targets are set based on achieved savings from the previous year, because we believe savings targets should be set for the entire plan cycle. Under our recommendation, targets would be set for every year of the plan in advanced. However, if market conditions changed enough where Enbridge felt it not possible to meet the spending and savings targets, they could petition the OEB to convene a stakeholder/regulatory process where they propose updated targets and make the case for why they are necessary. This would resemble a streamlined version of the process used to approve the current application and would ultimately need buy-in from regulators and/or other stakeholders.

2.1.3. Cost of Capital

2.1.3.1. Cost of Capital Applied in Other Jurisdictions

Table 4 shows the costs of capital used in the other North American jurisdictions that amortize DSM investments. Again, this table is similar to Table 6 presented in the Optimal report, with the updates noted earlier for British Columbia and Missouri. I also reorganized my Table 4 in an attempt to bring some consistency and clarity to the information. My Table 4 uses consistent language to describe the cost of capital applied in each state (where the Optimal report appeared to use a variety of terms interchangeably (e.g., "Approved Rate of Return", "Rate of Return", "Weighted Average Cost of Capital", "utility carrying costs"). The Optimal report also provided details on performance incentives where those are factored into the cost of capital; I do not address those in detail, since I address performance incentives in Section 3.

Table 4: Amortization Cost of Capital Applied in Other Jurisdictions

Jurisdiction	Cost of Capital	Optimal Cost of Capital Data[13]	Notes
Jurisdictions Not Currently Adjusting Cost of Capital for Performance			
BC	Approved WACC*		
DE	Approved WACC	Approved rate of return	
MD	Approved WACC	Approved rate of return	
NJ	Approved WACC	Approved Rate (return on equity minus 100 basis points) of Return plus or minus up to 50 basis points depending on performance	New Jersey has deferred implementing performance adjustments until at least 2025.
UT	Approved WACC	Weighted average costof capital	
Jurisdictions Applying Performance Adjustment to Cost of Capital			
IL	Formula WACC	Approved rate of return plus or minus up to 200 basis points depending on performance	Illinois calculates return on equity applied in WACC through formula rate process that occurs annually.
NY	PBR+ WACC	Rate of return	New York calculates return on equity applied in WACC through PBR process that includes metrics for DSM portfolio performance.
Jurisdictions Not Amortizing DSM Expenditures			
MO[14]	N/A	Gas Utilities recover program costs at the rate of return. Electric shifted away from amortizing program costs around 2016, but PIs are recovered over approximately 6 years and accrue interest at the utility short term cost of debt.	Missouri electric utilities do not amortize expenditures.
*Approved WACC=weighted average cost of capital (WACC) approved in utility's most recent rate case +PBR=Performance based ratemaking			

[13] Optimal Report, Table 5.
[14] See footnote 9 regarding Missouri treatment in Optimal original and updated reports.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Issue 10

Reference:

Exhibit E, Tab 2, Schedule 2

Preamble:

This question is relevant to a number of other issues aside from the programming for new construction.

Question(s):

(a) Please complete this table as much as is possible. Please make and state assumptions and caveats as necessary. Best estimates are sufficient.

Enbridge Customers – Characteristics by Sector			
	2015	…	2030
Total Enbridge Customers			
Residential			
Commercial			
Industrial			
Average Gas Consumption (m3/yr/customer)			
Residential			
Commercial			
Industrial			
Total Enbridge Customers with Air Conditioning			
Residential			
Commercial			
Industrial			
Total Enbridge Customers with Air Conditioning (central, ducted)			
Residential			
Commercial			
Industrial			

Total Enbridge Customers with Gas Water Heater			
Residential			
Commercial			
Industrial			
Total Enbridge Annual Water Heating Load			
Residential			
Commercial			
Industrial			
Total Enbridge Customers with Other Gas Equipment (e.g. stove)			
Residential			
Commercial			
Industrial			

<u>Response</u>

a) Attachment 1 includes Enbridge Gas's actual and forecast customers and volumes by service type (General Service and Contract market) and sector (Residential, Commercial and Industrial). The Company doesn't have the same level of detail provided for the other customer types requested (with AC, other gas equipment etc.).

Table: Enbridge Gas Customers and Consumption by Service type and Sector

	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030
General Service																
Residential																
Number of Customers	3,237,152	3,285,272	3,334,545	3,381,450	3,424,068	3,463,393	3,503,999	3,542,988	3,581,336	3,619,638	3,656,897	3,694,224	3,730,290	3,764,642	3,797,454	3,828,911
Annual Volumes (106m3)*	7,713	7,676	7,965	8,070	8,224	8,286	8,161	8,252	8,288	8,349	8,377	8,422	8,465	8,521	8,541	8,575
Average use per customer (m3)**	2,383	2,336	2,389	2,387	2,402	2,392	2,329	2,329	2,314	2,307	2,291	2,280	2,269	2,263	2,249	2,239
Small Commercial																
Number of Customers	272,217	274,089	276,298	278,094	280,104	281,893	283,071	285,070	286,603	288,046	289,422	290,719	291,893	292,940	293,877	294,715
Annual Volumes (106m3)*	6,161	6,054	6,313	6,410	6,515	6,440	6,217	6,326	6,384	6,423	6,444	6,479	6,514	6,557	6,581	6,614
Average use per customer (m3)**	22,634	22,088	22,848	23,049	23,258	22,845	21,961	22,192	22,273	22,298	22,264	22,287	22,317	22,384	22,392	22,443
Small Industrial																
Number of Customers	11,322	11,221	11,163	11,095	10,996	10,985	10,982	10,976	10,974	10,973	10,971	10,970	10,969	10,967	10,966	10,965
Annual Volumes (106m3)*	1,163	1,139	1,160	1,159	1,155	1,047	1,053	1,070	1,056	1,051	1,045	1,040	1,035	1,031	1,024	1,019
Average use per customer (m3)**	102,748	101,529	103,933	104,480	105,070	95,297	95,851	97,467	96,212	95,768	95,209	94,777	94,325	94,049	93,344	92,905
Total General Service																
Number of Customers	3,520,692	3,570,581	3,622,006	3,670,639	3,715,168	3,756,270	3,798,052	3,839,034	3,878,914	3,918,658	3,957,291	3,995,913	4,033,151	4,068,550	4,102,297	4,134,591
Annual Volumes (106m3)*	15,037	14,869	15,438	15,639	15,895	15,772	15,430	15,648	15,727	15,823	15,866	15,941	16,014	16,109	16,145	16,207.494
Contract																
Number of Customers	852	881	885	891	905	969	981	988	989	989	989	989	989	989	989	989
Annual Volumes (106m3)*	10,967	10,719	9,513	10,320	10,404	10,394	10,430	10,792	10,997	11,024	11,038	11,129	11,156	11,247	11,261	11,365
Total EGI																
Number of Customers	3,521,544	3,571,463	3,622,891	3,671,530	3,716,073	3,757,239	3,799,034	3,840,021	3,879,902	3,919,646	3,958,279	3,996,902	4,034,139	4,069,538	4,103,286	4,135,579
Annual Volumes (106m3)*	26,005	25,588	24,951	25,959	26,299	26,166	25,860	26,439	26,724	26,847	26,904	27,070	27,170	27,356	27,406	27,572

*Annual Volumes are normalized to 2022 Budget Degree Days

**Normalized average use per customer numbers in table are determined by dividing the total volumes to the total number of customers for each year and sector. All figures shown are for illustration purpose only.

Assumptions		
# of Participants	500	
% Savings	25%	
Avg Size of Participant	191,191	m3/year consumption

Table 1: Updated Enerlife Table JT3.6 page 1

	Total Gas Savings (m3)	Total Lifetime Gas Savings (m3)	Total Incentive Cost ($)	Total Startup ($)	Total Admin Cost ($)	Total Tech Cost ($)	Total Participant Cost ($)	Total Program Cost ($)
Enerlife Analysis	23,898,880	119,494,400	$ 8,364,608		$ 1,194,944	$ 1,194,944	$ 4,596,421	$ 15,350,917
Enerlife Analysis (updated)[1]	23,898,880	119,494,398	$ 11,949,440[2]	$ 100,000	$ 1,194,944	$ 1,194,944	$ 4,596,421	$ 19,035,749
Per Participant Analysis	47,798	238,989	$ 23,899	$ 200	$ 2,390	$ 2,390	$ 9,193	$ 38,071

[1] Start-up costs were not initially included, and due to a miscalculation in the application of the bonus incentive, an update was made.

[2] As per Exhibit E Tab 2 Schedule 1 Page 7 of 10, Performance Incentives @ $0.30/m3 will be based on M&V of incremental gas savings at the meter relative to the baseline model and awarded at the end of each Pay-for-Performance Period on an annual basis.

Bonus Incentives @ $0.20/m3 will be based on M&V of **total gas savings** at the meter at the end of the offer term relative to the baseline model. Incentives will be awarded at the end of the offer if the customer has achieved the 20% performance target.

Table 2: Particpants vs Actual Schools @ 25% savings

# of Participants	Avg m3/participant	Consumption level required toreach goal assuming 25% savings	# of Schools per comption level	Cummulative annual total savings assuming 25% savings per school	Enerlife Estimated Annual M3	% of estimated savings possible
500	48,000	192,000	231	11,088,000	24,000,000	46%
750	32,000	128,000	486	15,552,000	24,000,000	65%
1200	20,000	80,000	938	18,760,000	24,000,000	78%

Source: Energy use and greenhouse gas emissions for the Broader Public Sector - Datasets - Ontario Data Catalogue

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Issue 5

Reference:

Exhibit C, Tab 1, Schedule 1, Page 48

Preamble:

Enbridge states:

> "Assumptions relating to the benefit of not having to supply an extra unit of natural gas or other resource (e.g., electricity, heating fuel oil, propane, or water) through the delivery of DSM programs are referred to as avoided costs. Avoided costs are required to quantify the benefits for the TRC-plus test.
>
> Avoided costs are long-term estimates forecasted over the lifetime of DSM measures and include:
>
> • Avoided natural gas commodity costs
> • Avoided natural gas upstream transportation and third-party services costs
> • Avoided natural gas seasonal storage requirement costs.
> • Avoided unaccounted for natural gas fuel losses
> • Avoided natural gas downstream infrastructure costs[1]
> • Avoided costs, other resources (electricity, heating fuel oil, propane, and/or water)
> • Avoided carbon costs"

Note that this question is also relevant to a number of other issues, including issue 13 (appropriateness of avoided cost input assumptions) and 10 (optimal suite of program offerings). Please feel free to move it to a different section of the interrogatory responses. This information is also important to promote consistency between intervenor evidence and Enbridge's evidence.

[1] [Footnote 61] "For DSM this reflects passive avoided distribution costs driven by broad-based DSM programs, rather than active/geo-targeted avoided distribution costs unique to a specific initiative."

Question(s):

(a) Please provide a live excel spreadsheet (or spreadsheets) containing a full breakout of all of the prices and inputs for the avoided cost calculations underlying Enbridge's application (e.g. $/m^3, $/kWh, etc.).

(b) For each of the avoided cost categories listed above, please indicate the approximate date that the forecast of future costs was made.

(c) Please provide a table (ideally as an excel spreadsheet) showing the forecast carbon price for avoided carbon costs for each year both as $/tonne CO2e and as $/m^3 of gas.

(d) Please describe the rationale for Enbridge's forecast avoided carbon price in 2031 and beyond.

(e) Please provide a table (ideally as an excel spreadsheet) showing the forecast electricity prices for avoided electricity costs.

(f) Please describe the basis used by Enbridge to forecast electricity prices for the purposes of avoided electricity costs.

(g) Please describe the degree to which and why avoided gas costs in the TRC calculations differ from the rates appearing on customer bills. Please compare the avoided gas costs with the rates from a typical bill.

(h) Please describe the degree to which and why avoided electricity costs in the TRC calculations differ from the rates appearing on customer bills. Please compare the avoided gas costs with the rates from a typical bill.

(i) With respect to electricity price forecasts and avoided costs: (i) Does Enbridge differentiate between peak and off-peak times? (ii) Does Enbridge differentiate between energy ($/kWh) and capacity costs ($/kW)? For each, please explain the rationale.

(j) If a measure would decrease gas consumption but cause somewhat of an increase in electricity consumption (e.g. a custom commercial or industrial project), how would Enbridge calculate the cost impact of the increased electricity consumption (e.g. for cost-effectiveness calculations or otherwise)? Would Enbridge use the same electricity price forecasts for this purpose as it uses to measure the value of electricity consumption reductions (e.g. from more electrically efficient gas furnace blowers)?

Response

a) Please see Attachment 1 for the EGD rate zone 2021 avoided cost workbook. Please see Attachment 2 for the Union rate zones 2021 avoided cost workbook.

   Within the "Avoided DS Infrastructure" tab in Attachment 1, an Avoided Distribution Cost study is referenced. This study is provided at Attachment 3.

   Within the "Avoided DS Infrastructure" tab in Attachment 2, an Avoided Local Distribution System Infrastructure Costs study is referenced. This study is provided at Attachment 4.

b) Please refer to "Summary of Updates" tabs in Attachment 1 and Attachment 2.

c) Please refer to "Avoided Carbon" tabs in Attachment 1 and Attachment 2.

d) Federal Carbon Charge projections provided by the federal government end in 2030. For avoided carbon costs for 2031 and beyond, as there is no specified federal price beyond this date, Enbridge Gas increased the 2030 avoided carbon costs annually by inflation. The inflation rate used follows the description outlined at Exhibit C, Tab 1, Schedule 1, page 48, section 11.1, which was 2.0% for the 2021 avoided costs.

e) Please refer to "Avoided Electricity" tabs in Attachment 1 and Attachment 2.

f) First year avoided electricity costs are based on the IESO's year-to-date weighted average wholesale rate. For the 2021 avoided costs specifically (as shown at Exhibit E, Tab 5, Schedule 1, Attachment 3, page 2), the rate used is from the IESO October 2020 Monthly Market Report, generated in December 2020. Avoided electricity costs are increased by inflation annually (including for the first year). The inflation rate of 2.0% used for the avoided costs filed in the evidence follows the description outlined at Exhibit C, Tab 1, Schedule 1, page 48, section 11.1.

g) Benefits for the TRC-Plus calculation are based on the avoided cost of not producing and delivering the next unit of a resource (i.e. the marginal throughput-variable cost). Rates on a customer bill will differ as they are the costs from the customer perspective, and are not the necessarily the marginal cost to the system.

   By way of example, the 2021 first year baseload avoided gas cost used for TRC-Plus purposes are:

   - \$0.148 per m^3 for the EGD rate zone (Exhibit E, Tab 5, Schedule 1, Attachment 3, page 2); and
   - \$0.130 per m^3 for the Union rate zones (Exhibit E, Tab 5, Schedule 1, Attachment 3, page 4).

The 2021 average volumetric unit rate for a typical residential customer (including commodity and delivery charges but excluding the Federal Carbon Charge) are:

- \$0.24 per m^3 for a Rate 1 customer in the EGD rate zone
- \$0.20 per m^3 for a Rate M1 customer in the Union South rate zone
- \$0.30 per m^3 for a Rate 01 customer in the Union North rate zone

Please see response to Exhibit I.5.EGI.ED.12, Attachment 1 for further details.

h) See response to part g) for why avoided costs in TRC-Plus calculations differ from the rates appearing on customer bills. However, as discussed in parts f) and i), Enbridge Gas's electricity avoided costs are not developed by the utility and are established in a simplified manner to avoid burdensome complexity.
By way of example, the 2021 first year avoided electricity cost used for TRC-Plus purposes is \$0.151 per kWh for both the EGD rate zone (Exhibit E, Tab 5, Schedule 1, Attachment 3, page 2) and the Union rate zones (Exhibit E, Tab 5, Schedule 1, Attachment 3, page 4).

A typical residential bill is much more complex than just kWh. For example, customers currently have an option to choose time of use ("TOU") or Tiered rates and these vary winter to summer. For the current winter rates, TOU off-peak rates are \$0.082/kWh, mid-peak are \$0.113/kWh and on-peak are \$0.17/kWh while tiered rates are \$0.098/kWh for up to 1,000 kWh and \$0.115/kWh for more than 1,000 kWh. In addition, there are changes by each local LDC. For example, Toronto Hydro residential rates also contain, delivery changes, regulatory charges and additional changes. Some of these components are fixed charges and some are variable by kWh.

i) Enbridge Gas uses annual electricity savings (kWh) for its TRC calculations, rather than peak and off-peak savings or capacity cost savings (kW).

Electricity savings contribute approximately 10% to Enbridge Gas's total TRC benefits. Differentiating between peak and off-peak electricity savings and incorporating capacity savings would add complexity to both the development of avoided electricity cost assumptions and the estimation of electricity savings. Adding this level of complexity is not expected to materially impact the cost effectiveness of Enbridge Gas's DSM offerings and programs.

j) Confirmed. In this scenario, Enbridge Gas would calculate increased electricity costs over the lifetime of the measure in the same way it would calculate avoided electricity costs, but the value would be negative and would appear as a negative benefit in cost effectiveness calculations. The same avoided electricity cost table would be used regardless of whether electricity consumption increases or is reduced.

2021 Avoided Costs - EGD Rate Zone (updated Mar 22, 2021)

Inflation Factor	2.00%
Discount Rate	6.08%

Gas Avoided Costs ($/m3)				
	Baseload		Weather Sensitive	
Year	Rate	NPV	Rate	NPV
2021	0.148	0.148	0.160	0.160
2022	0.178	0.316	0.197	0.346
2023	0.160	0.458	0.190	0.515
2024	0.152	0.585	0.182	0.668
2025	0.185	0.731	0.216	0.838
2026	0.187	0.870	0.219	1.002
2027	0.186	1.001	0.219	1.155
2028	0.203	1.135	0.236	1.312
2029	0.211	1.266	0.245	1.464
2030	0.220	1.395	0.255	1.614
2031	0.240	1.529	0.276	1.767
2032	0.253	1.661	0.290	1.918
2033	0.261	1.790	0.298	2.065
2034	0.282	1.921	0.320	2.213
2035	0.286	2.046	0.324	2.355
2036	0.275	2.159	0.314	2.485
2037	0.299	2.275	0.339	2.617
2038	0.332	2.397	0.372	2.753
2039	0.337	2.513	0.378	2.884
2040	0.340	2.624	0.382	3.008
2041	0.342	2.729	0.386	3.127
2042	0.328	2.824	0.372	3.235
2043	0.336	2.916	0.381	3.339
2044	0.366	3.010	0.412	3.445
2045	0.398	3.107	0.445	3.553
2046	0.413	3.201	0.461	3.658
2047	0.429	3.293	0.478	3.761
2048	0.445	3.384	0.495	3.862
2049	0.462	3.472	0.513	3.960
2050	0.480	3.559	0.532	4.056

Avoided Carbon Costs ($/m3)		
Year	Rate	NPV
2021	0.078	0.078
2022	0.098	0.171
2023	0.127	0.284
2024	0.157	0.415
2025	0.186	0.562
2026	0.216	0.722
2027	0.245	0.894
2028	0.274	1.076
2029	0.304	1.265
2030	0.333	1.461
2031	0.340	1.649
2032	0.347	1.830
2033	0.353	2.004
2034	0.361	2.172
2035	0.368	2.333
2036	0.375	2.488
2037	0.383	2.636
2038	0.390	2.779
2039	0.398	2.917
2040	0.406	3.049
2041	0.414	3.177
2042	0.422	3.299
2043	0.431	3.416
2044	0.440	3.530
2045	0.448	3.638
2046	0.457	3.743
2047	0.466	3.843
2048	0.476	3.940
2049	0.485	4.033
2050	0.495	4.122

Water Avoided Costs ($/m3)		
Year	Rate	NPV
2021	0.994	0.994
2022	1.014	1.950
2023	1.034	2.869
2024	1.055	3.753
2025	1.076	4.603
2026	1.098	5.420
2027	1.120	6.206
2028	1.142	6.962
2029	1.165	7.688
2030	1.188	8.387
2031	1.212	9.058
2032	1.236	9.704
2033	1.261	10.325
2034	1.286	10.922
2035	1.312	11.496
2036	1.338	12.048
2037	1.365	12.579
2038	1.392	13.090
2039	1.420	13.580
2040	1.448	14.052
2041	1.477	14.506
2042	1.507	14.942
2043	1.537	15.362
2044	1.568	15.765
2045	1.599	16.153
2046	1.631	16.526
2047	1.664	16.885
2048	1.697	17.229
2049	1.731	17.561
30	1.766	17.880

Electricity Avoided Costs ($/KWh)		
Year	Rate	NPV
2021	0.151	0.151
2022	0.154	0.296
2023	0.157	0.435
2024	0.160	0.569
2025	0.163	0.698
2026	0.167	0.822
2027	0.170	0.941
2028	0.173	1.056
2029	0.177	1.166
2030	0.180	1.272
2031	0.184	1.374
2032	0.188	1.472
2033	0.191	1.566
2034	0.195	1.657
2035	0.199	1.744
2036	0.203	1.828
2037	0.207	1.908
2038	0.211	1.985
2039	0.215	2.060
2040	0.220	2.131
2041	0.224	2.200
2042	0.229	2.267
2043	0.233	2.330
2044	0.238	2.391
2045	0.243	2.450
2046	0.247	2.507
2047	0.252	2.561
2048	0.257	2.613
2049	0.263	2.664
2050	0.268	2.712

Notes:
1- Non-energy Benefits Adder is not added in the avoided costs. Its needs to be incorporated into TRC-Plus calculation.
2- For actual cost effectiveness tests, Avoided Carbon costs are weighted based on Rate Class (as show in the Table A below) of the customer.
3- For forecasting cost effectiveness, Avoided Carbon costs are weighted based on Market Segment (as show in the Table B below) of the customer.

Table A	
Rate Class	% Subject to Carbon Charge
1	100.0%
6	96.3%
9	-
100	59.1%
110	74.2%
115	9.4%
125	0.0%
135	100.0%
145	75.0%
170	21.6%
200	0.0%
300	0.0%

Table B			
Market Segment for Forecasting	Weighted % Subject to Carbon Charge	% Subject to Carbon Charge Min	% Subject to Carbon Charge Max
Residential	100.0%	100.0%	100.0%
Commercial/Industrial	83.9%	9.4%	100.0%

Year one of the Avoided Costs table	2021	
Inflation Factor	2.00%	GDP IPI FDD four quarter moving average updated Sep 2, 2020
Discount Rate	6.08%	
U.S. $ to Canadian $ Exchange Rate	1.3	Exchange rate provided by Financial Forecasting Group
GJ/m3 Natural Gas Conversion Factor	0.03888	Heat rate provided by Gas Supply
MMBtu/m3 Natural Gas Conversion Factor	0.03685	

Summary of Updates	
Avoided Cost Component	**Updated**
Inflation Factor	Sep 2020
SENDOUT Report	Mar 2021
ICF Natural Gas Strategic Prices	Q3 2020
Avoided Downstream Infrastructure Costs	Various, last update Dec 2020
Avoided Unaccounted for Fuel Losses	Dec 2020
Aoided Cost of Carbon	Mar 2021
Water Avoided Costs	Dec 2020
Electricity Avoided Costs	Dec 2020

DSM Voulmes - 2018 Post-Audit Results	
Load Type	Net Annual Natural Gas Savings (m3)
Weather Sensitive (Space Heating)	26,751,126
Baseload (Water Heating and Industrial)	15,637,442
Total	42,388,568

SENDOUT Report				
		Volumes and Total Costs, 2021 - 2023		
Next Generation Version				
		Col. 1	Col. 2	Col. 3
Item No.		2021	2022	2023
	Base Case			
1	Demand (10 6 m3)	12,163	12,201	12,232
2	Total Cost ($000)	1,492,033	1,760,983	1,702,908
3	Average Cost ($/10 3m3)			
	Seasonal Cost ($/103m3)	123	144	139
	Decrement in Baseload			
4	Demand Reduction (10 6 m3)	16	16	16
5	Total Cost ($000)	1,489,791	1,758,267	1,700,479
6	Unit Avoided Gas Cost ($/10 3m3)			
	Unit Avoided Seasonal Gas Cost ($/103m3)	143	174	155
	Decrement in Weather Sensitive			
7	Demand Reduction (10 6 m3)	27	27	27
8	Total Cost ($000)	1,488,181	1,756,150	1,698,260
9	Unit Avoided Gas Cost ($/10 3m3)			
	Unit Avoided Seasonal Gas Cost ($/103m3)	144	181	174

Updated March 2021

Avoided Gas Commodity, and Upstream Transmission/Storage Costs		
Year	Base Load $/m3	Weather Sensitive $/m3
2021	0.143	0.144
2022	0.174	0.181
2023	0.155	0.174
2024	0.147	0.166
2025	0.180	0.199
2026	0.182	0.202
2027	0.181	0.201
2028	0.198	0.218
2029	0.205	0.226
2030	0.214	0.236
2031	0.235	0.256
2032	0.248	0.270
2033	0.255	0.278
2034	0.276	0.299
2035	0.280	0.303
2036	0.268	0.292
2037	0.292	0.317
2038	0.325	0.350
2039	0.330	0.355
2040	0.333	0.359
2041	0.336	0.362
2042	0.321	0.348
2043	0.329	0.356
2044	0.359	0.387
2045	0.390	0.419
2046	0.405	0.434
2047	0.421	0.451
2048	0.437	0.467
2049	0.454	0.485
2050	0.472	0.503
Sendout gas costs adjusted by inflation and ICF Q3 2020 Natural Gas Strategic Gas Prices beyond year 2023		

Levelized Distribution Cost for Baseload $/m3[1]	0.00379	Avoided Distribution Costs by Navigant dated Dec 2015 p. 26
Levelized Distribution Cost for Weather Sensitive $/m3[1]	0.01396	Avoided Distribution Costs by Navigant dated Dec 2015 p. 26
Year of Study	2015	
Avoided Seasonal Storage Costs at Dawn for Baseload $/GJ	-	
Avoided Seasonal Storage Costs at Dawn for Weather Sensitive $/GJ	-	
Year of Study	-	

Avoided Downstream Infrastructure Costs

	Distribution		**Seasonal Storage at Dawn**	
Year	Baseload $/m3	Weather Sensitive $/m3	Baseload $/m3	Weather Sensitive $/m3
2021	0.004	0.016	-	-
2022	0.004	0.016	-	-
2023	0.004	0.016	-	-
2024	0.005	0.017	-	-
2025	0.005	0.017	-	-
2026	0.005	0.017	-	-
2027	0.005	0.018	-	-
2028	0.005	0.018	-	-
2029	0.005	0.018	-	-
2030	0.005	0.019	-	-
2031	0.005	0.019	-	-
2032	0.005	0.020	-	-
2033	0.005	0.020	-	-
2034	0.006	0.020	-	-
2035	0.006	0.021	-	-
2036	0.006	0.021	-	-
2037	0.006	0.022	-	-
2038	0.006	0.022	-	-
2039	0.006	0.022	-	-
2040	0.006	0.023	-	-
2041	0.006	0.023	-	-
2042	0.006	0.024	-	-
2043	0.007	0.024	-	-
2044	0.007	0.025	-	-
2045	0.007	0.025	-	-
2046	0.007	0.026	-	-
2047	0.007	0.026	-	-
2048	0.007	0.027	-	-
2049	0.007	0.027	-	-
2050	0.008	0.028	-	-

Update Dec 2020

[1] The derivation of the avoided distribution costs is based on a proprietary model

Unaccounted for Fuel Loss Rate		0.162%

UG rate zone number is used for EGD rate zone as well. This rate is updated in each years annual rates application. The rate for 2020, 0.162%, was approved in EB-2019-0194 Decision and Order, Dec. 5, 2019.

Avoided Unaccounted for Fuel Losses		
	Baseload	Weather Sensitive
Year	$/m3	$/m3
2021	0.00023	0.00023
2022	0.00028	0.00029
2023	0.00025	0.00028
2024	0.00024	0.00027
2025	0.00029	0.00032
2026	0.00029	0.00033
2027	0.00029	0.00033
2028	0.00032	0.00035
2029	0.00033	0.00037
2030	0.00035	0.00038
2031	0.00038	0.00042
2032	0.00040	0.00044
2033	0.00041	0.00045
2034	0.00045	0.00048
2035	0.00045	0.00049
2036	0.00043	0.00047
2037	0.00047	0.00051
2038	0.00053	0.00057
2039	0.00053	0.00058
2040	0.00054	0.00058
2041	0.00054	0.00059
2042	0.00052	0.00056
2043	0.00053	0.00058
2044	0.00058	0.00063
2045	0.00063	0.00068
2046	0.00066	0.00070
2047	0.00068	0.00073
2048	0.00071	0.00076
2049	0.00074	0.00079
2050	0.00076	0.00082

Updated Dec 2020

Aoided Cost of Carbon		
Year	$/tCO2e	Cost of Carbon ($/m3)
2021	40	0.078
2022	50	0.098
2023	65	0.127
2024	80	0.157
2025	95	0.186
2026	110	0.216
2027	125	0.245
2028	140	0.274
2029	155	0.304
2030	170	0.333
2031	173	0.340
2032	177	0.347
2033	180	0.353
2034	184	0.361
2035	188	0.368
2036	191	0.375
2037	195	0.383
2038	199	0.390
2039	203	0.398
2040	207	0.406
2041	211	0.414
2042	216	0.422
2043	220	0.431
2044	224	0.440
2045	229	0.448
2046	233	0.457
2047	238	0.466
2048	243	0.476
2049	248	0.485
2050	253	0.495

Assumptions:
1-No change in conversion from $/tCO2e to cents/m3 from 2019-2022 to 2023-2030
2- Increase in cost of carbon beyond 2030 as per inflation
3-Weighted application of carbon price across Res/Com and Ind sectors

Updated March 2021

https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html

https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html

Filed: 2020-12-08
EB-2020-0212
Exhibit I.EP.3
Attachment 1
Page 1 of 2

Enbridge Gas Inc.
EGD Rate Zone
Updated Exhibit B, Tab 1, Schedule 1
2021 Customer-Related Volumes by Rate Class (April 2021 to March 2022)
(10^3m^3)

Line No.	Rate Class	Col. 1 Forecast Volumes[1]	Col. 2 OBPS Particip ant & Other Exempt Volume s[2]	Col. 3 (Col. 1 - Col. 2) Net Volumes	% subject to Carbon Charge
1	1	5,116,256	455	5,115,801	100%
2	6	4,903,468	#####	4,723,930	96%
3	9	-	-	-	
4	100	33,431	#####	19,771	59%
5	110	957,019	#####	709,936	74%
6	115	469,919	#####	44,317	9%
7	125[3]	560,000	#####	-	0%
8	135	61,643	-	61,643	100%
9	145	27,157	6,780	20,377	75%
10	170	267,329	#####	57,638	22%
11	200[4]	181,853	#####	-	0%
12	300	-	-	-	
13	Total Customer-Related	12,578,074	######	10,753,413	

Notes:
(1) Forecast Volumes after DSM from April 1, 2021 to March 31, 2022.
(2) Estimated forecast volumes for mandatory and voluntary participants in the Output Based Pricing System (OBPS), volumes qualifying for exemption for non-covered activities and partial relief (80%) for greenhouse operators.
(3) Dedicated unbundled customers.
(4) Includes volumes delivered to downstream distributors and landfill gas.

Rate Class for Forecasting		
	Residential	Commercial/Industrial
	1	
		6
		100
		110
		115
		135
		145
		170
Weighted % Subject to Carbon Charge	100.0%	83.9%
Min	100.0%	9.4%
Max	100.0%	100.0%

Step 1 - Update the population in each sample municipality and calculate their relative within each region
Population is based on the 2016 Census

		Population	Regional Total Population	Weighting within each region
Niagara	Niagara Falls	88,071	221,184	40%
	St. Catherines	133,113		60%
York	Richmond Hill	195,022	830,221	23%
	Vaughan	306,233		37%
	Markham	328,966		40%
Toronto	Toronto	2,731,571	2,731,571	100%
Ottawa	Ottawa	934,243	934,243	100%
	Total	4,717,219		

Tip: Confirm the above municipalities represent the majority of the population in each region.

Step 2 - Determine the retail rates for water and waste water in each municipality
Note: Many municipalities only repoort the combined retail rate, rather than separate rates for water and waste water

		EXAMPLE: 2020		
		Water ($ / 1000 l)	Waste Water ($ / 1000 l)	Combined Rate
Niagara	Niagara Falls	1.104	1.2280	2.3320
	St. Catharines	1.352	2.0050	3.3570
York	Richmond Hill	n/a	n/a	4.7424
	Vaughan	2.0725	2.4957	4.5682
	Markham	n/a	n/a	4.4680
Toronto	Toronto	n/a	n/a	4.0735
Ottawa	Ottawa - Tier 1	0.83	0.75	1.5800
	Ottawa - Tier 2	1.65	1.49	3.1400
	Ottawa - Tier 3	1.82	1.65	3.4700
	Ottawa - Tier 4	2.03	1.85	3.8800

	Regional Retail Rate	Discounted by a Factor of 4	Regional Weighting	Avoided Cost by Region Weight
Niagara	2.95	0.74	5%	0.03
York	4.57	1.14	18%	0.20
Toronto	4.07	1.02	58%	0.59
Ottawa	3.02	0.75	20%	0.15

Avoided Cost of Water $/m3	0.974727

Avoided water rate is calculated by discounting retail rate to 25% based on 2015 audit finding.

Ottawa has a new tiered system for water rates as of 2019. The rate includs water and wastewater together.
Tier 1 - 0 to 6^{m3}
Tier 2 - 6^{m3} to 25^{m3}
Tier 3 - 25^{m3} to 180^{m3}
Tier 4 - 180^{m3}

Water Avoided Costs	
Year	$/m3
2021	0.994
2022	1.014
2023	1.034
2024	1.055
2025	1.076
2026	1.098
2027	1.120
2028	1.142
2029	1.165
2030	1.188
2031	1.212
2032	1.236
2033	1.261
2034	1.286
2035	1.312
2036	1.338
2037	1.365
2038	1.392
2039	1.420
2040	1.448
2041	1.477
2042	1.507
2043	1.537
2044	1.568
2045	1.599
2046	1.631
2047	1.664
2048	1.697
2049	1.731
2050	1.766

Updated December 2020

IESO Wholesale Weighted Average Year to Date Rate $/MWh	147.85

IESO Monthly Market Report October 2020, accessed Dec 2020

Electricity Avoided Costs	
Year	$/KWh
2021	0.151
2022	0.154
2023	0.157
2024	0.160
2025	0.163
2026	0.167
2027	0.170
2028	0.173
2029	0.177
2030	0.180
2031	0.184
2032	0.188
2033	0.191
2034	0.195
2035	0.199
2036	0.203
2037	0.207
2038	0.211
2039	0.215
2040	0.220
2041	0.224
2042	0.229
2043	0.233
2044	0.238
2045	0.243
2046	0.247
2047	0.252
2048	0.257
2049	0.263
2050	0.268

Updated Dec 2020

Table A: Time-of-Use Definitions

Avoided energy costs are grouped into eight Time-of-Use (TOU) periods to reflect the diurnal and seasonal fluctuations. Time-of-use periods are Hour Starting to Hour Ending (e.g. 0700 – 1100 is a 4-hour period, starting at 7am and ending at 11am).

Table A1: Time-of-Use Seasons

Season	Months Included
Winter	December – March
Summer	June – September
Shoulder	April, May, October & November

Table A2: Time-of-Use Period Definitions

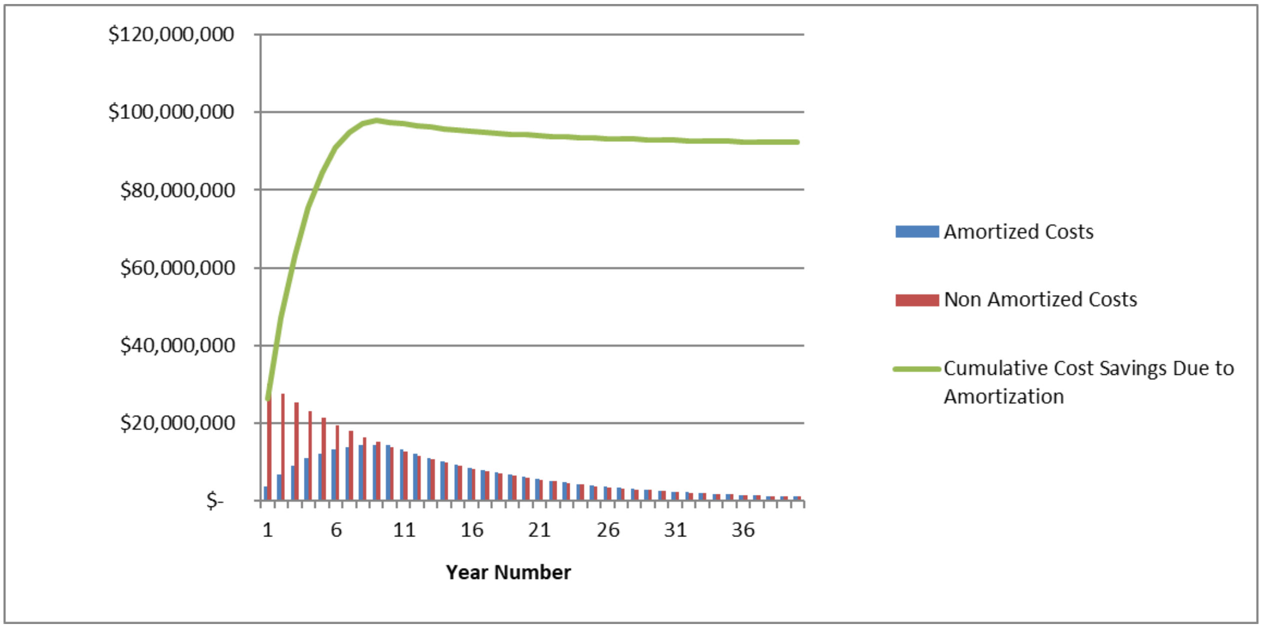
	Winter (December – March)	**Summer** (June – September)	**Shoulder** (April, May, October, November)
On-Peak	0700 – 1100 and 1700 – 2000 weekdays (602 Hours)	1100 – 1700 weekdays (522 hours)	*None*
Mid-Peak	1100 – 1700 and 2000 – 2200 weekdays (688 hours)	0700 – 1100 and 1700 – 2200 weekdays (783 hours)	0700 – 2200 weekdays (1,305 hours)
Off-Peak	0000 – 0700 and 2200 – 0000 weekdays; All hours weekends and holidays (1,614 hours)	0000 – 0700 and 2200 – 0000 weekdays; All hours weekends and holidays (1,623 hours)	0000 – 0700 and 2200 – 0000 weekdays; All hours weekends and holidays (1,623 hours)

Note: Number of hours represent the daily hours for the various periods

Table 1: 2020 Avoided Costs (2020 Dollars)

Year	2020 Avoided Energy Cost by Season and Time-of-Use Period (2020$/MWh)									2020 Avoided Capacity Costs (2019$/kW-mth) Generation	
	Winter On Peak	Winter Mid-Peak	Winter Off-Peak	Summer On Peak	Summer Mid-Peak	Summer Off-Peak	Shoulder Mid-Peak	Shoulder Off Peak	Annual	Summer (May 1 to October 31)	Winter (November 1 to April 30)
2021	$21	$20	$24	$27	$25	$28	$18	$21	$23	$0	
2022	$25	$22	$23	$29	$29	$21	$24	$17	$23	$3	$0
2023	$35	$33	$29	$30	$30	$30	$27	$22	$29	$8	$8
2024	$31	$30	$28	$30	$29	$22	$27	$27	$27	$6	$0
2025	$36	$33	$30	$32	$33	$23	$27	$23	$28	$10	$5
2026	$41	$40	$34	$43	$38	$29	$29	$25	$33	$10	$10
2027	$42	$37	$35	$37	$37	$30	$29	$24	$32	$10	$9
2028	$42	$36	$31	$39	$39	$31	$30	$28	$33	$9	$10
2029	$48	$40	$33	$37	$38	$30	$28	$25	$33	$10	$9
2030	$44	$36	$33	$57	$49	$31	$32	$28	$36	$10	$9
2031	$54	$41	$34	$43	$39	$31	$32	$29	$36	$10	$9
2032	$51	$40	$34	$41	$41	$30	$30	$25	$34	$10	$10
2033	$49	$41	$35	$40	$41	$30	$31	$27	$35	$11	$8
2034	$46	$40	$34	$47	$44	$32	$30	$22	$34	$10	$10
2035	$49	$39	$33	$50	$59	$36	$31	$25	$37	$10	$9
2036	$52	$40	$35	$53	$57	$37	$30	$26	$38	$10	$9
2037	$57	$46	$38	$49	$51	$36	$31	$25	$39	$10	$9
2038	$55	$45	$39	$59	$58	$38	$35	$26	$41	$10	$10
2039	$60	$47	$42	$59	$66	$39	$34	$31	$44	$10	$8
2040	$70	$51	$43	$67	$74	$41	$36	$28	$47	$10	$8

Table E1: Cumulative Cost Savings from Amortization – 10% Discount Rate, 4% Interest Rate



We also examine cost recovery approaches in Maryland, Illinois, New Jersey, New York, Utah, Delaware and Missouri and discuss the approach to amortizing energy efficiency expenses, highlighting varying amortization periods and interest rates.

In Enbridge's interrogatory responses, they indicate that based on their interpretation of the OEB's December 1, 2020 guidance that indicated "the OEB anticipates modest budget increases to be proposed by Enbridge in the near-term…", that amortization is likely not necessary. While this position seems reasonable if budgets are staying relatively flat, amortization could be appropriate for Ontario in the future as a way to fund an expansion in efficiency efforts while minimizing rate impacts.

When considering what cost recovery model to use, it is important to properly value the costs in the near and long-term. This is why it is important to use a net present value approach that applies a reasonable discount rate to efficiency costs so that they are appropriately valued in the analysis informing the decision of what cost recovery model is most appropriate. Based on the OEB's findings regarding what cost recovery model to use, we recommend that a single cost recovery approach (amortization or full annual cost recovery) should be used for all programs and sectors to avoid the complexity involved in using different approaches for different programs.

Optimal recommends considering the following factors should amortization of natural gas conservation costs be implemented in Ontario:

- **Amortization Consideration 1: Interest rate** – the selected interest rate can have a large impact on the success of amortization and should be set at a low rate, such as the utility's cost of debt. Interest rates used in jurisdictions with amortization range from the utility rate of return in Maryland, to the ~~short-term carrying cost of debt~~ weighted average cost of capital, used in ~~Missouri~~ Utah. While using the rate of return will align demand side spending most closely with supply side spending, it also rewards utility spending, as opposed to the performance of the programs, which does not provide the proper incentives. Further, the average rate of return for US utilities is over 10%,[1] which is significantly greater than what is shown necessary to incent utilities for efficiency spending. We therefore recommend that the interest rate be set at the utility carrying costs~~.~~ This approach effectively removes any shareholder profit on the amortization but ensures the utility is made whole on its costs and allows for earnings to be tied more directly to performance.

- **Amortization Consideration 2: Loan term** – the loan term should be set in a straightforward manner and ideally align program costs with program benefits. We suggest using the same loan term for all programs and sectors and basing it on a fixed number of years, approximately representing the average measure life of a typical efficiency portfolio. However, a shorter loan term could function as a good compromise between those stakeholders who want amortization and those that worry about increased interest payments and the optics of nominal SBC rates that are higher with continuous program investment that has occurred for longer than the loan term. Illinois, for example, uses the weighted average measure life of the entire portfolio savings.
- **Amortization Consideration 3: Performance Incentive** – as discussed in greater detail below amortization approaches can combine cost recovery and performance incentives. However, we do not recommend this approach. Rather, we suggest approaching the performance incentive separately from the cost recovery approach, as is currently done in Ontario. This eliminates compounding performance earnings and higher costs to ratepayers.
- **Amortization Consideration 4: Lost Revenues** – these are recurring annual expenses and should not be amortized with program costs. We suggest continuing the current practice in Ontario and allowing for annually recovery and incorporating into future forecasts.

Performance Incentives

In this section, we discuss best practices for performance incentive (PI) design, including that they be multi-variate, scalable, and performance based, and get into considerations on how to choose specific incentive structures and metrics. We also perform a survey of PIs in other jurisdictions, looking at the target amount, threshold amount, cap, and how the PI is calculated in general. We look with greater detail at the mechanisms used in New York, Illinois, and Massachusetts, as these states all have high performing efficiency programs but calculate the performance incentives very differently.

Finally, we describe Enbridge Gas's proposed approach to the performance period for the 2023-2027 plan. Enbridge Gas's approach is fairly complicated, and includes separate calculations

[1] https://blog.aee.net/how-do-electric-utilities-make-money

Implementation Details

Interest Rate

The interest rate that the utility will get from the amortized program cost repayments can have a large impact on utility revenue requirements of amortization compared to typical cost recovery. Interest rates used in jurisdictions with amortization range from the utility rate of return in Maryland, to the ~~short-term carrying cost of debt~~ weighted average cost of capital, used in ~~Missouri~~ Utah. While using the rate of return will align demand side spending most closely with supply side spending, it also rewards utility spending, as opposed to the performance of the programs. As discussed in the Performance Incentive Chapter, we do not believe this creates the proper incentives for utilities and would thus recommend the interest rate set at the utility carrying costs for borrowing money~~, or the short-term carrying cost of debt~~ over the relevant loan term. Further, the average rate of return for US utilities is over 10%,[9] which is significantly greater than what is shown necessary to incent utilities for efficiency spending. Further, using a rate of return interest rate may create a backlash against efficiency when, after many years of program activity, costs to ratepayers appear higher than they would be without amortization (even though they may be lower on a present value basis). In fact, this is indeed happening in Maryland, and groups of stakeholders are pushing to change the cost recovery model back to standard model.[10] Maryland programs are discussed in more detail below.

Loan Term

The loan term also has impacts on program cost recovery. In current amortization models, we see loan terms varying between a straight five (5) years and the weighted average measure life of the programs. In theory, any loan term could be accommodated, and there could even be different loan terms by program and/or sector. In general, as the loan term shortens, the rate and revenue impacts will start to converge on those for annual cost recovery. We recommend using a single loan term approximately equal to the weighted average measure life of the programs, as this will best align the costs of efficiency with their associated benefits while avoiding unnecessary complexity. However, a shorter loan term could function as a good compromise between those stakeholders who want amortization and those that worry about increased interest payments and the optics of nominal SBC rates that are higher with continuous program investment that has occurred for longer than the loan term. ~~Missouri, for example, uses a loan term of five (5) years~~. Illinois, for example, uses the weighted average measure life of the entire portfolio savings.

Potential Linkages or Integration of Shareholder Incentives and Amortization

There are several potential linkages between amortization and the structure of the shareholder incentive that can be used. In particular, amortization can enable an incentive that is similar to the rate of return a utility earns on rate-based assets in which good energy efficiency performance is rewarded through an increase or decrease in the allowed rate of return for the amortized program expenses, as is used in Illinois and New Jersey. This type of performance incentive will be discussed more in the next section. It essentially allows for both amortized cost recovery and a performance incentive all in a single cost recovery approach. For example, Illinois

[9] https://blog.aee.net/how-do-electric-utilities-make-money

[10] Interview with David Hill, Managing Consultant, Energy Futures Group.

Jurisdictions Using Amortization

While most jurisdictions use a standard full annual cost recovery approach, there are a few jurisdictions that do currently amortize efficiency program costs. The table below shows a summary of key aspects of the amortization implementation. In some cases, such as in Illinois, the legislation mandated that program expenses could be amortized[15]. In others, such as Maryland, it was a decision by the relevant regulatory agency[16].

Table 5: Summary of Jurisdictions Using Amortization for Cost Recovery

Jurisdiction	2018 Savings (% of load)	Loan Term	Interest Rate	Performance Incentive Type
Maryland	0.31%	5 years	Approved Rate of Return (~10%)	None
Illinois (electric only)[17]	2.3%	Weighted Average Measure Life	Approved rate of return plus or minus up to 200 basis points depending on performance[18]	Integrated with cost recovery. Increase/decrease rate of return up to a max of 200 basis points
New Jersey	Ramping up to all cost-effective efficiency	10 years	Approved Rate (return on equity minus 100 basis points) of Return plus or minus up to 50 basis points depending on performance	Integrated with cost recovery. Increase/decrease rate of return up to a max of 50 basis points
New York	0.68%	10 years	Rate of Return	Increase rate of return up to a max of 100 basis points
Utah[19]	0.71%	10 years	Weighted Average Cost of Capital	None
Delaware	0.38%	5 years	Approved Rate of Return (9.7%)	None
Missouri ~~(electric only)~~[20]	0.61%	6~~5~~ years[21]	~~Short term cost of debt (currently approximately 1.5%)~~ Gas Utilities recover program costs at the rate of return. Electric shifted away from	Performance earnings are separate awards for various savings and other metrics[22].

[15] See: https://www.ilga.gov/legislation/ilcs/ilcs4.asp?DocName=022000050HArt.+VIII&ActID=1277&ChapterID=23&SeqStart=9900000&SeqEnd=14800000

[16] See: https://www.bpu.state.nj.us/bpu/pdf/boardorders/2020/20200610/6-10-20-8D.pdf

[17] IL only has PIs for electric utilities. While both state electric IOU's have analogous PI mechanisms, this describes the PI details for Commonwealth Edison, which serves the majority of the State load. There are a few variations in threshold levels and savings depth for Ameren Illinois.

[18] This type of incentive is achieved by increasing the interest rate the utilities receive on program expenditures if the program meets certain performance hurdles and/or decreasing the interest rates if performance is unsatisfactory.

[19] See: https://le.utah.gov/~2020/bills/hbillint/HB0326.htm

[20] Missouri only has PIs for electric utilities.

[21] This applies to the electric earnings opportunity, which is amortized over a 2-year period, but given three year goals, earnings do not begin until year 4 (since it takes ~1 year for EM&V results). This means that there is effectively a 6-year period before the EO is fully paid off. This is capitalized using the short-term cost of debt. See KCP&L's 2016-2018 MEEIA Plan, page 57, for more information on how this works: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935953627

[22] Missouri only has PIs for electric utilities.

Jurisdiction	2018 Savings (% of load)	Loan Term	Interest Rate	Performance Incentive Type
			amortizing program costs around 2016, but PIs are recovered over approximately 6 years and accrue interest at the utility short term cost of debt.	

Maryland Experience

While many of the jurisdictions listed above have only implemented amortization recently, Maryland has been amortizing efficiency program costs since 2008. Given the 5-year amortization period in the state, this means that Maryland is at the point where nominal SBCs are higher than they would be under a non-amortized cost recovery scheme. Given the relatively high interest rate (the utilities' approved rate of return), this difference is now fairly significant.

In response, some stakeholders are attempting to lower the interest rate given to the amortized program expenses and/or phase out amortization in favor of a more traditional annual expensing of program expenses. The Maryland Office of People's Counsel (OPC), while acknowledging amortization played an important role in allowing the initial steep ramp up period of Maryland efficiency programs, maintains that now that program costs are steady from year-to-year, the utilities do not have to raise capital from market sources to fund them, and so now would make more sense to be treated as a pass-through cost with full annual recovery. They advocate lowering the interest rate to the utility's actual cost of debt, which should be low given the high certainty of recovery, while at the same time transitioning away from amortizing the program expenses. Commission staff has a similar position, arguing for an interest rate set at a 5-year treasury bill along with a slightly slower transition towards full annual cost recovery[23].

The Maryland experience underlines certain dangers in the amortization approach, as well as the importance of setting the loan term and interest rate in a manner that covers the utility costs without becoming overly burdensome to the ratepayers in the long term. However, even though some stakeholders are advocating for adjustment, the program was not a complete failure. It is generally acknowledged that by limiting short term rate increases, amortization was a significant factor allowing program expansion. Further, other jurisdictions that amortize program expenses, such as New Jersey and Illinois ~~and Missouri~~, have not seen the same issues. We believe that the main issue for Maryland was that the interest rate was set too high, and if the rate were instead set at the price of debt as OPC now advocates, there would not currently be an issue.

COST RECOVERY IN ONTARIO

Current Approach

Ontario currently uses an annual cost recovery approach for its natural gas DSM expenses. In the 2015-2020 DSM Framework, the Ontario Energy Board (OEB), while recognizing the value of energy efficiency, set a maximum rate impact of $2 per month for a typical residential customer,

[23] EmPower Cost Recovery Work Group Report. Case No. 9494. April 15, 2019.

- The decision to move to an amortization structure should be informed by a full consideration of the variables above, but also by properly valuing the costs in the near and long-term. This is why it is important to use a net present value approach that applies a reasonable discount rate to efficiency costs so that they are appropriately valued in the analysis informing the decision regarding the appropriate cost recovery model.
- Approach the **performance incentive** separately from the cost recovery approach. The terms of amortization should be set to properly compensate the utility for the carrying costs of the related debt, but not to provide a rate of return. This has been done effectively ~~in many jurisdictions~~ with ~~smaller~~ separate and more controllable performance incentives that can be separately set. This eliminates compounding performance earnings over time resulting in higher costs to ratepayers and higher earnings than intended. It also can ensure Ontario more consistency with current and past practice, as discussed in the next section. The specifics of Ontario's current performance incentive are discussed more in the next section.
- **Lost Revenue** is a recurring annual expense and should not be amortized with the program costs. We believe this makes sense because lost revenue is simply redistributing costs that are already in rates and are thus naturally collected on an on-going basis otherwise. In addition, lost revenue balances will zero out every time a rate case happens, so it is better to stay continuously current with LRAM balances.