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Enbridge Gas Inc.
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North York, Ontario
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VIA RESS and EMAIL

January 31, 2022

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

Dear Ms. Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2021-0002
Multi-Year Demand Side Management Plan (2022 to 2027)
Enbridge Gas Reply Evidence

In accordance with the OEB's Procedural Order #6 please find Enbridge Gas's Reply Evidence for its Multi-Year Demand Side Management Plan (2022 to 2027).

The report attached was prepared by Edward M. Weaver of First Tracks Consulting Service Inc. As such Enbridge Gas has also attached Form A, acknowledgement of the expert's duty, as well as his CV as Appendix A.

Should you have any questions on this matter please contact the undersigned at 416-495-5642.

Sincerely,

Asha Patel Digitally signed by Asha Patel
Date: 2022.01.31 16:49:17 -05'00'

Asha Patel
Technical Manager, Regulatory Applications

cc: D. O'Leary, Aird & Berlis
EB-2021-0002 Intervenors

Amortization and Performance Incentives as Business Models for Utility Demand-Side Management Portfolios:

Recommendations for Enbridge Gas

January 31, 2022

First Tracks Consulting Service, Inc.

P.O. Box 1484
Nederland, Colorado 80466

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INTRODUCTION

On September 29, 2021, Enbridge Gas Inc. (Enbridge) filed an updated multi-year demand side management (DSM) plan for years 2023-2027. On December 1, 2021, select intervenors filed expert evidence addressing various aspects of the DSM Plan. Among the evidence were a report from Optimal Energy Inc.[1] (Optimal), filed on behalf of Ontario Energy Board (OEB) Staff and a report from Energy Future Group[2] (EFG), filed on behalf of Green Energy Coalition and Environmental Defence.

My report responds to three issues raised in those reports:

- Use of amortization as a cost recovery mechanism (raised in the Optimal report)
- Proposals for shareholder incentive mechanisms (raised in the Optimal and EFG reports)
- Comparisons of Enbridge savings forecast to benchmarks savings achieved by other utilities (raised in the EFG report)

I address each of these issues in separate sections of this report. I summarize my recommendations for the OEB in this proceeding in Section 1.

This report is authored by Edward Weaver. Mr. Weaver is the President of First Tracks Consulting Service, Inc. He has been active in sustainable energy markets for over 40 years, working for and with utilities and governments in over 40 states, provinces, and territories throughout North America. He has helped clients develop and manage over $7 billion ($C) in demand-side management (DSM) investment, and has helped multiple clients develop and manage amortization and performance incentive mechanisms. He has testified before utility commissions in 18 proceedings. He also advises early-stage clean technology companies, and is a co-founder of one providing methane monitoring services and a minority partner in another providing EV smart charging services.

Enbridge engaged First Tracks to support the utility's understanding of amortization as a cost recovery model for DSM funding, including consideration for performance incentives. Through the submission of expert testimony supporting Enbridge's reply evidence, this report is provided to assist the OEB in considering how these matters might be appropriately employed in Ontario. This engagement, and therefore this report, also included a request to review expert evidence submitted by other parties to this proceeding, and providing context, recommendations, and commentary as appropriate.

I was first engaged by Enbridge in the summer of 2021, and completed most of my work over the autumn and early winter. I was not involved in the original development of Enbridge's portfolio, program designs, or budget allocations, nor was I involved in the original development of the Enbridge performance incentive mechanism. My opinions regarding the performance incentive mechanism and plan are therefore provided as an outside observer; questions regarding the detailed makeup of Enbridge's plan or Enbridge's motivation behind plan or mechanism design should be directed to the Company's own experts in this proceeding.

[1] Exhibit L.OEB STAFF.1
[2] Exhibit L.GEC.ED.1

1. SUMMARY OF RECOMMENDATIONS FOR THE OEB

This section repeats my recommendations for the OEB regarding amortization (covered in Section 2), performance incentives (covered in Section 3), and utility savings benchmarks (covered in Section 4).

1.1. Recommendations Regarding Amortization

1.1.1. Conclusions Regarding General Amortization Calculations

- Under most cases with likely values for key inputs, compared to traditional expense treatment, amortization results in:
  - Lower revenue requirements in the early years.
  - Higher revenue requirements in later years.
  - NPV of revenue requirements identical for both amortization and expense treatment (when using the utility's cost of capital as the discount rate), and equal to the present value of DSM expenditures.
  - Regulatory assets that build up, although the size of the asset depends on levels of spending and the amortization term.
- Shorter asset terms used in amortization calculations (compared to longer terms) result in:
  - Much higher revenue requirements in the short term.
  - Slightly lower revenue requirements in the long term.
  - Revenue requirements that exceed those associated with typical expense treatment more quickly.
  - Much lower unamortized asset balances.
  - Much lower cost of capital charges to customers.
- Higher cost of capital inputs in amortization calculations (compared to lower inputs) result in:
  - Higher revenue requirements in all years, with the difference larger in the early years.
  - Revenue requirements that exceed those associated with typical expense treatment more quickly.
  - Identical unamortized asset balances.
  - Higher cost of capital charges to customers.

1.1.2. Response to Optimal's Overall Conclusion Regarding Amortization

- I agree with Optimal that amortization could allow the OEB to achieve higher DSM budges while maintaining the OEB's historic guidance on rate increases, but only in the short term. In the longer term, amortization drives higher rates, while also creating new concerns around regulatory asset balances.
- I recommend that the OEB address three key questions before moving forward with amortization:
  - What level of budget increases are desired?
  - What amortization structure will the OEB implement, specifically what amortization term and what cost of capital?
  - How should competing policy objectives be balanced, specifically, increases in DSM budgets, short- and long-term rate levels, and acceptable regulatory asset balances.

- If the OEB does approve substantial DSM budget increases, I recommend that the OEB:
  - Phase in increases over several years; other jurisdictions have phased in large budget increases over three to four years.
  - Set aside funding within the overall budget for Enbridge to help advance and shape necessary market changes; Nicor Gas funds workforce efforts at around 3% of their total portfolio budgets.
- Large budget increases will eat into the rate savings generated by amortization, so the OEB will need to match increases to the specific amortization structure to stay within the historic rate guidance.
  - Budget increases would need to be far lower than a doubling of Enbridge's proposed budgets.
  - Budget increases of 20% track closer to the OEB's historic rate guidance, with higher savings in the short term and lower increases in the long term.
  - Alternatively, budget increases could be temporary and then ramp back down to something close to (or below) Enbridge's proposed trajectory.

1.1.3. Response to Optimal's Considerations on the Overall Structure of the Cost Recovery Mechanism:

- I agree with Optimal that:
  - A single amortization cost recovery approach should be used for all programs and sectors.
  - Lost revenue is a recurring annual expense that represents a significant disincentive to utilities pursuing DSM and Enbridge should continue to recover lost revenue as an expense, even if the OEB does decide to recover program costs through amortization.
  - Performance incentives should be approached separately from the cost recovery approach.
- I disagree with Optimal's recommendation to recover performance incentives by amortizing them along with other portfolio costs. I instead recommend that Enbridge recover its full performance incentive with expense treatment, continuing historic treatment of Enbridge's DSMI, and consistent with Optimal's recommendation for lost revenues.

1.1.4. Response to Optimal's Considerations on Specific Inputs to Amortization Calculations:

- I disagree with Optimal's recommendations to:
  - Recover amortized DSM expenditures by applying the cost of debt as the cost of capital; I instead recommend the OEB apply the WACC approved in Enbridge's annual rate proceedings.
  - Set the amortization term to a fixed number of years approximately representing the weighted average measure life of a typical efficiency portfolio, which for Enbridge has exceeded 16 years from 2016 through 2021. Instead, given the potential long-term regulatory risks facing the natural gas industry, I recommend that, if the OEB decides to implement amortization, the OEB apply 5-year terms.

1.1.5. Response to Optimal's Considerations on the Use of Discount Rates for Evaluating Amortization:

- As a mathematical exercise, I don't disagree with Optimal's conclusion that customers with discount rates higher than the cost of capital applied in the amortization calculations will accrue savings in present value terms.
- I disagree with the broader policy conclusion that the use of customer discount rates represents a reasonable framework for evaluating DSM in Ontario.

1.2 Recommendations Regarding Performance Incentives

Table 1 outlines my compromise proposal for a performance incentive mechanism, combining features from Enbridge's proposal, as well as recommendations from Optimal and EFG.

Table 1: Compromise Performance Incentive Proposal

Component	Metric	Sub-Target	Frequency	5-Year Incentive Payment ($M)		Threshold (% of Proposed Plan)	
				Max	Share	Min	Max
Annual Scorecards: RA*	Net Annual Savings	7 Sub-Targets	Annual	$ 102.3	93%	50%	150%
Annual Scorecards: MY#	Participants	8 Sub-Targets	Annual	$ 6.2	6%	50%	150%
Low Carbon Transition+	MT Metrics	4 Sub-Targets	Year 2, 5	$ 2.0	2%	50%	150%
Net Benefits	------	*Eliminate*	------				
GHG Reduction	------	*Eliminate*	------				
Total				**$ 110.5**	**100%**		
Total as % of Budget				**15.5%**			

*RA=Resource Acquisition
#MY=Multi Year

Changes Recommended to Performance Incentive Management Process:
- Maintain TAM.
- Maintain Mid-Point Assessment.
- Maintain ring-fenced budgets.
- Manage 5-year budgets.
- Maintain DSMVA 15% budget increases..
- Increase maximum incentive pool if savings targets increase.
-Simplify evaluation measurements and verification requirements.

1.2.1. Recommendations Incorporated into the Compromise Proposal

1.2.1.1. Performance Incentive Components

- Maintain annual scorecard for Resource Acquisition and Multi Year programs, as proposed by Enbridge.
- Eliminate Annual Net Benefits component, as recommended by EFG.
- Maintain long term scorecard component for Low Carbon Transition program, as proposed by Enbridge.
- Eliminate Long-Term GHG Reduction component, as recommended by Optimal and EFG.
- Include multiple countervailing metrics and features, as recommended by Optimal.

1.2.1.2. Maximum Performance Incentive Payments

- Increase performance incentive pool if budgets or savings goals increase substantially, as recommended by Optimal and EFG.

1.2.1.3. Performance Metrics

- Maintain net annual savings metrics for Resource Acquisition scorecards, as proposed by Enbridge.
- Maintain participation metrics for Multi Year programs, as proposed by Enbridge.

1.2.1.4. Performance Targets

- Maintain targets proposed by Enbridge, although I understand that the OEB is considering evidence from multiple parties recommending changes to those targets.

1.2.1.5. Performance Thresholds

- Maintain 50% floors and 150% ceilings for scorecard metrics, as proposed by Enbridge.

1.2.1.6. Performance Incentive Management Process

- Maintain TAM, as proposed by Enbridge.
- Maintain Mid-Point Assessment, as proposed by Enbridge.
- Maintain ring fenced budgets, as proposed by Enbridge.
- Allow Enbridge to manage 5-year budget, as proposed by Optimal.
- Maintain DSMVA policy to increase rate class budgets by up to 15%, as proposed by Enbridge.
- Simplify evaluation measurements and verification requirements, as proposed by Optimal.

1.2.2. Recommendations Excluded from the Compromise Proposal

By maintaining components of the Enbridge proposal, I also recommend that the OEB reject certain recommendations made by Optimal and EFG, including:

1.2.2.1 Performance Incentive Components

- Reject Optimal recommendation to create a Net Benefits component tied to PAC-Plus net benefits metric.
- Reject EFG recommendation to eliminate Annual Multi Year components for the Energy Performance and Beyond Building Code programs.
- Reject EFG recommendation to shift focus of Low Carbon Transition program away from gas heat pumps.
- Reject EFG recommendation to change the Long-Term scorecard allocation to a new Long-Term Energy Intensity objective.

1.2.2.2. Performance Metrics

- Reject EFG and Optimal recommendations to change Resource Acquisition scorecards metrics from net annual savings to net lifecycle savings.
- Reject Optimal recommendation to change metrics for Multi Year programs from participation to gas savings.

1.2.2.3. Performance Thresholds

- Reject EFG and Optimal recommendations to change scorecard performance thresholds to 75% floors and to ceilings of 110%-125% (Optimal) or 125% (EFG).

1.2.2.4. Performance Incentive Management Process

- Reject Optimal recommendation to eliminate TAM.
- Reject Optimal recommendation to incorporate evaluation changes in the Mid-Point Assessment.

1.3 Recommendations Regarding Savings Benchmarks from Other Utilities

- I caution the OEB in using benchmarks provided by EFG in setting performance targets for Enbridge, since these other jurisdictions have very different regulatory environments, market conditions, and resources available to them.

2. AMORTIZATION AS A COST RECOVERY MECHANISM

This section first provides some general background on the mechanics of using amortization to recover costs for DSM expenditures. It then outlines and responds to the considerations presented in the Optimal report regarding amortization.

2.1. Amortization Calculations

2.1.1. General Amortization Calculations

This subsection describes the underlying calculations used to amortize regulatory assets like DSM expenditures. It describes the key inputs driving the calculations and illustrates the key outcomes and tradeoffs in choosing amortization versus traditional expense treatment, as well as in designing a specific amortization mechanism for Enbridge.

Utility ratemaking in Ontario and in other jurisdictions allows utilities to recover the costs they incur for all prudent expenses and investments required for them to deliver energy to customers, including cost associated with fair rates of return to utility investors.

Costs for ***expenses***[3], such as staff salaries and equipment maintenance, are recovered dollar-for-dollar without any markup for profit. Costs for long-term investments in ***assets*** such as pipelines and power plants are recovered through a combination of two items:

- ***Depreciation***, which recovers the cost of the investment over the lifetime of the asset. For example, if a utility invested $100 million in a pipeline with a useful life of 40 years, it would recover $2.5 million per year in depreciation charges. By the time the pipeline is replaced or retired after its useful life has expired, customers have repaid the full initial investment of $100 million (in nominal terms).
- ***Cost of capital***, which provides utility investors fair returns on the capital they provide to the utility for investments in long-term assets. Costs mainly include long-term debt interest (provided to utility bondholders) and equity earnings (provided to utility shareholders). Some utilities also leverage other sources of capital, such as preferred stock, short-term debt, or funds provided by customers through deposits and similar accounts. These additional sources of capital are usually only a very small portion of a utility's total capital.

Traditional utility ratemaking treats DSM costs as expenses, and so utilities recover them dollar for dollar, without any profit markup. In Ontario, Enbridge recovers DSM costs as expenses through a combination of base rates and variance accounts, with some costs recovered in the year after they are incurred (e.g., some 2020 costs were recovered beginning in 2021). When costs are deferred, these costs accrue carrying charges calculated at the weighted average cost of capital (WACC) Enbridge pays to investors who provide the capital that allows Enbridge to delay recovery. The variance accounts also

[3] Optimal refers to traditional expense recovery treatment as "contemporaneous cost recovery." Because some utilities delay revenue recovery for DSM expenditures, even with expense treatment, expenditures and revenue are not exactly contemporaneous. For this reason, this report refers to "expense" treatment in covering those issues Optimal refers to as "contemporaneous" in its report.

include balancing provisions that ensure that revenues actually recovered from customers match Enbridge's actual costs.

(In Ontario, the OEB ***does*** allow Enbridge to charge a profit margin on recovered DSM expenses through a separate DSM Incentive (DSMI) variance account charged to customers, and calculated as a markup from approved expenses. With this deviation from traditional ratemaking, the OEB provides regulatory guidance, through an earnings-based performance incentive, for Enbridge management to prioritize DSM over other activities and to also improve its performance in delivering DSM. I address performance incentives in more detail in Section 2 of this report. For the remainder of this Section 1, I will refer to traditional expense treatment, without profit markups.)

With amortization, DSM costs are treated as a regulatory asset instead of an expense. Amortization cost recovery uses an approach consistent with the example provided earlier for pipeline and power plant assets, with one minor difference: with regulatory assets, investment costs are recovered through amortization, rather than the depreciation used for physical assets. Otherwise, the calculations and cash flows are identical to the example provided earlier for pipelines and power plants.

2.1.1.1. Single-Year Portfolio Analysis

Figures 1 and 2 compares the cash flows associated with expense and amortization treatment for an individual year of expenditures: in this example for Enbridge's $142 million expenditures proposed for 2023. Figure 1 shows cash flows associated with expense treatment. Figure 2 shows amortization treatment, assuming a 10-year amortization term and assuming a cost of capital[4] of 5.8%. This cost of capital is approximately equal to the WACC approved in Enbridge's recent rate cases. In subsequent sections of this report, I will address the effect that changes to the amortization term and changes to the cost of capital have on amortization revenue requirements.

For clarity and ease of understanding, I used some simplifying assumptions to develop these figures and the other analyses presented in this Section. These include:

- Cash flows are assumed to occur annually and at the beginning of each year.
- I calculate no carrying charges on expenses deferred for recovery to future years or to variances between actual expenses incurred versus revenues recovered. I assume all expenses are recovered in the year they occur.
- Enbridge's capital structure is approximate, and assumed to include only debt and equity, with assumptions for capitalization, costs of capital, and taxes shown in Table 2.

As shown in Figure 1, with expense treatment, Enbridge incurs $142 million in costs in 2023, and recovers the same $142 million in revenue. The net present value of the total cash flow to Enbridge is $0 and Enbridge receives no earnings.

[4] The Optimal report uses the term "interest" to describe the costs of capital applied in amortization calculations. This term is confusing, because Enbridge raises capital from both debtholders (who are paid interest) and shareholders (who receive earnings). In this report I use the term "cost of capital" to refer to all costs paid to any form of investor.

Figure 1: Cash Flow Analysis, Expense Treatment

Figure 2: Cash Flow Analysis, Amortization Treatment

With amortization treatment, Enbridge incurs the same $142 million in costs to fund DSM programs in 2023. Enbridge recovers $142 million in amortization, spread in equal annual payments over the 10-year amortization term from 2024 through 2033. Enbridge also recovers investor costs of capital over the 10-year investment life. Costs of capital are highest in 2024, when the WACC is applied against the entire $142 million initial regulatory asset balance. Each year after 2024, as amortization payments reduce the unamortized asset balance, annual costs of capital charges decline.

Again, the net present value of the total cash flows to Enbridge is zero. That is, the sum of the annual revenues provided to Enbridge, when discounted at Enbridge's discount rate (again, set at Enbridge's WACC), is exactly equal to the $142 million in expenditures incurred in 2023. Or, put another way, the revenues Enbridge receives with amortization treatment allows Enbridge to earn exactly it's WACC on the investment in DSM.

Table 2: Cost of Capital Assumptions*

	Capital Structure	Cost of Capital	Weighted Average
Long Term Debt	64%	4.0%	2.56%
Equity	36%	9.0%	3.24%
Total Capital	100%		5.80%
*Values are approximate, rounded, and only used for illustrative purposes in calculations used in this Section 2.			

2.1.1.2. 20-Year Portfolio Analysis

Figure 3 expands the analysis to cover 20 years of portfolio delivery. The analysis assumes that Enbridge delivers the DSM portfolio not only in 2023, but also in 2024 through 2027 (as outlined in Enbridge's proposed DSM Plan), and then continuing out through 2042. Portfolio budgets grow consistent Enbridge's proposed DSM Plan through 2027 (5% per year, including 2% inflation plus 3% real growth), and then at inflation out through 2042. The analysis extends out through 2052 to ensure that all cash flows associated with the investments are captured.

Figure 3: Revenue Requirements-20-Year Portfolio

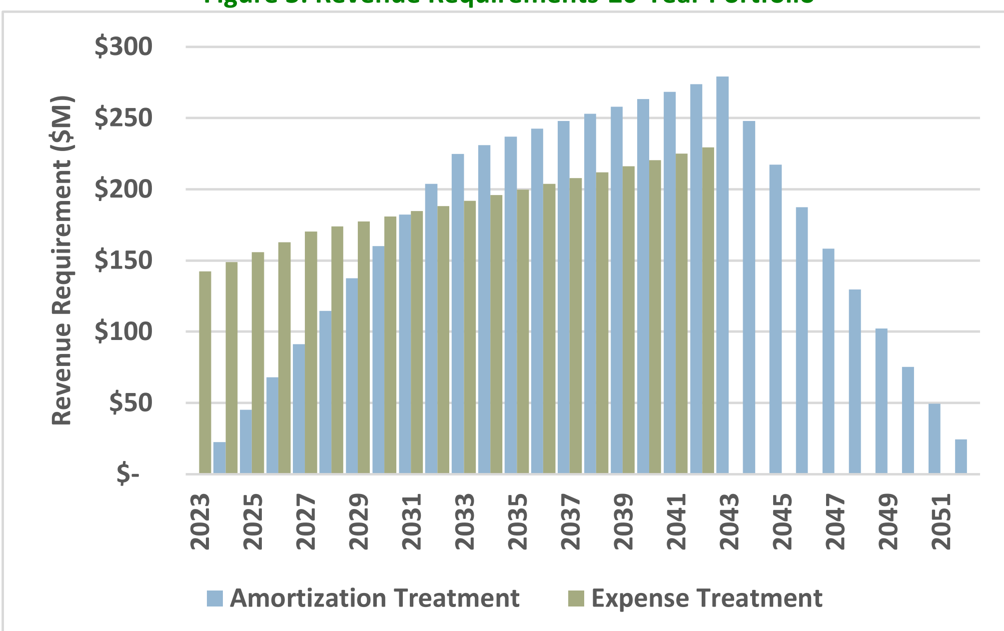


Figure 3 shows that, in the early years, amortization reduces the revenues required to support the DSM investments compared to expense treatment. Consistent with the single-year analysis shown in Figure 2, in the early years only a portion of the total investment is being recovered. Results in 2024 are identical to the results shown for the single-year analysis in Figure 2: the expense approach requires $142 million in revenue requirement and the amortization approach requires only $22 million ($14.2 million for amortization, around $8 million for cost of capital). In 2025, even though amortization revenue requirements almost double, they are still far below the 2025 expense treatment, which only grows by 5% per year.

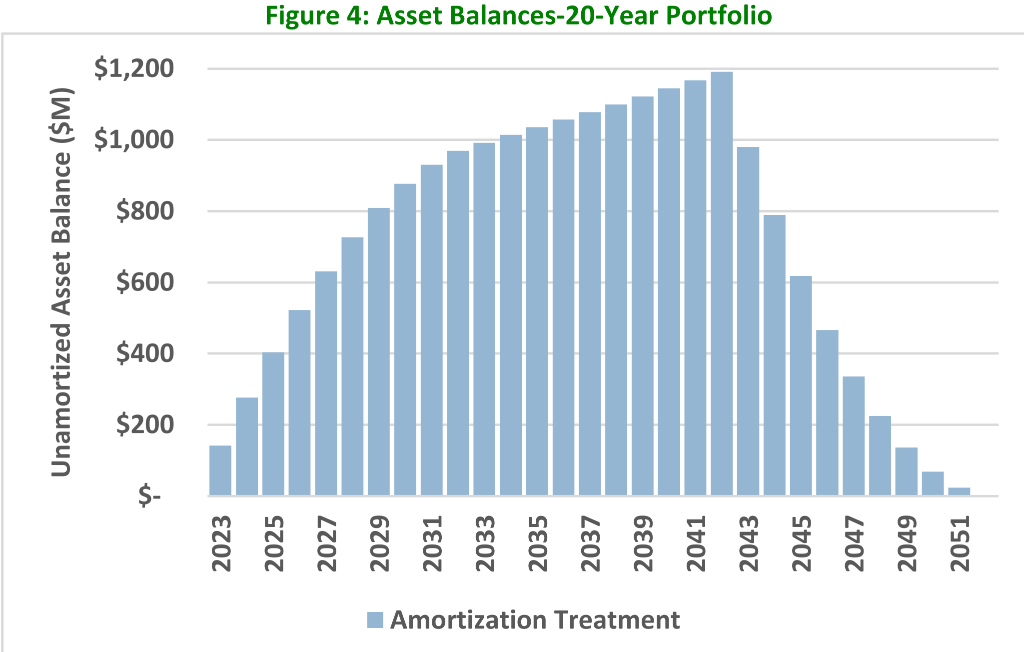
As time goes on, amortization revenue requirements continue to grow and eventually exceed revenues from expense treatment. In this example, amortization treatment begins to exceed expense treatment by 2031. For example, in 2033, amortization revenue requirements include amortization payments for each of the 10 portfolios implemented from 2023 through 2032, and this total is almost as much as the full 2033 budget ($169 million vs. $192 million). With additional cost of capital requirements, amortization revenue requirements now exceed those for expense treatment.

Once investment stops in 2042, it takes another 10 years of revenues to fully compensate Enbridge and its investors for the initial DSM portfolio investments. By 2052, the analysis is complete, and all payments have been made.

In present value terms, the revenue requirements in each scenario exactly offset the initial expenditures made by Enbridge to implement the DSM portfolios. This is simply an extension of the one-year analysis shown in Figure 2. In other words, Figure 3 combines 20 consecutive versions of the one-year analysis. In the end, as was true in the one-year analysis, revenue requirements exactly offset the initial investments in present value terms (when discounted at the utility's cost of capital).

Figure 4 shows the unamortized asset balance for the 20-year amortization scenario. It grows from the initial $142 million investment in 2023 to reach just under $1.2 billion by 2042. With no further investment after 2042 (for the purpose of this example), but with continued revenue, asset balances decline to zero by 2052.

Figure 4: Asset Balances-20-Year Portfolio



The size of this regulatory asset balance could be a concern to Enbridge investors and credit rating agencies, as well as to the OEB and to Enbridge's customers. Since the asset is not backed by physical property, Enbridge is at risk if a future OEB Panel would ever decide to stop funding the ongoing cost recovery required to fully repay Enbridge's bondholders and shareholders. This is especially true if a future OEB Panel would decide to stop authorizing ongoing DSM program implementation, because customers would need to continue to fund the amortization cost recovery on past investments, even though Enbridge would no longer be providing DSM services.

2.1.1.3. Amortization Calculation Summary

Some of the results shown in this section depend on the specific DSM budgets, costs of capital, and amortization term used as inputs to the revenue requirements calculations. However, some relationships and patterns emerge in all cases (or under most cases with likely values for key inputs and not extreme values). These key results include:

- Under amortization, revenue requirements always decline in the early years compared to expense treatment (as long as portfolio budgets do not decline precipitously).
- Under amortization, revenue requirements always increase in later years compared to expense treatment (as long as portfolio budgets do not grow at rates far exceeding the cost of capital over the analysis horizon.)
- Over the full cost recovery period, the present value of revenue requirements is identical for both amortization and expense treatment (when using the utility's cost of capital as the discount rate). Under both treatments, the present value of revenue requirements exactly equals the present value of DSM expenditures. In other words, the discounted cash flow for both treatments equal zero; because revenue exactly equal costs with expense treatment, and because the utility earns exactly it's authorized cost of capital with amortization treatment.
- Under amortization, a regulatory asset builds up, although the size of the asset depends on levels of spending and the amortization term.

2.1.2. Amortization Term

2.1.2.1. Amortization Terms Applied in Other Jurisdictions

Table 3 shows the range of amortization terms used in jurisdictions amortizing DSM expenditures in North America. This table is similar to Table 6 presented in Optimal's report, with three exceptions:

- My Table 3 includes British Columbia, which was excluded from the Optimal report. The British Columbia Utilities Commission (BCUC) authorizes FortisBC to recover its DSM expenditures with amortization.[5]
- My Table 3 includes two separate amortization terms for New Jersey, which applies a 5-year term to information technology assets and a 10-year term to other DSM expenditures.[6]

[5] BCUC Order G-10-19, FortisBC Energy Inc. Application for Acceptance of 2019-2022 Demand Side Management Expenditures Plan, January 17, 2019.
[6] "Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs", Docket Nos. QO19010040, QO19060748, QO17091004, State of New Jersey Board of Public Utilities, June 10, 2020.

- My Table 3 excludes Missouri. Both major electric utilities in Missouri currently use expense treatment to recover DSM expenditures and do not amortize these costs.[7] Optimal's 6-year term data references the amortization term Missouri electric utilities use to recover performance incentives, which are awarded at the end of the cycle, and then recovered over two-year periods. However, this amortization merely affects the timing (and ultimate value) of the performance incentive, and doesn't affect the recovery of the underlying costs required to fund the DSM portfolio. I discuss the recovery of performance incentives in more detail in Section 2.2.3.3.2 of this report.

Table 3: Amortization Terms Applied in Other Jurisdictions

Jurisdiction	Amortization Term	Optimal Amortization Term Data[8]	Notes
BC	10 years		
DE	5 years	5 years	
IL	WAML*	WAML	ComEd WAML for 2019 was 11 years.
MD	5 years	5 years	
MO9	N/A	6 years	Electric utilities do not amortize DSM expenditures.
NJ	10 years 5 years for IT	10 years	
NY	10 years	10 years	
UT	10 years	10 years	
*WAML=Weighted Average Measure Life			

Almost all jurisdictions use 5 or 10 years as the amortization term. Illinois electric utilities apply the weighted average measure life (WAML) of the measures installed by the portfolio as the amortization term. For ComEd, this weighted average life has typically been close to 11 years. Applying the WAML has the advantage of exactly matching the recovery term to the duration over which the measures save energy. This alignment helps ensure that the customers paying for DSM are also those receiving the associated benefits, in the form of direct energy savings for participants and utility system benefits for all customers.

In 2018, FortisBC petitioned the BCUC to change the amortization term from 10 years to their portfolio WAML, which was approximately 16 years. The BCUC denied that application based, primarily, over the uncertainty and stability of the WAML estimates, as well as concerns over intergenerational rate impacts. In its decision, the BCUC stated that "increasing the amortization period would increase the overall cost of the DSM Plan to ratepayers…this must be weighed against the inter-generational equity

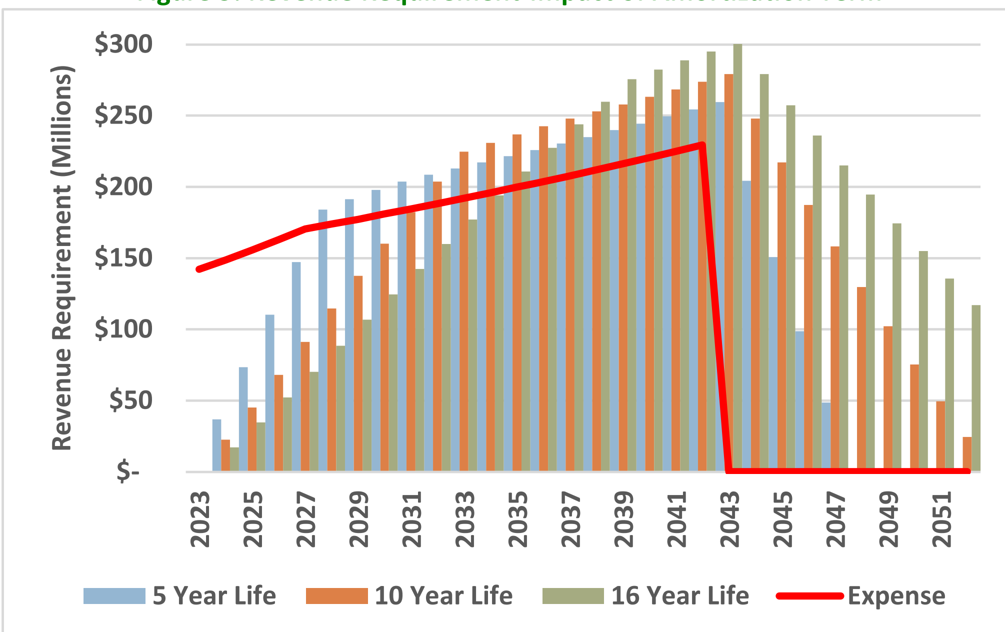
[7] Personal communication with Craig Aubuchon, Ameren Missouri and Lisa Starkebaum, Evergy Missouri West.
[8] Optimal Report, Table 5.
[9] In its original report, Optimal identified Missouri as a jurisdiction that applies amortization, although Missouri's electric utilities do not amortize DSM expenditures. In Optimal's updated report, provided as evidence on January 26, Optimal identified Missouri gas utilities as applying amortization. Missouri's gas DSM portfolios are much smaller than electric portfolios. Optimal did not provide amortization terms used by Missouri's gas utilities. I have not had time since Optimal's updated filing to confirm this characterization of Missouri's gas utilities.

consideration, whereby future ratepayers would be paying for benefits that would be enjoyed by current ratepayers. Given the issues with the 16-year estimate…the Panel is reluctant to cause ratepayers to pay more when it is not clear how far in the future the benefits will actually extend."[10]

2.1.2.2. Impact of Amortization Term on Amortization Calculations

Figure 5 shows how the choice of asset term has a substantial impact on revenue requirements, comparing the 10-year term used earlier with terms of 5 years (the shortest term used in other jurisdictions) and 16 years (Enbridge's approximate WAML, as described in Section 2.2.1). All scenarios assume a cost of capital set to Enbridge's approximate WACC, shown earlier in Table 2. Figure 5 also shows revenue requirements associated with typical expense treatment.

Figure 5: Revenue Requirement-Impact of Amortization Term



Lower asset terms significantly increase revenue requirements in the short term, since the majority of revenue requirements come from the amortization component (as opposed to cost of capital), and those amortization charges are inversely proportional to asset lives (with higher annual charges for shorter lives). Through 2028, 5-year asset terms require revenues more than double those for 16-year terms, and 10-year terms require revenues around 30% higher than with 16-year terms. Over time, once the 2023 portfolio is fully amortized, rates are much closer across the three scenarios, and the 5-year revenue requirements are actually lowest; around 14% lower than with 16-year terms and around 7% lower than with 10-year terms.

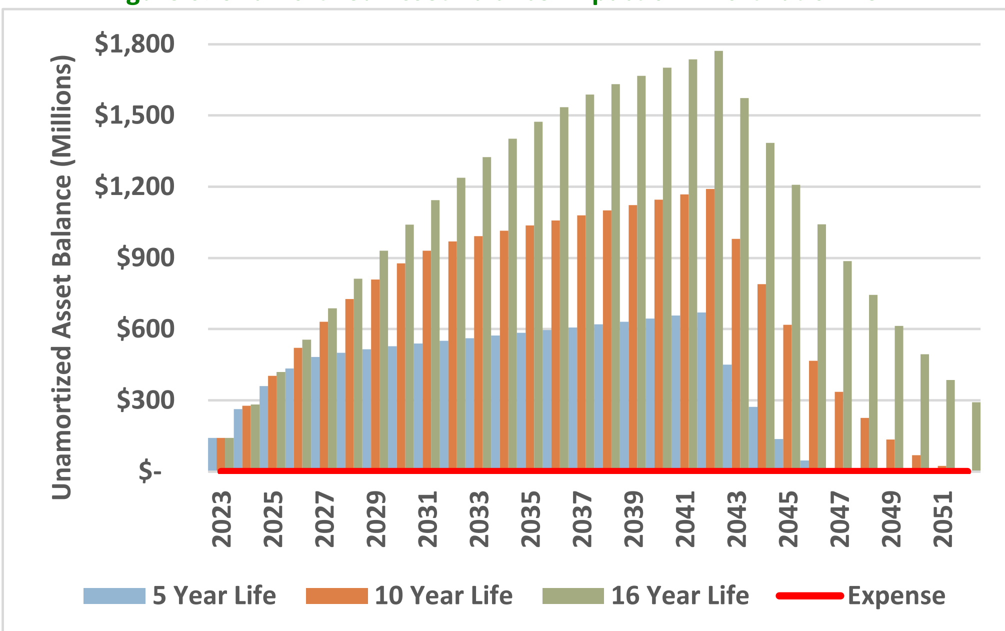
This dynamic also causes revenues under 5-year terms to exceed those with typical expense treatment more quickly. This is an important consideration if the OEB desires to employ amortization to allow higher DSM budgets, while staying within the rate levels set out in the Enbridge's proposed policy

[10] BCUC Order G-10-19, FortisBC Energy Inc. Application for Acceptance of 2019-2022 Demand Side Management Expenditures Plan, January 17, 2019.

framework. Amortization revenues with 5-year terms surpass expense revenues (i.e., revenues consistent with the Enbridge policy framework) by 2028. Revenues under 10-year terms do not exceed expense revenues until 2032 and 16-year terms further delay the crossover until 2036.

Figure 6 shows that unamortized asset balances also build up to much higher levels with longer asset terms. This is also driven by the annual amortization dynamic mentioned above; since longer asset terms result in lower annual amortization charges, unamortized balances draw down more slowly. By 2042, with 16-year terms, the unamortized balance is 2.6X higher than with 5-year terms ($1.8 billion vs. $671 million) and with 10-year terms the unamortized balance is 1.8X higher than with 5-year terms ($1.2 billion vs. $671 million).

Figure 6: Unamortized Asset Balance-Impact of Amortization Term



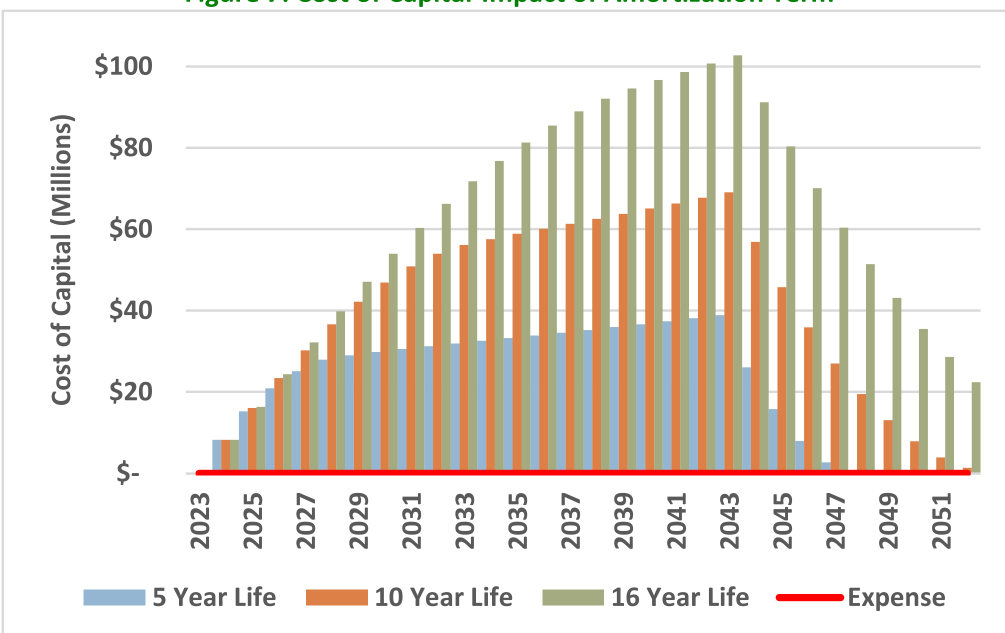
As mentioned above, large regulatory asset balances create risks for Enbridge's investors should future OEB Panels change their policies supporting DSM programs. These regulatory assets also pose risks should future OEB Panels change their policy supporting the natural gas utility industry in general. For example, the EFG report in this proceeding recommends that Ontario consider "whether future building codes should allow for any fossil fuel heating, water heating, cooking and other gas end uses[11]." If regulatory policies do actually transition away from natural gas in the future, some investors and regulators worry that a mismanaged transition could have negative consequences on customers and investors. For example, some regulators fear that large scale electrification could results in spiraling gas rates, as the fixed costs of the gas system are spread over fewer remaining customers. This is especially worrisome if higher income customers drive early electrification, leaving low income or other disadvantaged groups to shoulder ongoing costs. Investors might also worry that a mismanaged transition would result in largescale asset write offs in attempts to lessen rate impacts. These investors

[11] EFG Report, page 38.

might worry that regulatory assets not backed by physical property would be at higher risk for write-downs. To mitigate these risks, some regulators are already recommending that gas asset lives be lowered to accelerate the draw-down of unamortized asset balances.[12]

Figure 7 shows that utility cost of capital for bond interest and shareholder earnings also build to much higher levels with longer asset lives. Since cost of capital is charged against the unamortized asset balance, Figure 7 has the exact same pattern as the unamortized asset balances shown in Figure 6, but the magnitudes are much smaller. Again, by 2042, with 16-year terms, the costs of capital are 2.6X higher than with 5-year terms ($101 million vs. $38 million) and with 10-year terms the costs of capital are 1.8X higher than with 5-year terms ($68 million vs. $38 million). In the long term, costs of capital make up about 15% of total revenue requirement with 5-year terms; around a quarter of the total with 10-year terms; and around a third of the total with 16-year terms.

Figure 7: Cost of Capital-Impact of Amortization Term



To summarize the impact of asset terms on amortization, shorter asset terms (compared to longer terms) result in:

- Much higher revenue requirements in the short term.
- Slightly lower revenue requirements in the long term.
- Revenue requirements that exceed those associated with typical expense treatment more quickly.
- Much lower unamortized asset balances.
- Much lower cost of capital charges to customers.

[12] See, for example: Regulatory Assistance Project, *Under Pressure: Gas Utility Regulation for a Time of Transition,* May 2021.

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.

The key takeaways from these other jurisdictions are:

- In those jurisdictions that do not adjust the cost of capital to provide a performance incentive, all jurisdictions apply the weighted average cost of capital approved in the utility's most recent rate case.
    - Note that the Optimal report identified New Jersey as a jurisdiction applying performance incentives through adjustments to cost of capital. While New Jersey has crafted a performance mechanism, the New Jersey Board of Public Utilities has deferred implementation of the approach until at least Plan Year 5, which will begin in October 2025.[15]
- The two jurisdictions that do currently adjust the cost of capital for performance generally apply the same approach to the cost of capital for DSM investments as they apply for other long-term rate base assets:
    - Illinois calculates the WACC applied to DSM assets using a formula rate process. The formula combines returns on debt and equity in a typical weighted average calculation. The formula also calculates return on equity (ROE) from a base ROE (calculated as a defined risk premium added to current costs for US Treasury Bills) with further adjustments for performance. This is the same general approach used to calculate returns for other rate base assets in Illinois, although the performance adjustments differ for different assets and activities required to deliver utility service.
    - New York calculates a WACC that applies to the entire rate base—including physical assets as well as regulatory assets like DSM expenditures—using a performance-based ratemaking (PBR) process. The PBR calculates the ROE used in the WACC calculation by adjusting the utility's approved ROE to reflect performance on multiple performance metrics, including 6 groups of metrics for electric and gas DSM performance. Thus, the ROE applied to DSM assets is the same ROE applied to other rate-base assets.
- As discussed in Table 3, Missouri electric utilities do not currently amortize their DSM expenditures.

2.1.3.2. Impact of Cost of Capital on Amortization Calculations

Figure 8 shows how the choice of cost of capital influences revenue requirements, comparing revenues calculated with Enbridge's full cost of capital (approximately 5.8% as shown earlier in Table 2) to revenues calculated solely from the cost the long-term debt alone (approximately 4%). Both of these scenarios assume a 10-year asset term. For comparison, Figure 8 also shows revenue requirements associated with typical expense treatment.

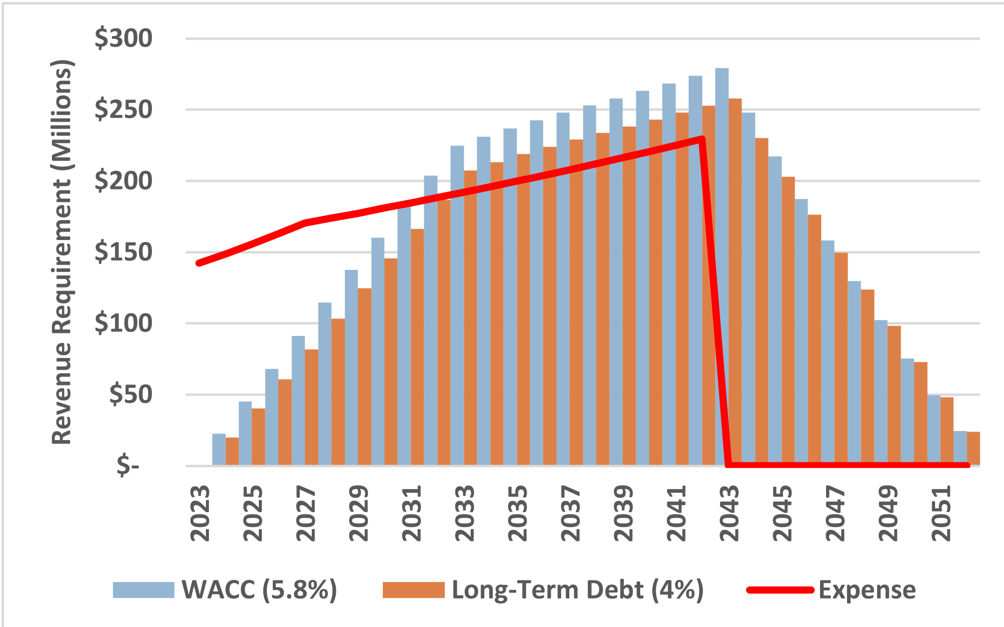
Figure 8 shows that lower cost of capital results in lower revenue requirements. Amortization charges and the resulting unamortized asset balances are identical between the two scenarios, since both apply 10-year asset terms, and so the difference in revenue requirements comes entirely from the cost of

[15] "Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs", Docket Nos. QO19010040, QO19060748, QO17091004, State of New Jersey Board of Public Utilities, June 10, 2020.

capital. Applying debt rates lowers revenue requirements by around 11% in 2024, with the difference declining to around 8% by 2033, once the 2023 portfolio is fully amortized.

Revenues for the WACC scenario exceed revenues required under traditional expense treatment beginning in 2032 (as was already shown in Figure 5). With the debt scenarios, the crossover is delayed until 2033.

Figure 8: Revenue Requirements-Impact of Cost of Capital



To summarize the impacts of cost of capital on amortization, higher input values for cost of capital (compared to lower inputs) result in:

- Higher revenue requirements in all years, with the difference larger in the early years.
- Revenue requirements that exceed those associated with typical expense treatment more quickly.
- Identical unamortized asset balances.
- Higher cost of capital charges to customers.

2.2. Response to Optimal Conclusions and Considerations

This section provides my responses to the conclusions and considerations provided in the Optimal report.

2.2.1. Summary of Optimal Conclusions and Considerations

The Optimal report presents one overall conclusion on the use of amortization as a cost recovery mechanism in Ontario, supported by six additional considerations for the OEB.[16]

[16] Optimal Report, pages 16-17.

Optimal's overall conclusion is that "…amortization could be a good tool to enable program expansion, if that is desired, while minimizing short term rate impact." However, this conclusion is tempered in a footnote: "This statement is contingent on a desire to expand the programs. We would not recommend amortization without an accompanying expansion in the efficiency program goals and costs."

Optimal's additional considerations include three addressing the overall structure of the cost recovery mechanism (emphasis added):

- "A ***single cost recovery approach*** (amortization or cost recovery) should be used for all programs and sectors to avoid the complexity involved in using different approaches for different programs."
- "***Lost Revenue*** is a recurring annual expense and should not be amortized with the program costs."
- "Approach the ***performance incentive*** separately from the cost recovery approach." Effectively, this consideration recommends against calculating performance incentive through ROE bonuses factored into the cost of capital used in the amortization calculation (as is done in Illinois). Instead, Optimal recommends "maintaining a separate performance metric type approach, even if program costs are ultimately amortized".[17] In an interrogatory, Optimal also clarifies that they recommend that performance incentives should recovered through "amortization along with program costs", and not expensed as recommended for lost revenue.[18]

Optimal's considerations also include two addressing the specific inputs to the amortization calculation, should the OEB choose that approach (emphasis added):

- The ***cost of capital*** provided to Enbridge's investors should be "set at the utility's cost of debt".[19]
- Regarding the ***term*** over which costs are amortized, Optimal suggests "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."[20] The weighted average measure life of Enbridge's portfolio has exceeded 16 years from 2016 through 2021.[21]

  However, Optimal also notes that a shorter life could be used "as a good compromise between those stakeholders who want amortization and those that worry about increased interest payments and the optics of nominal [system benefits charge] rates that are higher with continuous program investment that has occurred for longer than the loan term"[22] and also that a shorter life could be used "as a compromise between those who want to amortize and those who want full annual cost recovery".[23]

[17] Optimal Report, page 8.
[18] Response to 7-EGI-2-OEB Staff.1.
[19] Optimal Report, page 16.
[20] Optimal Report, page iii.
[21] Exhibit I.1.EGI.CCC.1, page 3.
[22] Optimal Report, page iii.
[23] Optimal Report, page 16.

Finally, Optimal provides one consideration addressing the appropriate discount rate for evaluating amortization (emphasis added):

- "…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." Earlier in the report, Optimal provides examples using a customer discount rate of approximately 10% to show customers receiving long term savings in present value terms.

2.2.2. Response to Optimal Overall Conclusion

Optimal did not provide a firm overall recommendation, instead concluding that, if the OEB wanted to increase DSM budgets, amortization could help accommodate increases within the OEB's historic guidance on rate increase. I agree with this general conclusion. As I described in Section 2.1, amortization could allow the OEB to achieve both of these policy objectives at the same time, but only in the short term; in the longer term, amortization drives higher rates, while also creating new concerns around regulatory asset balances.

In my view, the OEB must address three key questions before moving forward with amortization:

1. What level of budget increases are desired?
2. What amortization structure will the OEB implement, specifically what amortization term and what cost of capital?
3. How should competing policy objectives be balanced, specifically, increases in DSM budgets, short- and long-term rate levels, and acceptable regulatory asset balances.

Defining the appropriate budget increases is beyond the scope of my report, although I understand that other parties in this proceeding have addressed this topic. However, I do recommend that, if the OEB approves a substantial budget increase, that it phase in the increase over several years. For example, other jurisdictions have phased in new and expanded portfolios over a period of one plan cycle, which is typically three to four years in other jurisdictions. The exact timing will depend on the magnitude of the budget increase; larger increases will require a longer phase-in period.

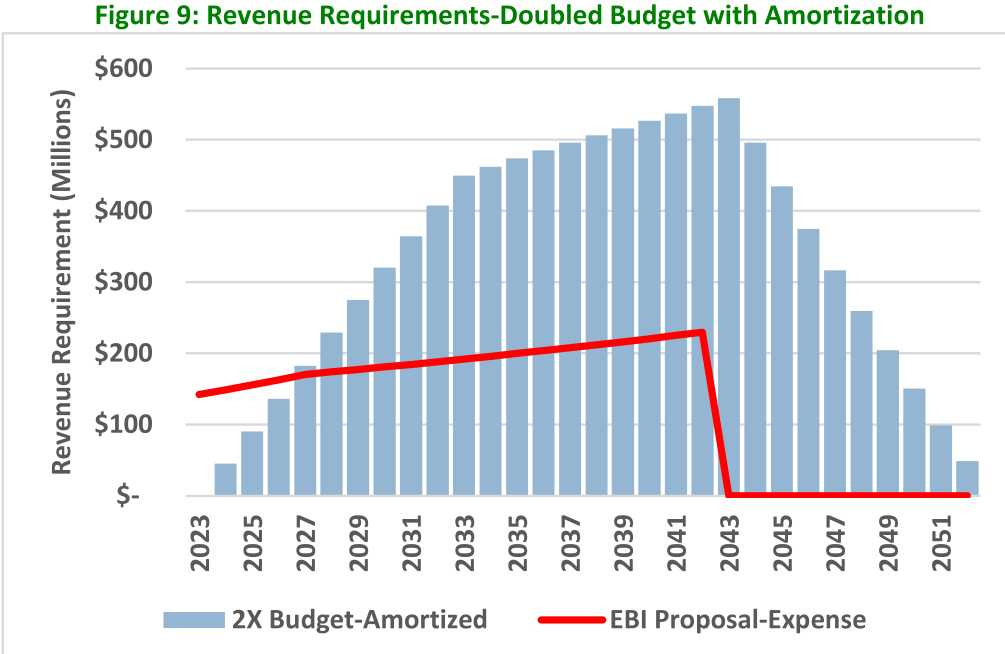
By phasing in budget increases, the OEB will allow Enbridge and its implementation partners—the trade allies and implementation contractors responsible for deploying the higher budgets—a chance to ramp up the required infrastructure. At $142 million, Enbridge already deploys one of the largest gas DSM portfolios in North America, and so substantial budget increases will likely require structural market changes to accommodate more funding.

I also recommend that the OEB set aside funding within the overall budget for Enbridge to help advance and shape these market changes. For example, Enbridge may need to foster workforce development to ensure the market has enough trade allies and implementation contractors to meet expanded market needs. These workforce needs may include new businesses as well as new workers. Workforce development efforts could also promote industry certifications and other trainings to help workforce quality improve along with expanded quantities. Other jurisdictions also target workforce activities to disadvantaged populations to ensure that new jobs and businesses also benefit underserved communities. The appropriate level of workforce development funding will depend on the magnitude of the budget increase. As one example, Nicor Gas in Illinois funds workforce efforts at around 3% of their total portfolio budgets.[24]

Large budget increases will also eat into the rate savings generated by amortization, so the OEB will need to match increase to the specific amortization structure to stay within the historic rate guidance. For example, Figure 9 shows a doubling of budgets from Enbridge's proposal, with amortization revenues calculated using a 10-year term and Enbridge's WACC. The red line in Figure 9 shows revenues under traditional expense treatment assuming Enbridge's proposed trajectory of 5% annual budget increases.

Consistent with my discussion in Section 2.1.1, in the early years, revenues decline substantially despite the large budget increase. However, by 2027, amortized revenues exceed the current budget trajectory, and by 2042 revenues are 2.4 times the OEB's historic rate guidance. Doubling budgets would also double the magnitude of Enbridge's unamortized regulatory asset, which, with a 10-year measure life, would reach $2.4 billion by 2042.

Figure 9: Revenue Requirements-Doubled Budget with Amortization

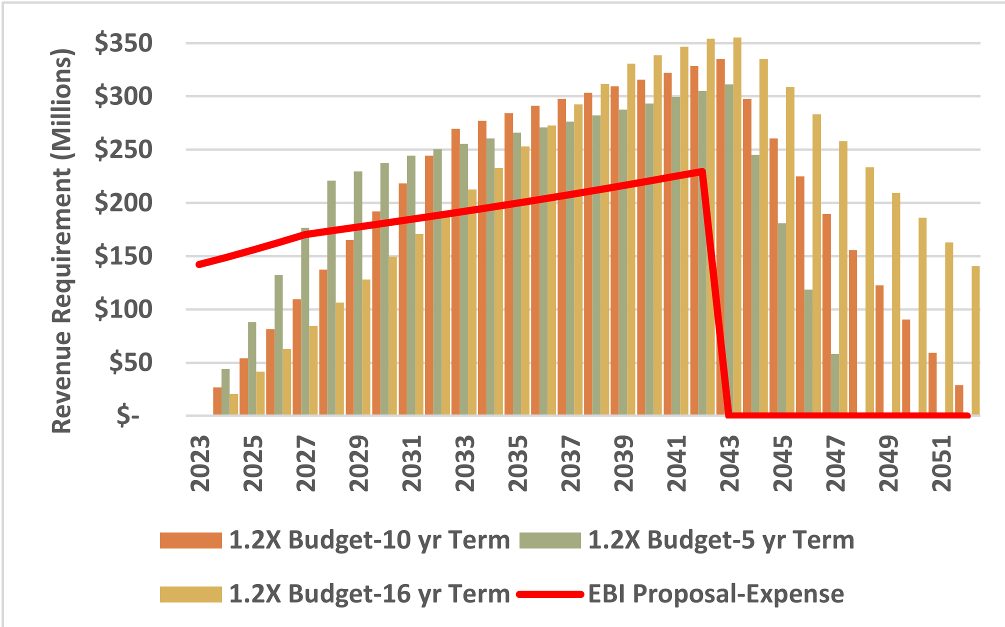


If the OEB wishes to continue meeting its historic guidance on rate impacts, budget increases would need to be far lower than this 2X adjustment. Figure 10 shows more modest increases of 20%, with amortization calculated at Enbridge's WACC and various amortization terms. These scenarios track closer to the OEB's historic rate guidance, with higher savings in the short term and lower increases in

[24] *Nicor Gas Energy Efficiency Plan, January 2022-December 2025*. Illinois Commerce Commission Docket 21-0154, March 1, 2021.

the long term. Additional scenarios could be developed that test different budget increases, including scenarios that provide temporary increases that ramp back down to Enbridge's proposed trajectory.

Figure 10: Revenue Requirements-20% Budget Increase, with Amortization



2.2.3. Response to Overall Structure of the Cost Recovery Mechanism

I agree with most of Optimal's considerations and recommendations regarding the overall structure of the cost recovery mechanism.

2.2.3.1. Single Cost Recovery Approach

I agree that a single cost recovery approach should be used for all programs and sectors. I agree that applying different approaches for different programs or sectors or other cost breakdowns introduces unnecessary complexity into the cost recovery process, as well as for the accounting systems, reporting systems, and regulatory filings necessary to support a hybrid approach.

2.2.3.2. Lost Revenue Cost Recovery

I agree that lost revenue is a recurring annual expense that represents a significant disincentive to utilities pursuing DSM. I agree with Optimal's suggestion to continue Ontario's current lost revenue practice and recover lost revenue as an expense. I also agree with Optimal's suggestion that, if the OEB does decide to recover program costs through amortization, that lost revenues be excluded from the amortization calculations and recovered instead using expense treatment.

2.2.3.3. Performance Incentives Calculation and Cost Recovery

I partially agree with Optimals' conclusions regarding performance incentives. I agree with Optimal's suggestion that performance incentives be approached separately from the cost recovery approach. I disagree with Optimal's recommendation to recover performance incentives by amortizing them along with other portfolio costs.

2.2.3.3.1. Performance Incentive Calculations

As Optimal describes in its report, rewarding utilities through adjustments to cost of capital can result in unintended consequences, where the magnitude of incentives become divorced from performance. For example, Figure 11 portrays the Illinois performance incentive, which rewards utilities exceeding savings goals by increasing ROE (which is a portion of the overall cost of capital) by up to 2 percentage points, and penalizes underperforming utilities with decreases of up to 2 percentage points. For illustration, Figure 11 assumes a $100 million initial budget, starting in 2023, and growing at inflation; a 10-year term; and Enbridge's capital structure.

Figure 11 shows earnings growing year after year, directly tracking the increase in equity capital invested in the DSM portfolio. Earnings at target performance grow from around $3 million in 2023 to $24 million by 2042. Earnings grow steeply at first, reflecting repeated annual portfolio investments, but level out after 10 years once the initial investments are fully amortized.

Figure 12 illustrates the performance incentive embedded in the Illinois approach; that is, the difference between earnings at the performance-adjusted ROE compared to earnings at the utility's authorized ROE. Maximum incentive payments grow from $700 thousand, to $1.4 million, to $2.0 million and up to around $4.5 million in year 2032. In other words, even if the utility generates the same saving in each year, compared to 2024, the performance incentive doubles in 2025 and triples in 2026, and then continues to climb. That is, incentive payments are largely divorced from performance, at least in the early years.

Figure 11: Illinois Return on Equity Performance Incentive-Overall Cost Recovery

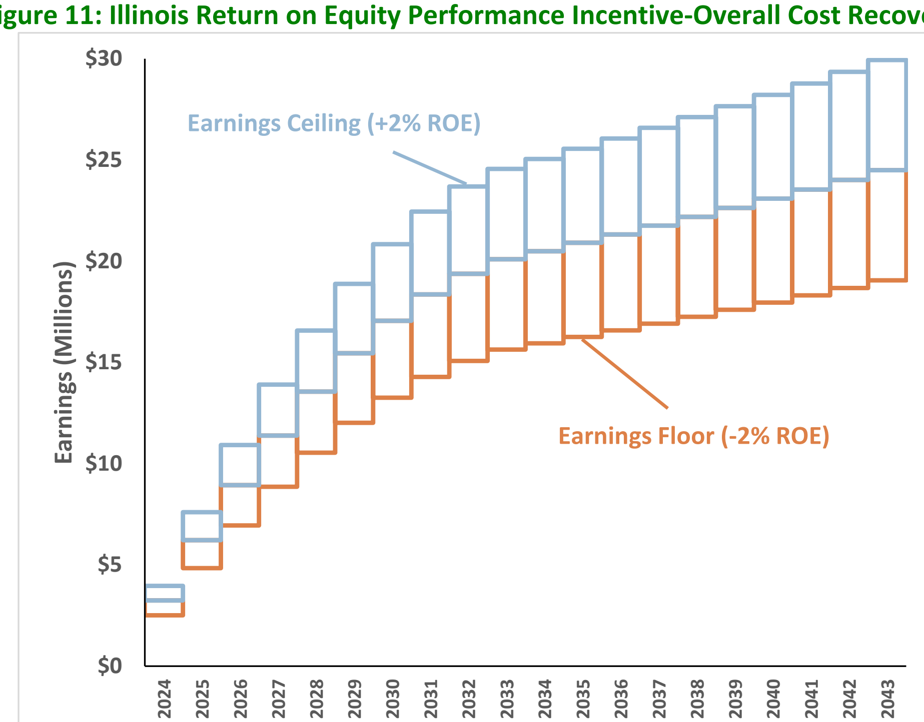


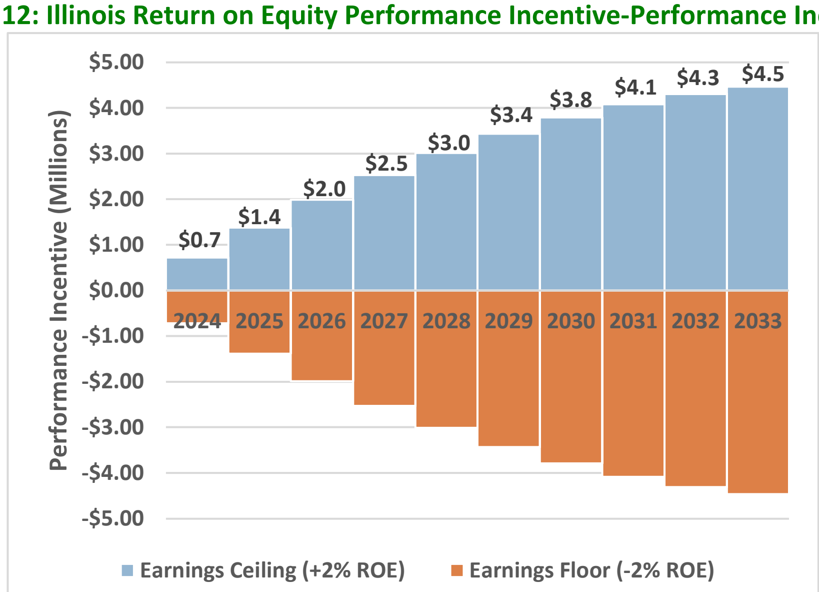
Figure 12 also shows how the Illinois approach results in negative performance payments for savings below target. That is, shareholders end up paying penalties back to customers when utilities miss savings targets. When utilities exactly meet targets, they earn no performance incentive. Over the long term, Illinois utilities only earn sustained incentive payments for consistently exceeding targets. Without consistent performance above targets, utilities earn incentives in some years, and pay penalties in others, but on average these balance out. That is, the risk-adjusted performance incentive in Illinois is close to zero.

This penalty structure and risk balance is rare and unique to those jurisdictions structuring performance incentives as ROE bonuses. As the Optimal report showed in its Table 6, only 3 jurisdictions rely on ROE adjustments, while 10 jurisdictions provide incentives through bonuses structured as markups on DSM expenditures (like Enbridge's current approach). All 10 set minimum incentives to zero, but none assess penalties. And all 10 provide some rewards, even at performance levels 20% to 30% below target. On the other hand, Illinois levees penalties when savings fall below target at all.

For these reasons, I agree with Optimal's recommendation to separate performance incentives from the amortization approach. I don't know of any other amortization jurisdictions that apply Optimal's recommendation, but it is a creative solution to the problems illustrated with the Illinois example, and I endorse it. It keeps separate two separate policy objectives that can get conflated:

- The desire to lower rate impacts by asking utility investors to fund DSM portfolio investments; this objective is addressed through the amortization cost recovery approach that repays investors for their cost of capital.
- The desire to provide utility management a profit incentive to prioritize DSM over other investment opportunities and to also improve portfolio performance; this objective is addressed through the performance incentive mechanism that provides investors a premium return on DSM investments.

Figure 12: Illinois Return on Equity Performance Incentive-Performance Incentive



In this Section 2 of my report, I focus on the amortization issues. My Section 3 provides more information on performance incentive mechanisms.

2.2.3.3.2. Performance Incentive Cost Recovery

I disagree with Optimal's recommendation to recover performance incentives by amortizing them along with other portfolio expenditures. This approach greatly reduces the magnitude of shareholder earnings and sends the wrong signal to Enbridge management. I instead recommend that, if the OEB does decide to implement amortization, the OEB continue to provide the performance incentive with expense treatment. The recovery should mirror Optimal's recommendation for lost revenues: as a separate expense recovered annually.

With Enbridge's current performance incentive, earnings are structured like a markup on expenditures.[25] For example, in its proposed DSM Plan, in 2023 Enbridge budgets $142 million for the DSM portfolio and sets aside a maximum performance payment of $19.89 million. Based on historic performance, Enbridge is likely to earn less than the maximum, so might instead receive an incentive of around $11 million. With expense cost recovery, Enbridge would then charge customers $153 million and capture the $11 million markup as pre-tax earnings.

Optimal's approach delays earnings by spreading them out over the amortization period, reducing their value in present value terms. While the amortization calculations usually exactly compensate for this delay (through the cost of capital adjustments), those adjustment only makes investors whole if the cost of capital inputs match the investor's discount rate. But in this case, the original $11 million was not raised in capital markets mixing debt and equity; it came entirely from shareholders who are due their full 9% after-tax returns. If, performance incentives are recovered along with other portfolio expenditures, the cost of capital used to calculate revenue requirements will be somewhere between Enbridge's WACC (consistent with my recommendation) and Enbridge's cost of debt (per Optimal's recommendation), both far below 9%. Depending on the cost of capital and term applied, this differential reduces shareholder earnings between 4% and 27%, in present value terms.

This change in cost recovery for the performance incentive also vastly decreases the magnitude of performance earnings showing up on Enbridge's books, at least in the short term. With amortization, DSMI earnings will drop from around $8 million in after-tax earnings, as booked over the last few years, to between $1 million and $3 million in 2024, again depending upon the cost of capital and term approved by the OEB. While these values will rise in future years, this immediate drop would send the wrong signal to Enbridge management and shareholders about the premium the OEB places on DSM.

Finally, I believe Optimal's recommendation will create additional accounting and tax issues that will need to be resolved to ensure that shareholders receive the full value of the performance incentive (or,

[25] Enbridge's structure can be thought of as profit model driven by net margin—like those charged by service businesses—rather than a profit model driven by return on investment—like those charged by capital intensive businesses.

depending on the treatments, that customers are not overcharged). I am not an accountant, but I believe Optimal's recommendation raises issues about how to properly calculate and book amortization and tax charges that would need to be addressed.

In summary, I think that Optimal's recommendation to recover the performance incentive by amortizing it along with other program expenditures creates a number of problems, and should be rejected. Instead, I recommend that Enbridge recover its full performance incentive with expense treatment, continuing historic treatment of Enbridge's DSMI, and consistent with Optimal's recommendation for lost revenues.

2.2.4. Response to Specific Amortization Inputs

If the OEB decides to use amortization for Enbridge's DSM cost recovery, my recommendations differ from Optimal's regarding the cost of capital and term to use in the amortization calculations.

2.2.4.1. Cost of Capital

As described in Section 1.2.1, Optimal recommends the OEB set the cost of capital to the cost of debt. I recommend instead that the OEB set cost of capital to the WACC approved by the OEB in Enbridge's annual rate proceeding.

In its report, Optimal provides little empirical or theoretical support for its recommendation.

Optimal provides no empirical comparisons to other jurisdictions using this approach. As I showed in Table 4, none of the 13 jurisdictions covered in the Optimal report apply the cost of debt in amortization structures. Most jurisdictions apply the WACC approved in utilities' most recent rate cases (as does British Columbia, which was not include in Optimal's report). Those few utilities that structure performance incentives as adjustments to utility ROE, apply those adjustments to the same base cost of capital applied to other rate base assets.

Similarly, Optimal offers little theoretical support for its recommendation, limited to statements that creditors should feel some security that costs will be recovered, i.e.: "…there is an extensive stakeholder process to develop, review and approve program budgets that are then approved by OEB. This process ensures an extremely low risk that program expenditures will not be recovered. Further, the amortized balance will be approved annually and become a regulatory asset, further ensuring security to any potential lender."[26]

These statements seem to conflate recovery of *any costs* with the actual requirements of investors, which is the recovery of *enough costs* to provide a fair rate of return. While a stakeholder process may increase investor confidence that DSM costs will enter rate base, this minimal assurance will not be enough to attract the investments required to fund the Enbridge DSM portfolio.

As I showed in Figure 4, investments required for amortizing Enbridge's current budget trajectory (even without further increases that could be allowed through amortization) could exceed $1 billion within a decade. As I showed in Table 2, Enbridge pays its investors a WACC of approximately 5.8%, including 4%

[26] Optimal Report, page 16.

interest for bondholders and 9% return on equity for shareholders. I don't see how Enbridge could raise a billion dollars by promising investors only 4% returns.[27] Those investors would instead shift their funds to other gas utilities earning their full authorized costs of capital.

If Optimal believes that Enbridge could somehow finance its DSM funding *solely* through bond investors, I don't understand how this could work in Ontario. It is my understanding that the OEB directs Enbridge to maintain a capital structure including 36% equity. If Optimal thinks Enbridge could somehow dedicate a bond raise to support the DSM portfolio, this would have the impact of skewing the capital structure, and it would force Enbridge to increase equity to maintain the OEB's guidance on capital structure.

Optimal also seems to imply that the performance incentive might be enough to compensate Enbridge shareholders for the lack of fair returns provided with the low amortization cost of capital. They state in their report: "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."[28]

I think this approach is problematic for multiple reasons. First, by financing amortization at only the cost of debt, Optimal's approach penalizes Enbridge shareholders for the capital they supply to fund the DSM portfolio. These penalties more than offset payments Enbridge would receive from performance incentives, and so combined returns will drop below Enbridge's 9% authorized ROE. For example, I calculate that, at target performance levels, performance incentives will provide shareholders a combined ROE of only around 6% at the 16-year amortization term proposed by Optimal.

As I discussed in Section 2.2.3.3.1, the OEB should separate the performance incentive from the returns required by investors to fund the capital to finance the portfolio. A well-structured approach will reimburse investors for their cost of capital in financing the portfolio, and then use the performance incentive to provide premium returns that give Enbridge incentives to prioritize DSM over other investment and management opportunities, and also to improve portfolio performance. Optimal's proposal instead provides inferior returns for financing the portfolio, and then dismantles the performance incentive by repurposing it to try and make up losses on the portfolio financing. I think this approach will severely limit Enbridge's ability to raise the capital needed to fund the portfolio.

I also note that Ontario does not have legislation existing in other jurisdictions that requires Enbridge to deliver DSM programs. Enbridge's management decision to provide DSM programs is voluntary, and so using the performance incentive as an inducement to utility management is even more critical.

Since Optimal offers no empirical support and only weak theoretical support for its recommendation to finance amortization at the cost of debt, the OEB should reject this recommendation. Instead, if the OEB decides to implement amortization, the OEB should apply the WACC approved in Enbridge's annual rate proceedings. This approach is consistent with the approach in every other jurisdiction in North America

[27] Note that Optimal's original recommendation to award only short-term debt costs (from its original report provided as evidence on December 1) would have resulted in *negative* equity returns.
[28] Optimal Report, page 3.

that recovers DSM expenditures with amortization. This approach is also consistent with how Ontario and other jurisdictions compensate utilities for the cost of capital they incur to finance long term supply assets like pipelines and power plants.

2.2.4.1.1. Regulatory Asset Risk

As I discussed in Section 2.1.1.2, the regulatory asset created by amortizing DSM expenditures is not as valuable or secure as physical assets like power plants or pipelines. For this reason, an argument could be made that even fully compensating Enbridge for its authorized ROE might not be enough to attract capital.

Physical assets confer ownership to the utility; in cases of financial stress, those owned assets can be sold or otherwise collateralized to create financial resources. Enbridge's DSM investments create physical assets that are owned not by Enbridge, but instead by customers—the families and business who participate in Enbridge's programs—and so confer no ownership benefits to Enbridge.

Many investors and bond rating agencies also perceive regulatory assets as being riskier than physical assets, with fears that a future OEB Panel might not honor the entire revenue obligations required to fully compensate investors. As discussed in Section 2.1.1.2, this is especially true if a future OEB Panel would decide to stop funding ongoing DSM programs. If this were to happen, the OEB would need to continue charging customers for past investments in order to make investors whole, even though Enbridge would no longer be providing DSM services. While the current OEB Panel clearly supports DSM, investors are aware that legislators and regulators in Ohio, New Hampshire, and other jurisdictions have changed course and greatly reduced DSM funding in recent years.

Concerns over the magnitude of regulatory asset balances have also been a key issue in Maryland, where DSM programs are ongoing and expenditures have been amortized for over a decade. A committee of utilities and stakeholders has been meeting since 2018 in attempts to address DSM regulatory assets that were projected to exceed $US 900 million ($C 1.1 billion) statewide.[29] The group could not reach consensus on approaches for drawing down the asset balances, primarily due to the large rate increases required to a shift from amortization to traditional expense treatment.[30]

2.2.4.2. Term

As described in Section 1.2.1, Optimal recommends that the OEB set the amortization term to the "average measure life of a typical efficiency portfolio", that is, the typical WAML for measures installed by the Enbridge portfolio, which, as I noted in Section 2,2,1, is approximately 16 years. Optimal also suggests that a shorter term might make sense as a compromise.

I agree with Optimal that tying the amortization term to the portfolio WAML can make good economic and policy sense, in that it matches the cost recovery period to the period over which installed measures provide benefits to program participant and the utility system as a whole. I also agree with Optimal that

[29] Occulus CAS, LLC. *Empower Program Cost Analysis.* Prepared for the Maryland Energy Administration. October 15, 2020.
[30] As a result of this process, Maryland has shifted costs for behavior programs and some administration costs to expense treatment.

a shorter term might be appropriate. As I described in Section 2.1.2, shorter terms reduce long term rate impacts on customers and also reduce risks associated with unamortized asset balances on investors. On the other hand, shorter terms increase rates in the near term, and therefore will accommodate smaller portfolio budget increases before running into the OEB's historic guidance on rate impacts.

As I showed in Table 3, most other jurisdictions in North America apply terms of 5 or 10 years. As I discussed in Section 1.2.4.1, given the potential long-term regulatory risks facing the natural gas industry, I recommend that, if the OEB decides to implement amortization, it apply 5-year terms.

2.2.5. Response to Discount Rate Discussion

As discussed in Section 2.2.1, Optimal recommends that the analysis of amortization as a cost recovery model apply "a reasonable discount rate", and has suggested that a 10% discount rate faced by many customers might be appropriate[31]. In their report, Optimal provides a number of examples to illustrate how customers could receive long term savings, in present value terms, with amortized cost recovery.

As a mathematical exercise, I don't disagree with Optimal's conclusion that customers with discount rates higher than the cost of capital applied in the amortization calculations will accrue savings in present value terms. However, I disagree with the broader policy conclusion that the use of customer discount rates represents a reasonable framework for evaluating DSM in Ontario.

2.2.5.1. Present Value Savings with Customer Discount Rate

The examples provided in the Optimal report are analogous to an investor able to borrow money at, say 5.8%, or Enbridge's cost of capital, and then investing those funds in an opportunity providing returns at, say 10%, or the customer's discount rate. That investor will always be better off in present value terms, and will always earn a positive net rate of return reflecting the arbitrage spread between the two rates. That is straightforward math.

I showed a similar analysis in in Section 2.1.1. However, my example used Enbridge's discount perspective, rather than a customer's. In my example, Enbridge funds the DSM investments with its capital resources costing 5.8%, and is then repaid through the amortized cost recovery structure applying the same 5.8% cost of capital. With this approach, after capturing all the cash flows out through 2052, Enbridge receives revenues, in present value terms, that exactly equal its initial investments. That is, the cumulative NPV of the cash flows to Enbridge is zero, and Enbridge earns exactly its authorized WACC with this cost recovery structure.

Figure 13 shows the same data I provided earlier in Figure 3, comparing expensed and amortized cost recovery of portfolio expenditures occurring out through 2042. Consistent with Figure 3, this example calculates amortized cost recovery using a 10-year term and Enbridge's WACCC. Figure 13 adds lines showing the cumulative net present value of the difference between the two approaches from Enbridge's perspective and also from the perspective of a customer with a 10% discount rate.

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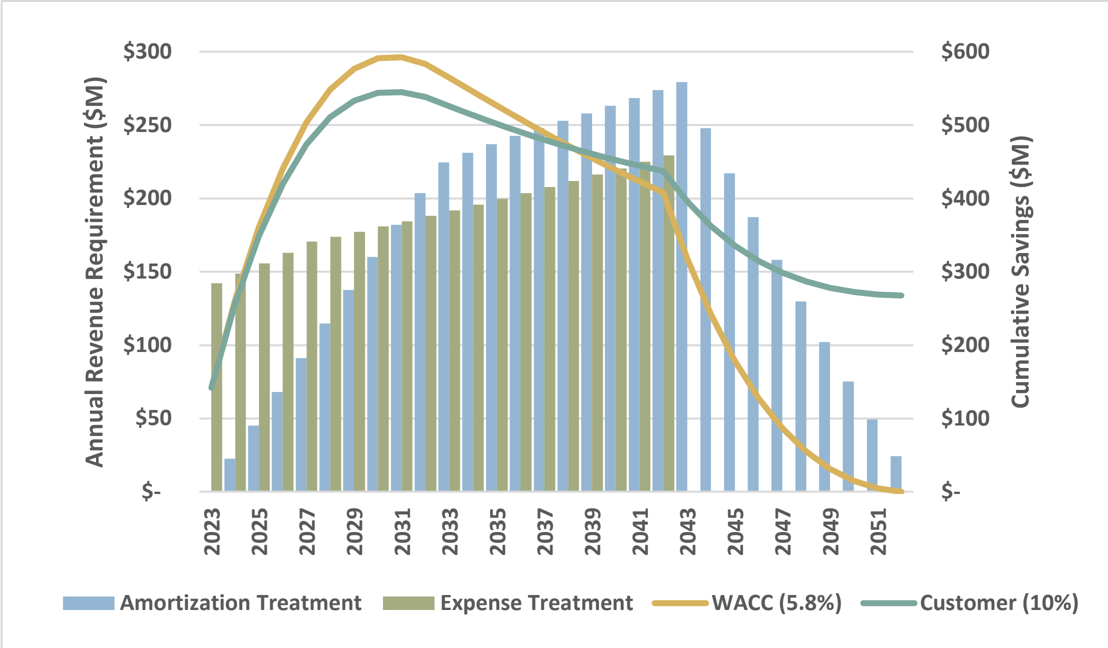
[31] IRR response to 7-EGI-8-OEB Staff.1c.

Figure 13: Cumulative NPV Savings from Amortization



From Enbridge's perspective, the cumulative net present value reaches zero by 2052, after ongoing portfolio investments stop in 2042, but with revenue continuing through 2052 in order to pay off all unamortized asset balances. Again, this is straightforward math, and reflects basic utility rate design. By attracting investment resources at 5.8%, and then being repaid over time at 5.8%, Enbridge's discounted cash flow is zero, and it earns exactly its authorized WACC.

From the customer's perspective, discounted cash flows exceed zero throughout the analysis. Again, this is straightforward math, analogous to the investor borrowing at 5.8% to make investments at 10%. This result is similar, but not identical to the charts provided in Optimal's report. My analysis stops new investment in 2042, and then continues revenues through 2052 to fully repay all the investments made within the analysis horizon, while Optimal ignored these end effects. However, even when properly valuing these end effects, my conclusion is the same as Optimal's: when valued at the customer's discount rate, as long as that discount rate is above the cost of capital applied in the amortization structure, amortization will always provide long term savings compared to expense treatment, on a present value basis.

Optimal points out in a footnote within their report that they ignore these end effects.[32] While this oversight does not impact the overall conclusion in this one application, as a rule, ignoring end effects can lead to poor decisions. For example, what if Enbridge evaluated the cost effectiveness of its DSM portfolio by comparing costs and benefits only through 2027, without the capturing the additional benefits accruing from measure installations throughout their useful lives? Within that limited

[32] Optimal Report, footnote 11 states: "This assumes a steady state of program funding. If spending stops, the early benefits from amortization would start to decrease as the utility needs to pay off the amortized payments from past program years."

timeframe, costs would exceed benefits, and that result might lead policy makers to recommend against investing in DSM. That would be a bad decision, informed by bad analysis.

2.2.5.2. Discount Rates for Amortization Analysis

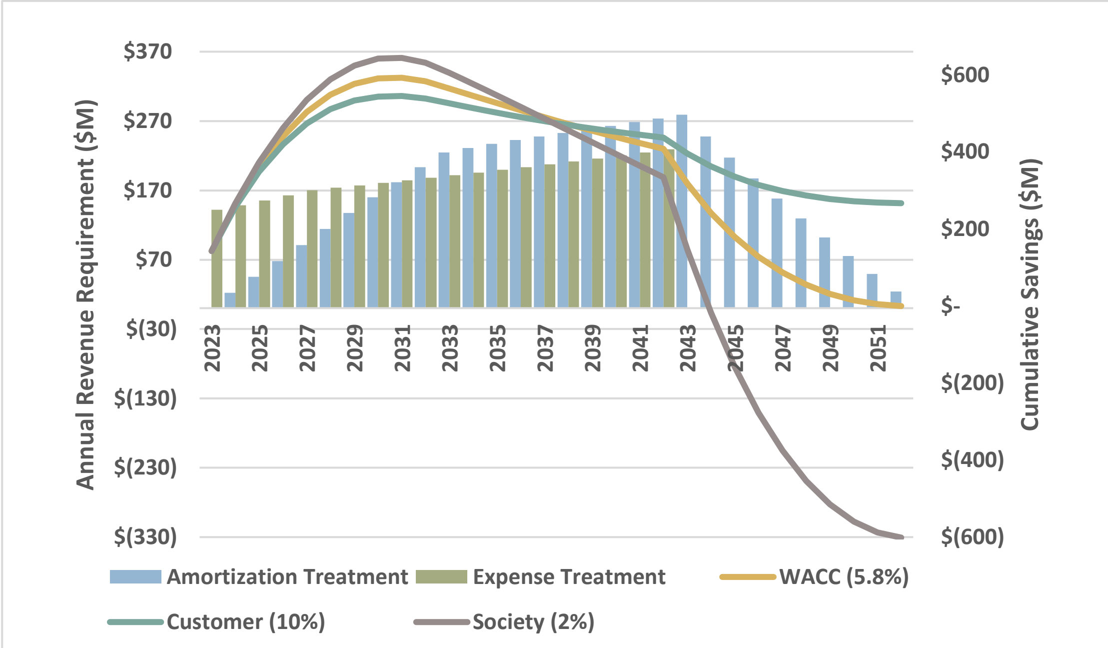
For similar reasons, I disagree with the broader policy conclusion that customer discount rates provide a reasonable framework for evaluating Ontario's DSM policies, whether those policies address cost recovery policy or DSM cost-effectiveness. If Enbridge evaluated cost effectiveness using a higher, customer discount rate, many measures and programs currently delivered through the portfolio could be eliminated. The resulting portfolio would provide far fewer benefits to Enbridge customers, far smaller reductions in carbon emissions, and might not be delivered at all.

To the contrary, some parties in this proceeding recommend Enbridge apply a low, societal discount rate to evaluate measures and programs. For example, EFG recommends Enbridge apply a real discount rate of 0.5%, consistent with nominal societal discount rates of 0% to 3% used in other jurisdictions.[33] Figure 14 shows that, when the cumulative NPV savings analysis incorporates a nominal discount rate of 2%, cumulative savings actually drop far below zero when all end effects are captured. With this discount rate framework, the amortization is more expensive on a present value basis, which would be an argument *against* using it for cost recovery.

In the end, I'm not sure discount rates are critical for the OEB in thinking about amortization. Regulators often balance competing objectives like economic efficiency, fairness, and gradualism in setting utility policy. DSM investments in Ontario are clearly economically efficient, and so, in my view, the OEB should focus on how to balance the additional DSM investments against the potential for higher rates in the short and long term, and against higher risks from regulatory assets.

[33] EFG report, page 41.

Figure 14: Cumulative NPV Savings from Amortization



3. PERFORMANCE INCENTIVES

In this section, I summarize Enbridge's DSM performance incentive proposal and describes alternative recommendations from Optimal and EFG. I then propose a compromise for the OEB's consideration that adjusts Enbridge's proposal by adopting some features recommended by Optimal and EFG.

3.1. Enbridge Performance Incentive Proposal

Enbridge's performance incentive proposal extends a mechanism that has been in place throughout the 2015-2020 DSM Plan, and now extended through 2022. Enbridge's proposal keeps key features of the current mechanism, and incorporates new features recommended by the OEB in its letter on a Post-2020 DSM Framework.[34] as well as features recommended by stakeholders during the OEB's Mid-Point Review[35]. Enbridge's full performance incentive proposal is outlined in Schedule D of its Proposed DSM Plan.[36]

3.1.1. Performance Incentive Components

Enbridge divides the performance incentive mechanism into four main components, with one component broken into two important subcomponents:

- ***Annual Scorecard Achievement*** provides annual awards for meeting performance metrics assigned separately to 7 separate program groups:
  - ***Resource Acquisition Programs*** include 5 program groups (Residential, Low Income, Commercial, Industrial, and Large Volume).
  - ***Multi Year Programs*** include 2 market transformation programs (Energy Performance and Beyond Building Code).
- ***Annual Net Benefits Shared Savings*** provides annual awards that are a share of the net benefits generated by portfolio investments each year.
- ***Long Term Scorecard Achievement*** provides periodic awards (after the second and fifth years) for meeting performance metrics for the Low Carbon Transition program, which is also a multi-year, market transformation program.
- ***Long Term GHG Achievement*** provides a one-time award (after five years) for meeting a long-term greenhouse gas (GHG) savings target.

3.1.2. Maximum Performance Incentive Payments

As shown in Table 5, Enbridge's proposal defines maximum incentive payments over the 5-year plan period totaling $110.5 million, and average incentive payments of $22.1 million per year. Enbridge calculated the 5-year total by escalating the $20.9 maximum annual incentives defined in the OEB'S 2015-2020 Policy Framework (and then extended through 2022) for inflation out through the plan period.

[34] EB-2019-0003, OEB Letter Post-2020 Natural Gas Demand Side Management Framework (December 1, 2020).
[35] Mid-Term Review Stakeholder Meeting, Presentation by Environmental Defence and the Green Energy Coalition (September 6, 2018).
[36] EB-2021-0002, Schedule D, Tabs 2 through 4.

Table 5: Performance Components and Maximum Incentive Levels

	2023	2024	2025	2026	2027	5-Year Total	5-Year Average	% of Total
Annual Maximum Incentives (millions)								
Annual Scorecards								
Resource Acquisition	$12.1	$12.3	$12.6	$12.8	$13.1	$62.8	$12.6	56.8%
Multi Year	$1.2	$1.2	$1.2	$1.3	$1.3	$6.2	$1.2	5.6%
Annual Net Benefits	$6.6	$6.8	$6.9	$7.0	$7.2	$34.5	$6.9	31.2%
Subtotal Annual	***$19.9***	***$20.3***	***$20.7***	***$21.1***	***$21.5***	***$103.5***	***$20.7***	***93.7%***
Long-Term Maximum Incentives (millions)								
Low Carbon Transition		$0.8			$1.2	$2.0	$0.4	1.8%
GHG Reduction					$5.0	$5.0	$1.0	4.5%
Subtotal Long-Term	***$0.0***	***$0.8***	***$0.0***	***$0.0***	***$6.2***	***$7.0***	***$1.4***	***6.3%***
Total Portfolio	**$19.9**	**$21.1**	**$20.7**	**$21.1**	**$27.7**	**$110.5**	**$22.1**	**100%**
Portfolio Budget (millions)								
Total Portfolio Budget	$142.3	$148.8	$155.7	$162.9	$170.5	$780.2	$156.0	
Max Incentives as % of Budget	14.0%	14.2%	13.3%	13.0%	16.3%	14.2%	14.2%	

Enbridge then allocated the maximum incentive pool among the various components. Beginning from the $110.5 million 5-year totals, Enbridge allocated:

- $7 million for long-term performance incentives
  - $2 million to ***Low Carbon Transition***
  - $5 million to ***GHG Reduction***
- Of the remaining $103.5 million:
  - Two-thirds to ***Annual Scorecards***, or $69 million across the five years
  - One-third to ***Annual Net Benefits***, or $6.2 million across the five years

Enbridge further allocated the ***Annual Scorecard Achievement*** incentive pool among the various program groups. For some groups, Enbridge further allocated incentives to key markets within the groups. Enbridge allocates Low Income to single-family and multifamily markets; Commercial to large- and small-customer markets; and some Multi Year programs to residential, low income, and commercial markets (depending on the program).

3.1.2.1. Incentive Allocations to Programs and Sub-Markets

Enbridge did not allocate maximum incentives in direct proportion to projected program budgets or savings, but instead defined allocations that "provide a clear well-balanced inducement for the Company to focus efforts across all sectors and proposed programs"[37]. That is, Enbridge overallocated the incentive pool (relative to savings targets) to hard-to-reach markets, including low-income, residential, multifamily, and small commercial markets, and under allocated incentives to large commercial, industrial, and large volume customers. Enbridge also allocated some incentive pool to the

[37] EB-2021-0002, Exhibit D, Tab 1, Schedule 2, Page 5 of 16.

Multi Year programs, which pursue market transformation program designs with low initial savings, but longer-term portfolio benefits.

Enbridge's allocating approach is unique, as EFG noted in their report, stating: "The Company's proposal to have separate savings metrics for five different customer groups plus a sixth for one particular program is definitely unusual and probably unique. Indeed, we are unaware of any utility with savings and/or economic benefits metrics for which shareholder incentives can be earned that are subdivided to this degree."

I agree with EFG and know of no other utilities using this approach. I also find it a creative, innovative solution to tensions that arise with incentive mechanisms in other jurisdictions. As I will discuss in Section 2.4, performance mechanisms often struggle to balance competing objectives, on the one hand, incentivizing utilities to increase savings and drive up cost effectiveness, while also requiring utilities to serve more difficult and expensive hard-to-reach markets. Other jurisdictions address this tension by adding minimum spending requirements or countervailing metrics to ensure utilities maintain focus on hard-to-reach customers. However, these additions add complexity to the mechanisms, making portfolio management more difficult, and often leading to unintended consequences.

Enbridge solves this tension by using the incentive allocations to adjust the price signal to portfolio managers to maximize performance incentive, compared to the prices embedded in the raw portfolio costs and savings. For example, Enbridge allocates incentives to Low Income programs that are approximately three times their savings share. Effectively, Enbridge has tripled the value of those savings in Enbridge's performance incentive, increasing Enbridge's incentive for shifting resources into this hard-to-reach market. The allocations don't totally offset price differences among the programs, and so allows Enbridge to continue to be rewarded for shifting costs from high- to low-cost options (and thereby maximizing portfolio savings and cost-effectiveness).

By allocating incentives to individual program groups and markets, and setting performance targets for individual offerings, Enbridge's mechanism further encourages it to allocate resources across all sectors and programs. If Enbridge eliminates budgets for individual offerings, or shifts emphasis below minimum performance thresholds, it foregoes the incentive pool allocated to that offering.

Enbridge has created an elegant feature that addresses multiple planning objectives without the need for setting additional minimum budgets or countervailing metrics. However, their approach also adds constraints to their flexibility in managing the portfolio, which makes it harder for them to maximize incentive payments, compared to other utilities.

3.1.3. Performance Metrics

Performance metrics vary by component:

- For ***Annual Scorecard Achievement***:
    - ***Resource Acquisition Programs*** are measured against net annual gas savings.

  - ***Multi-Year Programs*** are measured against annual market transformation metrics, which are mostly participation targets for customers and market actors, but also include a net annual savings metric for the Energy Performance Program.
- ***Annual Net Benefits*** provides annual awards calculated as a share of the net present value of Total Resource Cost Plus (TRC-Plus) net benefits generated by portfolio investments.
- ***Long-Term Scorecard Achievement*** for the Low Carbon Transition program is measured against market transformation metrics (participation targets for customers and market actors).
- ***Long-Term GHG Achievement*** is measured against 5-year GHG savings generated by the portfolio, calculated as gross gas savings multiplied by a GHG intensity factor and by five years.

3.1.4. Performance Targets

For the ***Resource Acquisition*** scorecards, Enbridge defines net annual savings targets for 2023 for each program group and key market. For the ***Multi-Year*** and ***Long-Term*** scorecards, Enbridge defines market transformation targets for 2023 and 2024 for each program and key market. Enbridge also defines a process for updating scorecard targets through 2027, including a Target Adjustment Mechanism (TAM) and a Mid-Point Assessment.

The ***Annual Net Benefits*** component isn't measured against a target, but instead awarded directly through the shared savings mechanism. Savings shares are calculated on a marginal basis, with no share for benefits below $100 million; a 1% share the second $100 million, 1.25% share for the next $100 million, and then continuing in $100 million increments until reaching a maximum share of 2.50% for all benefits over $500 million.

The ***Long-Term GHG*** target is calculated as portfolio-wide gross gas savings for 2023 multipled by the gas intensity factor, then multiplied by 5 years, and then increased by a 15% stretch factor.

3.1.5. Performance Thresholds

Performance thresholds represent the levels of performance required to receive the maximum performance incentive, as well as payments provided at other performance levels. Performance thresholds vary by component.

For the ***Resource Acquisition, Multi-Year***, and ***Long-Term*** scorecards, maximum incentives are paid for reaching 150% of scorecard targets. Half of maximum incentives are paid at 100% of targets, and no incentives are paid at 50% of target. Incentives are interpolated for performance between these points. Since the performance thresholds are symmetrical around the 100% target, there is no interpolation inflection across the entire performance band.

For ***Annual Net Benefits***, the marginal share structure sets a floor and pays no incentives below $100 million in net benefits. The maximum incentive pool of $6.9 million per year (on average) sets the ceiling. For example, in 2023, the $6.63 million incentive pool is awarded for net benefits of $535 million. (The value varies from year to year.)

In contrast to the scorecard components, where performance bands create a linear relationship between performance and incentive, the share assignments accelerate incentive payments as net benefits increase. EFG calculates in its report the portfolio savings required to hit the minimum and maximum incentive awards.[38] In 2023, compared to the $372 million in net benefits projected for Enbridge's 2023 portfolio savings target, the $100 million floor represents 27% of Enbridge's projected net benefits, and the $535 ceiling represents 144% of Enbridge's projection. By 2027, EFG estimates that these values will shift, and Enbridge will pass the floor at 21% of its portfolio savings target and reach the ceiling at 112% of target.[39]

For ***Long-Term GHG*** Enbridge receives the maximum incentive if it meets the GHG stretch performance target. Enbridge receives no further incentive for exceeding the target, and no incentive at all if performance falls below the target.

3.1.6. Performance Incentive Management Process

Enbridge's proposed DSM Plan and related Policy Framework includes five elements that help it manage the performance incentive process. The key management elements include:

- The Target Adjustment Mechanism (TAM), which extends an annual process in place since 2012, adjusts targets for key changes occurring between the time the plan is developed and the year the programs are delivered. The TAM incorporates changes from evaluation results, other key market changes, inflation, and Enbridge's productivity in delivering the programs.
- The Mid-Point Assessment, which creates a streamlined review and update of the portfolio midway through the cycle, and could result in shifts to portfolio budgets and savings targets. In particular, Enbridge will use the Mid-Point Assessment to create targets and budgets for some multi-year programs for 2025-2027. The Mid-Point Assessment could also result in adjustments to the Performance Incentive Mechanism.
- The flexibility to direct budget resources to improve portfolio performance. This policy allows Enbridge to shift budgets away from underperforming programs and towards programs with stronger performance. These budget shifts increase portfolio savings, and thereby portfolio cost effectiveness. They also improve performance against metrics driving the performance incentive. However, Enbridge is limited to shifts that do not increase or decrease program budgets by more than 30%.[40]
- Ring fence budgets for the Low Income and Low Carbon Transition programs, which ensure that "no program funds budgeted for each of these programs will be transferred to any other program"[41], and returns to customers any under spending for these programs.
- The DSMVA treatment that allows Enbridge to exceed portfolio budgets by up to 15% when it achieves at least 100% of scorecard targets for that class.[42]

[38] EFG Report, page 28.
[39] I have not verified EFG's 2027 estimates, but provide them here for illustration.
[40] EB-2021-0002, Exhibit C, Tab 1, Schedule 1, Page 15 of 66.
[41] EB-2021-0002, Exhibit D, Tab 1, Schedule 1, Page 16 of 26, Plus Attachment.
[42] EB-2021-0002, Exhibit C, Tab 1, Schedule 1, Page 51 of 66.

3.1.7. Summary of Enbridge Proposal

Table 6 summarizes the key features of the Enbridge Proposal. Note that the table relies on EFG's estimates of performance thresholds for the net benefits component. While I don't endorse those specific values, I include them here for illustration.

Table 6: Summary of Enbridge Performance Incentive Proposal

Component	Metric	Sub-Target	Frequency	5-Year Incentive Payment ($M)			Threshold (% of Proposed Plan)	
				Max		Share	Min	Max
Annual Scorecards: RA*	Net Annual Savings	7 Sub-Targets	Annual	$	62.8	57%	50%	150%
Annual Scorecards: MY#	Participants	8 Sub-Targets	Annual	$	6.2	6%	50%	150%
Net Benefits	TRC+ Net Benefits		Annual	$	34.5	31%	21%-27%	112%-144%
Low Carbon Transition	Participants	4 Sub-Targets	Year 2, 5	$	2.0	2%	50%	150%
GHG Reduction	5-Year GHG Savings		Year 5	$	5.0	5%	0%	115%
Total				**$**	**110.5**	**100%**		
Total as % of Budget					**14.2%**			

*RA=Resource Acquisition
#MY=Multi Year

Performance Incentive Management Process:
- Performance targets adjusted through TAM and Mid-Point Assessment
- Ring-fenced budgets for Low Income and Low Carbon Transition programs.
- Flexibility to move budgets among programs and measures within rate classes.
- DSMVA allows 15% budget increases witin rate class.

3.2. Optimal Performance Incentive Proposal

Optimal provides 17 recommendations for the OEB to consider regarding performance incentives. In this section, I summarize those recommendations, but defer reference to Optimal's arguments supporting these recommendations until I discuss my compromise proposal in Section 2.4.

3.2.1. Performance Incentive Components

- Create "a main metric based on net benefits" for 70% of the incentive pool.
- Allocate 30% of the incentive pool to "a limited number of up to five 'countervailing metrics that are independent or actively harmful to net benefits, or simply align with critical policy goals."
- Consider "eliminating the Long-Term GHG Reduction Incentive".

3.2.2. Maximum Performance Incentive Payments

- Consider "establishing the overall performance incentive amount as a percent of net benefits, in advance of the planning process." However, Optimal makes no recommendation regarding the percentage that should be applied.

3.2.3. Performance Metrics

- Change net benefits calculation from the TRC-Plus perspective to the Program Administrator Cost plus Carbon (PAC-Plus) perspective.

- Create net benefit performance metric, analogous to Enbridge's other scorecard metrics, but tied to net benefit levels rather than savings or participation (as opposed to Enbridge's approach to calculate incentives directly as shared savings).
- Change metric for Energy Performance and Building Beyond Code programs from participation to gas savings.
- If the OEB maintains a gas savings goal, change metric from net annual savings to net lifetime savings.

3.2.4. Performance Thresholds

- Raise minimum thresholds to 75%.
- Lower maximum thresholds to between 110% and 125%.

3.2.5. Performance Incentive Management Process

- Eliminate TAM, including TAM adjustments to performance targets for evaluation changes, inflation, and productivity.
- Require annual PAC-Plus net benefits adjustment to counteract changes in avoided costs for natural gas and GHG.
- Allow savings target adjustments for evaluation changes during Mid-Point Assessment.
- If TAM is maintained, create minimum performance targets.
- Create "true multi-year approach, where budgets and targets are cumulative for the full 5-year plan period".
- Translate 5-year targets into "annual milestones" to calculate performance incentive each year.
- Allow "estimated and reported (and potentially unverified or evaluated) performance" calculations and reduce savings verifications "for well-established programs".

3.2.6. Summary of Optimal Performance Incentive Proposal

Table 7 summarizes the key features of Optimal's recommendations. Because Optimal does not make firm recommendations on specific metrics or incentive structures, it is difficult to fully summarize their proposal precisely, but Table 7 covers the key features.

Table 7: Summary of Optimal Performance Incentive Proposal

Component	Metric	Sub-Target	Frequency	5-Year Incentive Payment ($M) Max	5-Year Incentive Payment ($M) Share	Threshold (% of Proposed Plan) Min	Threshold (% of Proposed Plan) Max
Net Benefits	PAC+ Net Benefits		Annual	$ 77.4	70%	75%	110-125%
Countervailing							
Beyond Building Code	Net Lifecycle Savings	6 Sub-Targets	Annual				
Low Carbon Transition	Net Lifecycle Savings	4 Sub-Targets	Year 2, 5	$ 33.2	30%	75%	110-125%
Others TBD	TBD	TBD	Annual				
GHG Reduction	------ *Consider Eliminating* ------						
Total				**$ 110.5**	**100%**		
Total as % of Budget				**14.2%**			

Changes Recommended to Performance Incentive Management Process:
- Eliminate TAM..
- Performance targets adjusted through Mid-Point Assessment.
- Manage 5-year budgets..
- Set maximum incentive pool as percentage of net benefits.
-Simplify evaluation measurement and verification requirements.

3.3. EFG Performance Incentive Proposal

This section summarizes EFG's recommendations regarding performance incentives. I defer any references to EFG's support for the recommendations until discussing my compromise proposal in Section 2.4.

3.3.1. Performance Incentive Components

- Eliminate Annual Net Benefits component and reallocate incentive pool to other metrics.[43]
- Eliminate Energy Performance and Beyond Building Code programs and reallocate incentive pools to other savings metrics.[44]
- Change focus of Long Term GHG Reduction component to new effort aimed at improving systemwide customer energy intensity (e.g., gas use per household or unit of GDP).

3.3.2. Maximum Performance Incentive Payments

- Tie maximum shareholder incentive formulaically to the magnitude of energy savings proposed.[45] (EFG makes no specific proposal regarding formulaic relationship to be applied.)
- Maintain allocation of maximum payments to program group and sub-markets.

3.3.3. Performance Metrics

- Change Resource Acquisition scorecard metric from net annual to net lifecycle savings.[46]

3.3.4. Performance Targets

- Suggests that reasonable goals for energy intensity metrics might be 5% reductions in systemwide average residential and business intensities.

[43] EFG Report, page 30.
[44] EFG Report, page 25.
[45] EFG Report, pages 19-20.
[46] EFG Report, pages 22-23.

- Eliminate targets for gas heat pumps in Low Carbon Transition Program, but maintain targets for hybrid heat pumps.[47]

3.3.5. Performance Thresholds

- Raise minimum thresholds to 75%.[48]
- Lower maximum thresholds to 125%.[49]
- Maintain minimum thresholds of 50% for new endeavors with significant uncertainty and little track record.

3.3.6. Summary of EFG Performance Incentive Proposal

Table 8 summarizes the key features of EFG's proposal. Because EFG does not make firm recommendations in a few areas, it is difficult to fully summarize their proposal. But Table 8 covers the key features.

Table 8: Summary of EFG Performance Incentive Proposal

Component	Metric	Sub-Target	Frequency	5-Year Incentive Payment ($M)		Threshold (% of Proposed Plan)	
				Max	Share	Min	Max
Annual Scorecards: RA*	Net Lifecycle Savings	7 Sub-Targets	Annual	$ 103.5	94%	75%	125%
Low Carbon Transition	Hybrid HP Metrics	4 Sub-Targets	Year 2, 5	$ 2.0	2%	75%	125%
Customer Intensity	m3/house; m3/GDP	2 Sub-Targets	Year 5	$ 5.0	5%	75%	125%
Annual Scorecards: MY#	------	*Eliminate*	------				
Net Benefits	------	*Eliminate*	------				
GHG Reduction	------	*Eliminate*	------				
Total				**$ 110.5**	**100%**		
Total as % of Budget				**14.2%**			

*RA=Resource Acquisition
#MY=Multi Year
Changes Recommended to Performance Incentive Management Process:
- Set maximum incentive pool with formula tied to net lifecycle savings..

3.4. Compromise Proposal

Table 9 outlines my compromise proposal that captures key features from the Enbridge's proposal, as well as recommendations from Optimal and EFG proposal. I discuss each element of my proposed compromise in this section, and then summarize my recommendations in Section 3.5.

[47] EFG Report, page 31.
[48] EFG Report, page 26.
[49] EFG Report, page 26.

Table 9: Compromise Performance Incentive Proposal

				5-Year Incentive Payment ($M)		Threshold (% of Proposed Plan)	
Component	**Metric**	**Sub-Target**	**Frequency**	**Max**	**Share**	**Min**	**Max**
Annual Scorecards: RA*	Net Annual Savings	7 Sub-Targets	Annual	$ 102.3	93%	50%	150%
Annual Scorecards: MY#	Participants	8 Sub-Targets	Annual	$ 6.2	6%	50%	150%
Low Carbon Transition+	MT Metrics	4 Sub-Targets	Year 2, 5	$ 2.0	2%	50%	150%
Net Benefits	------	*Eliminate* ------					
GHG Reduction	------	*Eliminate* ------					
Total				**$ 110.5**	**100%**		
Total as % of Budget				**15.5%**			

*RA=Resource Acquisition
#MY=Multi Year

Changes Recommended to Performance Incentive Management Process:
- Maintain TAM.
- Maintain Mid-Point Assessment.
- Maintain ring-fenced budgets.
- Manage 5-year budgets.
- Maintain DSMVA 15% budget increases..
- Increase maximum incentive pool if savings targets increase.
- Simplify evaluation measurements and verification requirements.

3.4.1. Performance Incentive Components

My compromise proposal:

- Eliminates the Net Benefits and Long-Term GHG components and reallocates those incentive pools to the Resource Acquisition scorecards.
- Maintains the Annual and Long-Term scorecards for Enbridge's proposed Multi Year initiatives.
- Does not shift the Long-Term scorecard allocation to a new Long-Term Energy Intensity objective, as proposed by EFG.
- Includes multiple features that provide countervailing metrics, as proposed by Optimal.

3.4.1.1. Net Benefits Component

Enbridge crafted the Net Benefits component, in part, as a good faith response to stakeholder input during Mid-Term Review for the 2015-2020 DSM Plan. These comments called for a net benefit mechanism to provide Enbridge incentives to improve portfolio cost effectiveness by expanding savings within approved portfolio budgets. For example, EFG comments in the Mid-Term Review recommended that "options to incentivize the maximization of net benefits be considered as a priority issue in the development of the next DSM Framework."[50]

Optimal proposes its modified Net Benefits component, also with the objective of giving Enbridge a direct earnings incentive for improving portfolio cost effectiveness. EFG now advocates for eliminating the Net Benefits component, providing four reasons:

[50] In response to IRR 8-EGI-4-GEC.ED.1, EFG clarified that its comments were meant to distinguish between incentives for utilities to set higher goals versus incentives for utilities to manage goals once they are set.

- "Threshold for savings is too low".[51]
- "The value of net benefits can go up or down for reasons beyond utility control"[52], primarily, the value of avoided natural gas costs and carbon emissions.
- "Net Benefits metrics could undermine some savings metrics,"[53] primarily by giving Enbridge incentives to shift resources away from costly programs and measures to cheaper options. This is especially a concern for EFG regarding low-cost measures with short measure lives that contribute less to long term savings.
- "Increased complexity relative to energy savings metrics"[54] would drive up costs and contention associated with measuring inputs like electricity savings, water savings, measure costs, and avoided costs for electricity, water, natural gas, and carbon.

To be fair to the Enbridge and Optimal proposals, many of the issues EFG raises could be ameliorated with thoughtful redesign of the performance incentive mechanism. For example, the savings threshold could easily be increased without removing the entire Net Benefits component. And Optimal's recommendations to shift from a TRC-Plus to a PAC-Plus metric eliminates the need to estimate measure costs or electricity and water benefits. Optimal's recommendation to fix avoided costs throughout the plan cycle (or otherwise adjust plan goals) also addresses the volatility in natural gas and carbon prices.

But these potential solutions also add complexity. I generally agree with EFG that complexity should be avoided, and components should be limited to those necessary to align utility profit incentives with OEB policy objectives. Simpler mechanisms make portfolio managers' jobs much easier, by limiting the need to balance highly uncertain, competing performance metrics. And simpler mechanisms avoid unintended consequences that inevitably arise when these performance incentive mechanisms are initiated or changed.

I also disagree with the general premise that a Net Benefits component is necessary to encourage Enbridge to improve portfolio cost effectiveness. As EFG points out,[55] Enbridge's proposed incentive mechanism allows it to shift resources from costly programs and measures to cheaper options, although the important safeguards I outline in Section 2.1.6 limits this flexibility. These resource shifts, if executed thoughtfully, generate higher savings without increasing portfolio budgets. If Enbridge can deliver higher savings within available budgets, it will generate more net benefits from both the TRC-Plus and PAC-Plus perspectives. Thus, the performance mechanism, through the Resource Acquisition scorecards, already provide Enbridge a profit incentive to improve cost-effectiveness. In my view, a Net Benefit component adds complexity without substantially improving management incentives.

[51] EFG Report, page 27.
[52] EFG Report, page 28.
[53] EFG Report, page 28.
[54] EFG Report, page 30.
[55] EFG Report, page 29.

For this reason, in my compromise proposal, I shift the incentive pool for the Net Benefits component to the Resource Acquisition scorecards.

However, I also note that the Net Benefits component, by being measured at the portfolio level, provides Enbridge a hedge against the individual performance targets tracked in the Annual and Long-Term scorecards. Eliminating the Net Benefits component from my compromise proposal increases the risk that Enbridge will not achieve the full incentive payments. I address this further in Section 3.4.4, discussing performance thresholds.

3.4.1.2. Long-Term GHG Component

Enbridge crafted the Long Term GHG component as a good faith response to OEB direction to create longer-term savings targets separate from annual targets, outlined in the OEB's draft letter on a Post-2020 DSM Framework.[56]

Optimal and EFG both recommend eliminating the Long Term GHG component, stating that its metric, calculated from a sum of gross annual savings make it relatively easy to achieve. They also point out that by calculating applying a fixed GHG emission factor, the metric tracks gas savings, and so does not provide additional management incentives beyond gas savings.

To be fair to Enbridge, some of these issues could be addressed through changes to the metric and performance targets. For example, the metric could be shifted to a true lifecycle GHG target, by starting from net lifecycle gas savings rather than summing first-year gross savings and multiplying by 5. However, these solutions would still maintain a target that is colinear with gas savings targets in the Resource Acquisition scorecards. Again, since this adds complexity to the performance incentive mechanism, without substantially changing management incentives, I don't think it adds much value.

For this reason, in my compromise proposal, I shift the incentive pool for the Net Benefits component to the Resource Acquisition scorecards.

I again note that the Long Term GHG component, by being measured at the portfolio level, provides a hedge against the individual program performance targets. I address this further in Section 3.4.4, discussing performance thresholds.

3.4.1.3. Multi Year Components

My compromise proposal maintains the incentive allocations proposed by Enbridge for its Multi Year components, including annual scorecards for the Energy Performance and Beyond Building Code initiatives, as well as the Long-Term Low-Carbon Transition initiative.

EFG proposes eliminating the Energy Performance and Beyond Building Code programs entirely, and shifting Low-Carbon Transition to focus only on hybrid heat pumps, but maintaining it in the portfolio.

[56] EB-2021-0002, Exhibit D, Tab 1, Schedule 2, Page 15.

Optimal doesn't address the Multi Year Scorecards directly, but recommends changing the performance metrics for these initiatives. I address performance metrics in Section 2.4.3.

Obviously, if the OEB accepts EFG's recommendations and eliminates some offerings, those components should also be eliminated. However, evaluating the merits of those offerings is beyond the scope of my evidence in this proceeding.

In my compromise proposal, I assume the OEB approves these offerings, and so I maintain the Multi Year components as proposed by Enbridge.

3.4.1.4. Energy Intensity Component

EFG proposes shifting incentive allocated to Long-Term GHG Achievement to a new objective that would reduce systemwide customer energy intensity, tracking metrics such as cubic meters per home or per unit of business output. EFG provide examples of jurisdictions beginning to experiment with this approach.

Optimal provides similar references to these "non-programmatic performance metrics", but also notes the "significant challenges" associated with the approach. Optimal's primary concern is that outcomes are "generally influenced by a wide variety of factors, many of which are outside of the utility's control"[57], citing the particular challenge of controlling for the COVID-19 pandemic, which is likely to have large, uncertain, and ongoing influence on energy intensity.

For these reasons, I do not incorporate the Energy Intensity component in my compromise proposal. I also note that EFG's proposed performance targets of 5% reductions in energy intensity, would require Enbridge to reduce systemwide gas sales by 5%, or approximately 1.25% savings per year. These savings far exceed Enbridge's proposed savings targets, which is constrained by the OEB's historic limits on rate increases. If the OEB does adopt an Energy Intensity component, I recommend that performance targets can be reasonably achieved within the budget resources available to Enbridge.

3.4.1.5. Countervailing Metrics

Optimal proposes setting aside 30% of the incentive allocation for up to 5 components tracked with "countervailing metrics", but makes no proposal for specific components or performance targets. Optimal does suggest a number of options, including "comprehensiveness of savings…peak day reduction in supply constrained areas, percent of savings among low income or other hard to reach customers, participation among specific hard-to-reach sub segments, etc."[58]

As I described in Section 2.1, Enbridge's proposed incentive mechanism and portfolio design include multiple features that provide just the counterweight Optimal is trying to create with countervailing metrics. These features include:

[57] Optimal Report, page 26.
[58] Optimal Report, page 40.

- The ring fences on budgets for the Low Income and Low-Carbon Transition programs eliminate Enbridge's ability to shift resources from these priority programs to drive up savings or other profitable performance metrics.
- The 30% limits on transfers of funds among rate classes further limit Enbridge's ability to shift resources away from priority programs.
- The Annual Scorecard targets set performance metrics tied to individual program areas rather than one overarching savings target. This ensures that Enbridge must deliver services to all customers to access the entire incentive pool.
- The maximum incentive weights assigned to program groups overweight incentives for low income, residential, multifamily, and small commercial offerings, and underweight industrial, large commercial, and large volume offerings. As I discussed in Section 3.1.2.1, this weighting equalizes Enbridge's financial incentives across target groups, and so limits Enbridge's profit incentive for shifting funds from hard-to-reach markets.

For these reasons, I believe my compromise proposal actually achieves the objectives Optimal tries to accomplish with its countervailing metrics.

3.4.2. Maximum Performance Incentive Payments

In my compromise proposal, I maintain the maximum incentive payments of $105.5 million over the 5-year plan period, as proposed by Enbridge.

Optimal and EFG both suggest that the OEB consider tying maximum performance payments to portfolio outcomes like net benefits (Optimal's suggestion) or energy savings (EFG's suggestion). This approach would give Enbridge the incentive to propose larger portfolios creating, higher net benefits and energy savings.

Because we are already in the middle of this proceeding, with Enbridge already proposing a portfolio, it is unclear to me how these suggestions could work in the current proceeding. EFG acknowledges this and suggests that "this kind of approach could be put in place for the mid-term review as well as the next multi-year plan. It could even be adopted now if the Board agrees with our critique of the Company's proposed savings goals and instructs the Company to increase them."[59] I agree with EFG that, if the OEB does substantially increase portfolio budgets and savings goals—either in the current case, at the Mid-Point Assessment, or in the next plan cycle—that maximum incentive payments should also increase. In my view, Enbridge's profit incentive should be commensurate with the financial and management resources required to successfully execute the approved portfolio.

3.4.3. Performance Metrics

My compromise proposal maintains Enbridge's proposal to apply net annual savings metrics in its Resource Acquisition scorecards, while Optimal and EFG both recommend shifting back to the lifecycle savings metrics Enbridge employs in the current plan cycle. My compromise proposal also continues

[59] EFG Report, page 33.

Enbridge's proposal for tracking Multi Year scorecards using a mix of participation and savings metrics, while Optimal recommends shifting these to a natural gas savings metric.

3.4.3.1. Lifecycle vs. Annual Savings for Resource Acquisition Scorecards

I agree with both Optimal and EFG that the most important objectives achieved by Enbridge's portfolio align better with lifecycle savings than they do with annual savings. And I also agree that lifecycle metrics in jurisdictions like Michigan (as described in EFG's report[60]) and Illinois (where lifecycle savings are a key performance metric for natural gas utilities[61]) have been successful. And I am not opposed to lifecycle savings metrics in principle. However, I believe that Enbridge's recommendation for annual savings in this proceeding is reasonable and I recommend that the OEB approve it.

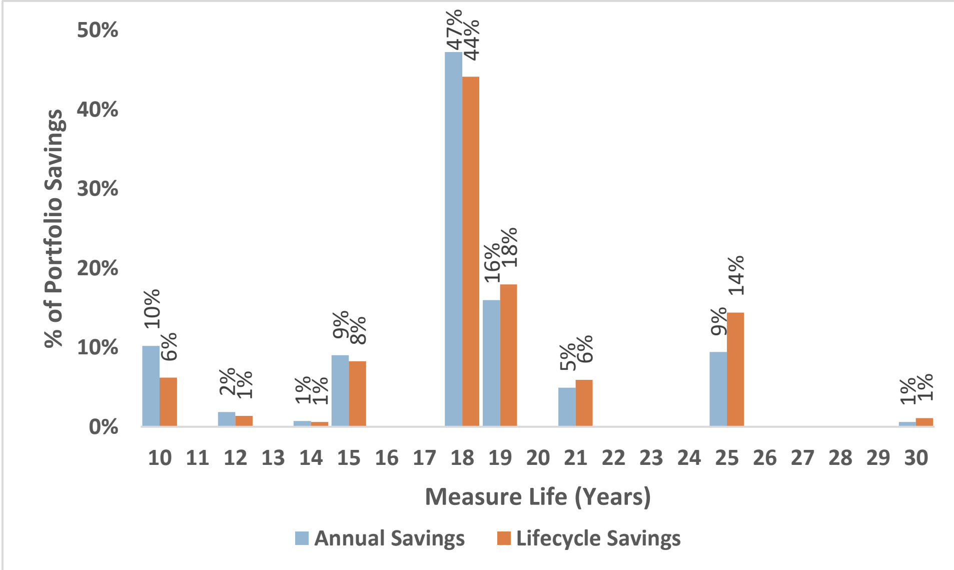
Optimal's and EFG's primary concerns are that annual savings metrics could encourage Enbridge to shift resources to short-lived measures that cost-effectively deliver annual savings, but also squeeze investment from longer-lived measures that are more cost-effective from the lifecycle perspective. This would misalign Enbridge's profit incentive with the portfolio's long-term objectives like reducing greenhouse gases. While this is hypothetically true, in fact Enbridge's portfolio includes few, if any, of these measures. Enbridge does not even offer the shortest-lived measures that can dominate gas portfolios in other jurisdictions like behavior modification programs, low-flow showerheads, and faucet aerators.

Figure 15 shows the distribution of annual and lifecycle savings among offerings of different lives in the Enbridge 2023 portfolio.[62] No offerings have lives below 10 years; in fact only one individual measure in the entire Enbridge portfolio has a life below 10 years. Only around 20% of savings come from offerings with lives below 18 years, and almost 70% of savings comes from offerings with lives between 18 and 22 years. In short, there is very little physical opportunity for Enbridge to shift resources from long-lived to short-lived measures; too much of the portfolio is clustered into lives of around 20 years.

An analysis of measure cost-effectiveness also indicates that there is even less *profitable* opportunity for Enbridge to shift resources to short-lived measures. The supply curves of annual and lifecycle savings, which rank offerings by cost per cubic meter saved, indicate that there is very little difference in the rank ordering when targeting annual versus lifecycle savings. That is, there are no short-lived offerings that are highly cost-effective from an annual cost perspective, but would squeeze investment from longer-lived measures. The supply curves are almost identical, and so shifts that improve annual savings have a proportional impact on lifecycle savings.

[60] EFG Report, page 23.
[61] *Nicor Gas Energy Efficiency Plan, January 2022-December 2025*. Illinois Commerce Commission Docket 21-0154, March 1, 2021.
[62] EB-2021-0002, Exhibit I.5.EGI.GEC.7, Attachment 1, Page 1 of 3.

Figure 15: Measure Lives for Enbridge Proposed DSM Plan



Finally, over 85% of the savings from the shortest-lived measures come from Large Volume customers. Because this program has smallest budget in the portfolio, Enbridge's 30% cap on funding shifts limits the funds that can be shifted into this program, and Enbridge's incentive allocations further limit the profit motive for Enbridge to even want to shift funds to this program.

In summary, Enbridge's portfolio and incentive mechanism designs limit its ability to profit from shifts to short-lived measures; there just isn't a very big earnings pool available from that strategy. Thus, while Optimal and EFG raise a theoretical concern, it poses little practical concern with Enbridge's actual portfolio.

On the other hand, I do have a practical concern with evaluation issues around measuring lifecycle savings. Converting from annual to lifecycle savings requires two calculations:

- One is a calculation multiplying annual savings by the equipment life. While this is straightforward, the data supporting equipment lives are poorly documented and rarely developed through actual measurements. This poses evaluation risks to Enbridge, when evaluators assign measure lives shorter than those Enbridge used to forecast lifecycle savings in its plan.
- Second, is a more complicated calculation of adjusting baselines for measures —like building insulation—with initial savings that change over time as underlying equipment—furnaces, in the insulation example—degrades or gets replaced with new, more efficient units. These calculations are far from straightforward and represent substantial evaluation risks to Enbridge when evaluators change assumptions from those Enbridge used to establish performance metrics.

It Is my understanding that Enbridge has already encountered these issues with its current performance incentive scorecards, and that experience is partly behind their proposal to change from lifecycle to annual savings metrics. I support this change, since the impacts on portfolio investment will be minor, and it can greatly lessen the time, costs, and frustration associated with coming to consensus on lifecycle savings results.

EFG recommends a similar approach issue within its performance incentive guiding principles: "There should be a preference for performance metrics that are comparatively easier to measure. Metrics must be sufficiently indicative of progress towards policy goals. However, it may be preferable to adopt a metric that is slightly less indicative of such progress than an alternative, but is significantly less difficult and/or less controversial to measure with reasonable accuracy."[63] I think this lifecycle savings issue falls squarely within EFG's guidance. While not a perfect metric, annual savings are basically colinear with lifecycle savings and so also correlate well with long-term objectives like GHG reductions and net benefits. They are also significantly less difficult and controversial to measure. I recommend that the OEB adopt annual savings as scorecard performance metrics, and include that approach in my compromise proposal.

Finally, I note that other jurisdictions have developed policies that effectively reduce controversy and evaluation risks associated with lifecycle savings calculations. These include using Technical Reference Manuals to clearly define measure lives and baseline adjustment rules; applying changes to lifecycle calculations only prospectively; limiting changes within plan cycles; and defining savings goals that automatically adjust within plan cycles when measure lives or baseline adjustments change. I recommend that Ontario adopt similar policies. If appropriate policies were adopted, then I could support using lifecycle savings as the performance metric for the Resource Acquisition scorecards.

3.4.3.2. Participation vs. Savings Metrics for Multi Year Scorecards

Optimal provides little support for its recommendation to use savings metrics for the Multi Year programs beyond the desire to "allow the OEB and stakeholders assurance that these programs are contributing to the overall objectives of DSM".[64]

I think this misses the point of market transformation as a strategy within a broad, mature DSM portfolio like Enbridge's. The goal of market transformation is to invest in relatively low-cost, early-stage market interventions that prime the market for new technologies and services with the potential to grow into large portfolio contributors in the future. These programs are not expected to deliver energy savings early in their program lifecycle. Early-stage activities include strategies like validating new technology performance and economics; training contractors to be able to support installations and maintenance; building market awareness with trade allies, consumers, and other market actors; and working with code officials to incorporate new technologies into standards with broad market reach.

These activities are not intended to generate large energy savings in the near term, but instead represent investments that bear fruit in future portfolios. Enbridge's proposed participation metrics rightly focus on the early market building activities that indicate early-stage success. Optimal's suggestion is analogous to a venture capital firm measuring startup performance only through profit

[63] EFG Report, page 20.
[64] Optimal Report, page vi.

metrics. The startup will only survive long enough to generate profits if investors allow founders to focus on necessary early-stage technology and market development tasks. Wise investors focus on non-financial metrics early in the business lifecycle, tracking the market progress necessary to grow from a startup into a profitable, ongoing concern.

I recommend the OEB approve Enbridge's use of participation metrics for their Multi Year initiatives. I have incorporated those metrics into my compromise proposal.

3.4.4. Performance Thresholds

My compromise proposal maintains the performance thresholds proposed by Enbridge for the Annual and Long Term scorecards, which set floors at 50% of target performance and ceilings at 150% of target.[65]

Optimal and EFG both recommend shrinking the performance bands, to floors of 75% and ceilings of 110%-125% (Optimal) or 125% (EFG). To support their recommendations, Optimal and EFG primarily cite other jurisdictions that apply these narrower thresholds.

It is important to note that these other jurisdictions apply thresholds at the portfolio level, while Enbridge applies thresholds for individual offerings. In other jurisdictions, utilities have broad flexibility to shift funds among offerings to increase portfolio performance and thereby maximize incentives. Utilities can maintain portfolio savings above 75% of target while allowing savings for individual offerings to fall below 75% without being penalized through the incentive mechanism. With Enbridge's mechanism, on the other hand, if floors were raised to 75%, Enbridge would be directly penalized for delivering portfolio savings above 75%, unless it also maintained savings above 75% for every program group; it cannot access the incentive pools allocated to each program group until it meets the threshold floors.

Compared to other jurisdictions, Enbridge also faces substantially more restrictions on its flexibility to move funds among offerings and rate classes. The constraints I discuss in Section 3.1.6 provide Enbridge substantially less room to shift budgets among offerings and rate classes, which makes it more difficult for Enbridge to reach 75% performance for each individual offering.

For these reasons, I think a 50% floor, with a symmetrical 150% ceiling, will properly align Enbridge's earnings opportunity with its ability to prudently manage portfolio resource allocations.

I also note that, in my compromise proposal, I ask Enbridge to give up the Net Benefits and Long Term GHG components, which represent over one third of the incentive payment allocation. These components, by being measured at the portfolio level, provided a hedge against individual program performance. By asking Enbridge to give up these components, I think it is also fair to ask Optimal and EFG to provide Enbridge additional flexibility through wider performance thresholds.

[65] Enbridge's proposal also allows performance ceilings for some submarkets to reach 200% of target, while maintaining ceilings for program groups set at 150% of target across all submarkets.

3.4.5. Performance Incentive Management Process

3.4.5.1. TAM Process

Optimal recommends eliminating the TAM and instead defining fixed performance targets that would no longer adjust annually through the TAM (but could be adjusted during the one-time Mid-Point Assessment).

I cannot support this change. The TAM allows Enbridge to evolve the portfolio in reaction to real-world changes in program markets and in the general economy. The TAM adjusts savings targets to reflect underlying changes to key evaluation parameters and inflation, which both affect the cubic meters of savings that Enbridge can reasonably save with available budgets. If the OEB were to set fixed targets today, based on Enbridge's current evaluation inputs and expectations for inflation, Enbridge would be accountable for changes to those assumptions, even though they are largely out of its direct management control. For example, a lower net-to-gross (NTG) assumption will make it harder for Enbridge to meet savings targets with available budgets, and penalize Enbridge through the incentive mechanism. It also is important to remember that the TAM cut both ways; if NTG rises, Enbridge receives a windfall when it can create higher savings with its available budgets.

While NTG and other evaluation changes are not entirely out of utility management control, in my experience, evaluation results often reflect random changes to evaluation methods and assumptions, or noise in evaluation data collection, rather than real changes in underlying market conditions or utility performance. I have seen many evaluations where NTG levels change, even though utility program designs do not change, and the evaluator offers no program design recommendations for improving NTG. Savings from low-volume, high savings programs like the Industrial and Large Volume programs are especially susceptible to NTG and other evaluation changes.

Likewise, Optimal's recommendation would make Enbridge shoulder inflation risks, which are entirely out of its control. This is especially important, as the Canadian and world economies experience high inflation from the COVID-19 pandemic and related supply chain disruptions.

Many other jurisdictions apply policies similar to the TAM to dampen effects of evaluation changes on utility performance metrics. Some jurisdictions go farther than Ontario's TAM process, and completely insulate utilities. These policies include approaches like:

- Prospective application of changes to NTG and gross savings.
- Fixed evaluation assumptions that do not change between approved plans and evaluated performance.
- Technical reference manuals that codify the algorithms and assumptions that used to measure savings in plans and evaluations.
- Savings goals that adjust automatically for changes to key inputs that update within the plan cycle
- Use of gross savings goals and metrics.

Finally, Optimal also recommends that, if the OEB adopts its Net Benefits performance metric, that the OEB also adopt a process for adjusting net benefit calculations for changes in forecasts of avoided gas supply and GHG costs that occur between plan approval and annual performance incentive calculations. This would require the OEB to create a TAM-like process for these adjustments. I don't understand how Optimal can recommend that the OEB eliminate the TAM for evaluation and inflation (and productivity) adjustments, but then institute a new TAM process to create new adjustments for avoided costs.

Ontario's TAM process has been in place for many years and, although I'm sure its processes could be improved, it has a successful track record. I support continuing the TAM as defined in Enbridge's proposed DSM Plan.

3.4.5.2. Mid-Point Assessment

Optimal recommends implementing a process for updates or modifications, similar to Enbridge's proposed Mid-Point Assessment process. In its recommendation to eliminate the TAM, Optimal also recommends allowing Enbridge to use the Mid-Point Assessment to update savings targets to incorporate evaluation changes.

Compared to the TAM process, Optimal's proposal severely limits Enbridge's ability to update target to reflect changing market conditions. Optimal's proposal:

- Only allows a one-time adjustment in in year 2, while the TAM adjusts goals every year
- Only adjusts for evaluation changes, while the TAM also addresses inflation and Enbridge's productivity in delivering savings within budget.
- Provides Enbridge no certainty that its proposed changes would be accepted by other parties or, ultimately, the OEB; in contrast the TAM applies consistent update rules that have been approved by the OEB and agreed to by all parties.

I support the Mid-Point Assessment process and agree with Optimal that it should continue. I disagree with eliminating the TAM process, and so do not support shifting evaluation updates from the TAM.

3.4.5.3. Budget and Performance Flexibility

Optimal recommends creating multi-year flexibility by "moving to a true multi-year approach, where budgets and targets are cumulative for the full 5-year plan period". The 5-year goals would still need to be translated into the annual goals required for the annual performance incentive process.

I support this idea, which is used in other jurisdictions like Illinois, where natural gas utilities manage 4-year budgets and 4-year goals. Utilities can make up for underperformance in one year, by carrying over unused budgets into the following year.

This approach is similar, but slightly different than Enbridge's DSMVA policy allowing Enbridge to increase budgets up to 15% if it projects savings will exceed 100% of targets. This provides Enbridge the flexibility to continue program operations in successful year when budgets track to be fully spent by year end. Without the 15% cushion, Enbridge might be forced to shut down program operations or put customers on waiting lists, which would be disruptive to customers and trade allies.

This DSMVA policy also provides some protection to Enbridge to recover from down years. For example, if Enbridge has a bad year—for example, due to slow startup of a new program or to a large industrial project falling through— but then recovers in the following year, Enbridge can use the 15% provision to make up for some of savings (and budget) it lost the previous year. But the 15% cap limits Enbridge's flexibility; for example, if the budget shortfall one year is more than 15%, Enbridge cannot fully make up the difference.

I recommend that the OEB accept Optimal's recommendation and allow Enbridge to manage 5-year budgets, while also continuing the 15% policy. This would provide the best of both worlds and maximize Enbridge's flexibility to manage budgets and maximize benefits across the 5-year plan horizon.

Regarding 5-year performance targets, since Optimal recommends any 5-year goals be translated into annual targets, I don't think this recommendation has much bearing on the current proceeding.

Finally, Optimal also recommends allowing additional flexibility by possible measuring annual savings with "estimated and reported (and potentially unverified or evaluated) performance" and by reducing requirements for savings verifications "for well-established programs, particularly where the verification process does not entail significant site visits". I think this can streamline the evaluation process and support this approach.

3.5. Summary of Compromise Proposal and Recommendations on Performance Incentives

Table 10 repeats Table 9 presented at the beginning of Section 3.4 outlining my compromise proposal. This section summarizes my recommendations incorporated into my compromise proposal.

Table 10: Compromise Performance Incentive Proposal

Component	Metric	Sub-Target	Frequency	5-Year Incentive Payment ($M)		Threshold (% of Proposed Plan)	
				Max	Share	Min	Max
Annual Scorecards: RA*	Net Annual Savings	7 Sub-Targets	Annual	$ 102.3	93%	50%	150%
Annual Scorecards: MY#	Participants	8 Sub-Targets	Annual	$ 6.2	6%	50%	150%
Low Carbon Transition+	MT Metrics	4 Sub-Targets	Year 2, 5	$ 2.0	2%	50%	150%
Net Benefits	------	*Eliminate*	------				
GHG Reduction	------	*Eliminate*	------				
Total				**$ 110.5**	**100%**		
Total as % of Budget				**15.5%**			

*RA=Resource Acquisition
#MY=Multi Year

Changes Recommended to Performance Incentive Management Process:
- Maintain TAM.
- Maintain Mid-Point Assessment.
- Maintain ring-fenced budgets.
- Manage 5-year budgets.
- Maintain DSMVA 15% budget increases..
- Increase maximum incentive pool if savings targets increase.
-Simplify evaluation measurements and verification requirements.

3.5.1. Recommendations Incorporated into the Compromise Proposal

3.5.1.1. Performance Incentive Components

- Maintain annual scorecard for Resource Acquisition and Multi Year programs, as proposed by Enbridge.
- Eliminate Annual Net Benefits component, as recommended by EFG.
- Maintain long term scorecard component for Low Carbon Transition program, as proposed by Enbridge.
- Eliminate Long-Term GHG Reduction component, as recommended by Optimal and EFG.
- Include multiple countervailing metrics and features, as recommended by Optimal.

3.5.1.2. Maximum Performance Incentive Payments

- Increase performance incentive pool if budgets or savings goals increase substantially, as recommended by Optimal and EFG.

3.5.1.3. Performance Metrics

- Maintain net annual savings metrics for Resource Acquisition scorecards, as proposed by Enbridge.
- Maintain participation metrics for Multi Year programs, as proposed by Enbridge.

3.5.1.4. Performance Targets

- Maintain targets proposed by Enbridge, although I understand that the OEB is considering evidence from multiple parties recommending changes to those targets.

3.5.1.5. Performance Thresholds

- Maintain 50% floors and 150% ceilings for scorecard metrics, as proposed by Enbridge.

3.5.1.6. Performance Incentive Management Process

- Maintain TAM, as proposed by Enbridge.
- Maintain Mid-Point Assessment, as proposed by Enbridge.
- Maintain ring fenced budgets, as proposed by Enbridge.
- Allow Enbridge to manage 5-year budget, as proposed by Optimal.
- Maintain DSMVA policy to increase rate class budgets by up to 15%, as proposed by Enbridge.
- Simplify evaluation measurements and verification requirements, as proposed by Optimal.

3.5.2. Recommendations Excluded from the Compromise Proposal

By maintaining components of the Enbridge proposal, I also recommend that the OEB reject certain recommendations made by Optimal and EFG, including:

3.5.2.1 Performance Incentive Components

- Reject Optimal recommendation to create a Net Benefits component tied to PAC-Plus net benefits metric
- Reject EFG recommendation to eliminate Annual Multi Year components for the Energy Performance and Beyond Building Code programs.
- Reject EFG recommendation to shift focus of Low Carbon Transition program away from gas heat pumps.
- Reject EFG recommendation to change the Long-Term scorecard allocation to a new Long-Term Energy Intensity objective.

3.5.2.2. Performance Metrics

- Reject EFG and Optimal recommendations to change Resource Acquisition scorecards metrics from net annual savings to net lifecycle savings.
- Reject Optimal recommendation to change metrics for Multi Year programs from participation to gas savings.

3.5.2.3. Performance Thresholds

- Reject EFG and Optimal recommendations to change scorecard performance thresholds to 75% floors and to ceilings of 110%-125% (Optimal) or 125% (EFG).

3.5.2.4. Performance Incentive Management Process

- Reject Optimal recommendation to eliminate TAM.
- Reject Optimal recommendation to incorporate evaluation changes in the Mid-Point Assessment.

4. SAVINGS BENCHMARKS FROM OTHER UTILITIES

4.1. Benchmarks from Other Jurisdictions

EFG presents benchmarks showing savings achieved by utilities in other jurisdictions, with annual savings varying from 1.05% to 1.33%, which EFG characterizes as being “about twice as much as Enbridge”.[66]

I caution the OEB in using these benchmarks to set performance targets for Enbridge, since these other jurisdictions have very different regulatory environments, market conditions, and resources available to them. For example:

- Xcel Energy, in Minnesota, tracks performance against gross savings, not net savings.
- Furnace equipment standards in Canada require minimum efficiencies of 95%, while standards in the United States remain at 78% (although manufacturers don’t produce units with efficiencies below 80%)
- National Grid, Eversource, and Consumers have behavior programs that provide large amounts of annual savings, but much smaller lifecycle savings.
- National Grid and Eversource are allowed to claim large savings from stretch building codes, while it is unclear that Enbridge would be allowed the same treatment as Ontario’s stretch building codes roll out.
- National Grid and Eversource have budgets that are at least twice those proposed by Enbridge, when adjusted for the size of the service territories.

[66] EFG Report, page 11.

FORM A

Proceeding EB-2021-0002

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is *Edward Weaver*. I live at *508 Hoover Street, Nelson*, in the *Canadian* province of *British Columbia*.

2. I have been engaged by or on behalf of *Enbridge Gas, Inc.* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date .January 19, 2022

Edward M Weaver
Signature

EDWARD M. WEAVER

First Tracks Consulting Service, Inc. **Nederland, CO**
President ***2000 - present***
Founder of management consulting company serving clients in the utility, energy service, and energy technology industries. Specializing in strategic consulting services, including long-term planning, business-cycle planning, procurement, organizational development, regulatory support, and stakeholder engagement. Developed dozens of business plans, integrated resource plans, and energy efficiency plans, covering hundreds of energy efficiency programs and new energy technologies. Helped clients develop and operate over $6 billion in energy efficiency services and over 2 GW of electric generation. Testified in 16 state utility commission proceedings. Participated in and facilitated dozens of stakeholder groups. Completed projects in over 40 North American states and provinces. Performed techno-economic analysis in emerging technology markets.

LongPath Technologies **Boulder, CO**
Chief Executive Officer ***2017 - 2018***
Partner ***2017-present***
Co-founder of technology startup providing laser-based air quality services to the oil and gas industry. Company leverages Nobel-Prize winning laser technology developed at the University of Colorado and the National Institute of Standards and Technology to manufacture and deploy autonomous, wide-area methane monitoring networks using a service company business model. Responsible for strategic direction, licensing agreements, investor relations, business development, and strategic partnerships.

Rolling Energy Resources **Boulder, CO**
Partner ***2021-present***
Minority partner in technology startup providing smart EV charging services.

PG&E Energy Services, Inc. **San Francisco, CA/Boulder, CO**
Director, Strategy & Planning (and other titles) ***1997 - 2000***
Reported directly to the CEO of retail service company selling electricity, natural gas, and other energy services to customers throughout the United States. Responsible for business planning, commodity market strategy, strategic alliances, and risk management.

Barakat & Chamberlin, Inc. **Oakland, CA/Boulder, CO**
Principal/Partner (and other titles) ***1988 - 1997***
Partner Managed multimillion dollar practice within international management consulting firm. Specialized in business planning, new business creation, integrated resource planning, and power supply procurement.

Burlington Electric Department **Burlington, VT**
Demand-Side Planner ***1987 - 1988***
Developed first integrated resource plan for municipal electric utility. Managed rate department.

Vermont Department of Public Service **Montpelier, VT**
Electricity Planner ***1985 - 1987***
Responsible for statewide energy planning. Primary author of 1997 State Electricity Plan.

Energy Systems Research Group (Now Tellus Institute) **Boston, MA**
Research Assistant ***1979 - 1985***
Contributed to projects involving energy efficiency, resource planning, and litigation support.

EDUCATIONAL RECORD

Massachusetts Institute of Technology, Bachelor of Science, 1984
Graduate courses in economics and statistics, University of Vermont, 1986-87

SELECTED CLIENTS

Alberta Power
Ameren Illinois
Ameren Missouri
American Electric Power
Arkansas Public Service Commission
Arizona Public Service
Atmos Energy
BC Hydro
Boulder County (CO)
Burlington Electric Department
Canadian Electrical Association
Cinergy
Chevron Energy Solutions
City Public Service (San Antonio, TX)
City Utilities (Springfield, MO)
City of Boulder, CO
Colorado Governor's Energy Office
Colorado Natural Gas
Colorado Public Utilities Commission
Colorado Springs Utilities
Commonwealth Edison
Consumers Energy
Delmarva Power
Detroit Edison
Electric Power Research Institute
Enbridge
Energy Conversion Devices
E Source
Eversource
Georgia Power
Hawaii Department of Business, Economic Development & Tourism
Iowa Power
Iowa Utilities Association
IPS Electric
Lower Colorado River Authority
Los Angeles Department of Water & Power
Midwest Gas
Midwest Power
MidAmerican Energy
National Grid
National Institutes of Standards and Technology
Nature Conservancy
Newfoundland & Labrador Hydro
New York Power Authority
Nicor Gas
North Shore Gas
Oklahoma Gas & Electric
Pacific Gas & Electric
Pennsylvania Public Utilities Commission
Peoples Gas
PSI/Energy
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Company of Oklahoma
PSEG
Salt River Project
SourceGas
Southwestern Electric Power Company
Southwestern Public Service
Southern California Edison
Southern California Gas
Texaco Ovonic Battery Systems
Texaco Ovonic Hydrogen Systems
Trane
University of Colorado
Vectren Retail

TESTIMONY AND SUBMITTALS BEFORE STATE PUBLIC UTILITIES COMMISSIONS

2018: Illinois Commerce Commission, Docket 18-1688
2018: Illinois Commerce Commission, Docket 18-1135
2013: Illinois Commerce Commission, Docket 13-0549
2010: Illinois Commerce Commission, Docket 10-0568
2008: Iowa Utilities Board, Docket EEP-08-2
2007: Illinois Commerce Commission, Docket 08-0108
2003: Iowa Utilities Board, Docket EEP-03-1
1996: Iowa Utilities Board, Docket EEP-95-3
1994: Iowa Utilities Board, Docket ECR-94-1
1994: Hawaii Public Utilities Commission, Docket 94-0206
1994: Iowa Utilities Board, Docket ECR-93-2
1993: Hawaii Public Utilities Commission, Docket 7257
1993: Colorado Public Utilities Commission, Docket 91A-481EG
1992: Iowa Utilities Board, Dockets EEP-91-8/92-1
1991: Iowa Utilities Board, Docket EEP-91-3
1988: Vermont Public Service Board, Docket 5270
1987: Vermont Public Service Board, Docket 5177