Request IR-01:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Pdf pg. 9 outlines that the Preferred Plan will save 14 GWh of energy through low income and equity programs; 85 MW a cumulative peak demand; 29.3 MW of capacity through demand response; and 1.7 GWh through customers' solar installations.

(a) Please explain how E1 determined these estimated savings for the three categories.

i) Please outline what was involved in selecting these areas of E1's programming and services.

Response IR-01:

(a) Please refer to EfficiencyOne's response to NSEB IR-33.

i) Please refer to part (a) of this IR response.

Request IR-02:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Approval of Purchase Agreement with NS Power: Pdf pg. 9 of the Application states: "E1 also requests the NSEB's approval of its Purchase Agreement with NS Power, together with the associated Performance Targets, which is attached in redline form as Appendix "D" and in clean form as Appendix "E" (clean)."

(a) Please confirm that NS Power is in agreement with the proposed changes noted in Appendix D.

(b) With regard to Appendix D of the Application:

i) In Schedule A (pdf pg. 360 of the Application), please explain why "Annual" performance targets have been removed from the agreement in favour of "Total Net" over the term of the proposed DSM plan.

Response IR-02:

(a) EfficiencyOne (E1) did provide a redline and clean version of the proposed Purchase Agreement to NS Power prior to filing the 2027–2031 DSM Plan. E1 did not receive any specific response related to the Purchase Agreement from NS Power prior to filing.

(b)

i) The references of "cumulative" and "annual" caused confusion. Schedule A's language referencing the performance targets is now consistent with the terms in the Standardized Filing Framework.

Request IR-03:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Pdf pg. 16 of the Application states: "Given the affordability concerns raised by DSM Advisory Group (DSMAG) members, as discussed in Sections 3.1.1 and 4.1, the Preferred Plan constrains investment to 2026 levels with no annual inflationary increases to the investment, while maintaining a portfolio that delivers long term benefits to ratepayers, consistent with the NSEB's direction to consider both affordability and long-term cost reduction. This approach satisfies the NSEB's interpretation of "cost-effective" DSM as that which is "affordable" and results in the "lowest long-term cost of electricity," while also responding to the *ERBA* section 6(2) requirement to ensure the provision of economical energy supply."

(a) Please explain specifically why E1 believes that its proposed annual $63.75M investment is "affordable" for ratepayers.

(b) For the average NS Power residential customer, what percentage of the customer's annual 2026 NS Power bill (exclusive of any other riders) and what dollar amount does the annual DSM Rider represent (if E1 does not know the annual electricity use of NS Power's average customer, please provide this analysis for two separate customers: a) one who uses 6,000 kW/hr of electricity per year, and b) one who uses 12,000 kW/hr of electricity per year).

Response IR-03:

(a) Affordability was the primary consideration in the design of the 2027–2031 DSM Plan consistent with past Nova Scotia Utility and Review Board now the Nova Scotia Energy

Board (NSEB) decisions and the *Public Utilities Act*. The NSEB confirmed in its 2025 Benefit Cost Analysis (BCA) Test Decision that "the purpose of the demand-side management provisions in the *Public Utilities Act* is to reduce electricity costs for customers." [1]

EfficiencyOne (E1) has relied on NSEB past decisions and provincial legislation to determine that the 2027–2031 DSM Plan investment of $63.75 million per year is considered affordable. The NSEB's approval of the 2023–2025 DSM Plan confirmed that the 2025 investment of $62.5 million was affordable which was further confirmed through legislation. On March 26, 2025, the Nova Scotia government passed legislation to extend E1's current approved 2023–2025 DSM Plan by an additional year with a prescribed investment level of $63.75 million for the 2026 one-year extension. The investment of $63.75 million for the 2026 DSM Extension represented a modest increase of 2 percent for inflation from the 2025 approved investment.

E1 understands that affordability balances both short term and long-term considerations. In the current economic environment, E1 has prioritized near-term affordability while maintaining long-term value in recognition of the unique current economic circumstances. Nova Scotians face significant cost-of-living pressures, rising unemployment, rising interest rates, electricity rate increases and other adverse effects from the expansion of U.S. tariffs on Canada and most recently increases in oil prices resulting from the war in Iran. E1 does not consider this situation to be reflective of past challenges faced by Nova Scotians and cannot speculate on how long the lingering effects will continue. E1 has constrained the annual DSM investment to the 2026 approved level of $63.75 million, with no annual inflationary increases to the investment, for each year of the 2027–2031 Plan period, resulting in a total investment of $318.75 million. Given these affordability pressures, E1

[1] M12282, NSEB Decision, E1 New Benefit Cost Analysis Test for Evaluating Demand Side Management (DSM) Plans, December 10, 2025, page 53, para 128.

concluded that maintaining current investment levels - rather than seeking growth - was the appropriate and responsible approach at this time.

E1's proposed 2027–2031 DSM Plan has also considered long term affordability which is demonstrated by:

- Continuing to prioritize customers by ensuring that the investment in customer incentives remains not only the largest portion of $63.75 million per year but increases as a percentage of total investment as compared to the 2026 DSM Extension. In the Preferred Plan customer incentives account for 71 percent of total costs—an increase from 66 percent in the 2026 DSM Extension.
- Including measures within the DSM Extension providing benefits that will accrue to customers for an average of 12.3 years for energy efficiency and 30.0 years for solar PV.
- Demonstrating that DSM is a long-term investment with lasting benefits and considerable lifetime savings, by saving Nova Scotians $682.5 million in avoided utility costs.
- Providing a payback period of five years where the DSM Plan investment is fully recovered through the benefits.
- Capping the spending for the duration of each term at the level of investment previously approved by the Energy Board.

E1 acknowledges that this approach results in lower long-term energy savings to ratepayers than would be achieved by a plan more fully aligned with the scale of DSM savings contemplated by the Integrated Resource Plan (IRP). However, this reflects a deliberate and considered judgment by E1 that, given the significant economic pressures currently facing Nova Scotians - including cost-of-living increases, rising unemployment, escalating electricity rates, and the effects of U.S. tariffs - prioritizing near-term

affordability is the appropriate course at this time. E1 wishes to be clear that this constrained investment level is a response to specific and extraordinary economic circumstances prevailing at the time of filing, and should not be interpreted as E1's view of the appropriate long-term level of DSM investment. E1's long-term position, consistent with the IRP, remains that Base-level DSM - targeting approximately 1.2 percent of load in energy savings - is in the best long-term interests of ratepayers, as it delivers the lowest revenue requirement over time. E1 is committed to pursuing DSM investment at levels consistent with the IRP as economic and regulatory conditions allow and intends to assess the appropriate level of investment for future plan periods on its own merits, having regard to the prevailing circumstances at that time.

(b) E1 does not have the average residential customer's NS Power bill information. However, E1 is providing information related to the Program Cost Recovery Rider (PCR) only, part of NS Power's DSM Cost Recovery Rider (DCRR), which is directly related to E1's DSM costs in a DSM Plan. E1 is providing an estimate only of what the PCR could be for the 2027–2031 DSM Plan. As this is an estimate only at this time, it is subject to change when NS Power files the DCRR application for any of the given years in the DSM Plan. Please see the tables below.

Impact of 2027-2031 DSM Plan on Residential Customers Bills			
Customer Uses 6,000 kWh per year			
	Estimated PCR per year	Annual Estimated PCR	
Year	Cents / kWh	Total Dollars	Total Annual Increase / (Decrease)
2026	0.642	$ 38.52	
2027	0.583	$ 35.01	(3.51)
2028	0.642	$ 38.53	3.52
2029	0.728	$ 43.67	5.14
2030	0.745	$ 44.72	1.06
2031	0.756	$ 45.38	0.66
Customer Uses 12,000 kWh per year			
	Estimated PCR per year	Annual Estimated PCR	
Year	Cents / kWh	Total Dollars	Total Annual Increase / (Decrease)
2026	0.642	$ 77.04	
2027	0.583	$ 70.01	(7.03)
2028	0.642	$ 77.06	7.05
2029	0.728	$ 87.34	10.28
2030	0.745	$ 89.45	2.11
2031	0.756	$ 90.77	1.32

Request IR-04:

<u>Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)</u>

With regards to Section 2.2.1.1 "Compliance with the 2023-2025 DSM Plan Decision":

(a) Reference Exhibit E-1, page 14 of 71 (pdf pg. 21), E1 notes that for the 2027-2031 DSM Plan, avoided costs for capacity have generally increased and avoided cost for energy have generally decreased in the early years of analysis.

i) Please explain the reasons for these trends.

(b) Pdf pg. 21 states: "… E1 incorporated updated avoided costs from NS Power, from the 2022 Evergreen IRP in the 2026 DSM Extension and subsequently for the 2027–2031 DSM Plan as well. Specifically, E1 has used the avoided costs provided by NS Power from the 2022 Evergreen IRP process (provided to the DSMAG on January 8, 2026)."

i) In line with the new legislative requirement to develop a five-year plan, does E1 consider the emissions impacts calculated using NS Power's 2022 IRP remain accurate over the plan term?

ii) Does E1 have any plan or mechanism to adjust the calculation when IESO-NS provides an updated IRP?

- **Are there any evaluation or review processes in place for these types of changes?**
- **Is there a process to incorporate updated values into the Preferred Plan?**

(c) Pdf pg. 22 states: "In response to the directive to provide justification for individual measures that fail cost effectiveness testing, E1 notes that only nine of the 341 measures included in the Preferred Plan do not, on an individual basis pass the cost-effectiveness

test in any year of the 2027–2031 DSM Plan. E1 has provided specific justification for each measure that fails cost-effectiveness testing, as set out in Appendix A, Attachment 3."

i) Regarding Appendix A, Attachment 3:

- **For the "HW – Heat Pump Cleanings" measure under the "Affordable Single-Family Homes" program:**
  - **a) Please explain why the "Measure Life" is only 2 years.**
  - **b) Please provide background information to support the $600 incentive per unit in 2027. Please ensure that this information includes actual typical costs for heat pump cleaning in Nova Scotia for 2025 and 2026, broken down by single unit cleaning, two-head cleaning, three-head cleaning, and four-head cleaning.**
    - **A. Please confirm how the $600 incentive per unit is determined (i.e., is it for $600/per mini split head?)**
  - **c) What is the average number of mini-split heads cleaned per customer that has been assumed under this measure?**
  - **d) Please identify the PAC score for each of 2027 to 2031 if the 2027 incentive was $200/unit instead of $600/unit.**

- **For the "MHEEP – Heat Pump Cleanings" measure under the "Affordable Single-Family Homes" program:**
  - **a) Please explain why the "Measure Life" is only 2 years.**
  - **b) Please provide background information to support the $600 incentive per unit in 2027. Please ensure that this information includes actual typical costs for heat pump cleaning in Nova Scotia for 2025 and 2026, broken down by single unit cleaning, two-head cleaning, three-head cleaning, and four-head cleaning.**

A. Please confirm how the $600 incentive per unit is determined(i.e., is it for $600/per mini split head?)

c) What is the average number of mini-split heads cleaned per customer that has been assumed under this measure?

d) Please identify the PAC score for each of 2027 to 2031 if the 2027 incentive was $200/unit instead of $600/unit.

- **For the "IR – Griddle – Electric" measure under the "Business Energy Rebates" program:**

a) Please explain what E1 means in the "PAC Review" tab by: "In fact, application rebates variation is on the cusp of passing PAC in 2027 and 2028, and passes from 2029-2031." In providing this response, please clarify what is meant by "the application rebates variation" and explain why this is relevant.

b) Please provide background information to support the $1,500 incentive per unit in 2027. Please ensure that this information includes actual typical costs for commercial kitchen electric griddles for 2025 and 2026.

c) Please identify the PAC score for each of 2027 to 2031 if the 2027 incentive was $1,000/unit instead of $1,500/unit.

- **For the "Solar Security Fixture" measure under the "Efficient Products Installation" program:**

a) In the "PAC Review" tab, in stating: "This is a complimentary measure in Efficient Product Installation that allows installers to do more during home appointments, which are offered to customers at no-cost.", please describe the additional items that installers would complete during a related home appointment under this measure.

A. Please explain how a customer would confirm that it qualified for the incentive under this measure.

b) Please explain why the "Measure Life" is only 2.5 years.

c) Please provide background information to support the $184.83 incentive per unit in 2027.

d) Please identify the PAC score for each of 2027 to 2031 if the 2027 incentive was $20/unit instead of $184.83/unit.

- **For the "Outdoor Motion Sensor" measure under the "Efficient Products Installation" program:**

a) In the "PAC Review" tab, in stating: "This is a complimentary measure in Efficient Product Installation that allows installers to do more during home appointments, which are offered to customers at no-cost.", please describe the additional items that installers would complete during a related home appointment under this measure.

A. Please explain how a customer would confirm that it qualified for the incentive under this measure.

b) Please provide background information to support the $92.41 incentive per unit in 2027.

c) Please identify the PAC score for each of 2027 to 2031 if the 2027 incentive was $15/unit instead of $92.41/unit.

- **For the "Indoor Motion Sensor" measure under the "Efficient Products Installation" program:**

a) In the "PAC Review" tab, in stating: "This is a complimentary measure in Efficient Product Installation that allows installers to do more during home appointments, which are offered to customers at no-cost.", please describe the additional items that installers would complete during a related home appointment under this measure.

A. Please explain how a customer would confirm that it qualified for the incentive under this measure.

b) Please provide background information to support the $59.36 incentive per unit in 2027.

c) Please identify the PAC score for each of 2027 to 2031 if the 2027 incentive was $5/unit instead of $59.36/unit.

- **For the "Energy Star Certified Combination Washer/Dryer Units" measure under the "Instant Savings" program:**

a) Please explain how a customer would confirm that it qualified for the incentive under this measure.

b) Please provide background information to support the $129 incentive per unit in 2027.

c) Please identify the PAC score for each of 2027 to 2031 if the 2027 incentive was $100/unit instead of $129/unit.

(d) Pdf pg. 22 states: "In response to the directive to provide payback information for measures with a payback period of three years or less, E1 has provided the incentive level analysis for measures in Appendix A, Attachment 3."

i) Regarding Appendix A Attachment 3:

- **For the "Energy Star certified Room Air Purifiers (RAP)" measure under the "Instant Savings" program, it appears that E1 has budgeted between $240,800 to $309,600 for each year for the 2027-2031 DSM plan. The payback period for this measure without incentives is 1.24 years. The justification for the measure is: "This is a measure that many retailers can offer so it helps us provide a more robust offering. This measure also has added health benefits, as it helps improve indoor air quality."**

a) **Please provide more detailed justification for this measure given its payback period without incentives is relatively short at just over one year.**

b) Please identify the estimated annual improvement in air quality as a result of implementing this measure, and explain how this would be measured.

A. Please explain how this aligns with the legislative framework which the Board must consider when evaluating the proposed DSM plan.

- **For the "Custom - Strategic Energy Management" measure under the "SEM" program, it appears that E1 has budgeted between $180,000 to $240,000 for each year for the 2027-2031 DSM plan. The payback period for this measure without incentives is 1.04 years. The justification for the measure is: "This is a program component aimed at establishing a structured, continuous approach to helping customers improve energy performance, reduce costs, and achieve long-term operational efficiency. It is intended to have a very short payback to keep customers engaged and focused on longer term savings. Its inclusion in the Plan is consistent with prior Board approvals."**

a) Please provide more detailed justification for this measure given its payback period without incentives is relatively short at just over one year.

b) Please explain specifically how this measure helps establish a structured, continuous approach to helping customers improve energy performance, reduce costs, and achieve long-term operational efficiency.

c) Board staff notes that Table 37 of Appendix A of Exhibit E-1 (pdf pg. 158), shows proposed annual investment for the Strategic Energy

Management Program Component ranging from $1.0M to $1.1M from 2027 to 2031, for a total investment of $5.4M over this period. However, Appendix A, Attachment 3 shows "Custom - Strategic Energy Management" as the only measure under this program with annual PAC costs ranging from $180,000 to $240,000 for each year for the 2027-2031 DSM plan. Please explain and reconcile Table 37 with Appendix A, Attachment 3.

A. If required, please recalculate the Attachment 3 annual PAC score and payback period for this measure for each year from 2027 to 2031, and provide a revised Appendix A Attachment 3 in Excel format with all formulae intact and unaltered.

Response IR-04:

(a) The following IR response for part (a) (i) has been provided by NS Power.

i) Avoided Energy Costs have decreased in the early years because the Base Case (with DSM) had higher carbon emissions than the No DSM Case, increasing the total cost of carbon in the Base Case, and reducing the overall Avoided Cost of DSM. This was a result of higher coal and gas generation in the Base Case for those years. The No DSM Case builds more wind than the Base Case in 2027 (200 MW more) and 2029 (100 MW more) to meet the renewable generation targets at higher loads than the Base Case. It is important to note that annual costs can fluctuate significantly depending on the timing of new capacity builds. The best approach is to normalize these costs over time. Therefore, it is recommended to use the Equivalent Escalating Series rather than the Annual Avoided Energy Costs. When using the Equivalent Escalating

Series, the Avoided Cost of Energy has increased between updates for the years 2027-2031.

Capacity Costs have increased over the entire time horizon due to an increase in market costs, between updates, for new resources selected by the model for capacity (i.e. combustion turbines and battery energy storage systems).

(b)

i) EfficiencyOne (E1) relies on the Integrated Resource Plan (IRP) process to provide information on future system expectations, including emissions impacts. The emissions impacts from NS Power's 2022 IRP are the most current emissions forecast data available to E1. E1 has not independently assessed whether the emissions forecasts contained in the 2022 Evergreen IRP will remain accurate over the 2027–2031 plan term. E1 does not have insight into whether any emissions forecast that may be developed through the Nova Scotian Independent Energy System Operator (NSIESO) 2026 IRP process will deviate from those set out in the 2022 Evergreen IRP. In the event that updated emissions data becomes available through a future IRP process, E1 would expect to incorporate that data into subsequent DSM planning cycles.

ii) E1 engages an independent evaluation consultant to conduct an evaluation of its DSM programs annually. Greenhouse gas emissions are assessed as part of the annual impact evaluations and are reported in the DSM Evaluation Reports which are filed each year on March 31 with the Nova Scotia Energy Board (NSEB). The evaluation uses the most recently available total system emissions data and total electricity generations data as reported by NS Power to establish a Nova Scotia specific emissions factor. In this way updated annual emissions data will be reflected in the

annual DSM evaluation reports. Please also refer to E1's response to NSEB IR-63 part (a), and Synapse IR-13.

- Please refer to part (b) (ii) of this IR response.
- Please refer to part (b) (ii) of this IR response.

(c)

i)

- For the "HW – Heat Pump Cleanings" measure under the "Affordable Single-Family Homes" program:
  a) The heat pump cleaning measure characterization details were largely obtained from the Wisconsin Focus on Energy 2024 Technical Reference Manual. The assumption is that a heat pump requires cleaning and maintenance roughly every two years to ensure the system is performing as expected. Please refer to NS Power IR-14 for additional details on the Technical Reference Manual used.
  b) In 2025, E1 issued a Request for Standing Offer procurement for heat pump installation and maintenance services under the Affordable Single-family Homes program component. Contractors who responded provided heat pump cleaning costs based on a wide range of system configurations seen under the program component (see below). The average cost spanned roughly $280-$650 per visit, depending on the number of indoor and outdoor units. E1 considered it diligent to assume an average cost on the higher end of this spectrum given the heat pump systems installed through the program component.

Heat pump configuration		Average price per visit
Number of outdoor units	Number of indoor units	
1	1	$277.97
1	2	$372.71
1	3	$472.73
1	4	$562.14
1	5	$650.44

c) E1 has assumed an average of two outdoor units and two indoor units are cleaned per customer.

d) Table 1, below, provides an estimate of the heat pump cleaning measure PAC results if a $200 incentive is used. These results were not generated by the Guidehouse Process model; rather, they were produced through a manual calculation performed by E1 outside the model, using the same underlying participation data as the DSM Plan, but substituting the incentive amount as provided in this IR in place of the incentive used in the DSM Plan. While this approach provides a reasonable estimate, it should be understood as an approximation.

Table 1: Estimated PAC Results for Heat Pump Cleaning Measure

	2027	2028	2029	2030	2031
HW - Heat Pump Cleaning with $200/incentive	0.75	0.71	0.86	0.83	0.84
MHEEP - Heat Pump Cleaning with $200/incentive	0.75	0.71	0.86	0.83	0.84

- For the "MHEEP – Heat Pump Cleanings" measure under the "Affordable Single-Family Homes" program:
  a) Please refer to response (c) i) a) for HW – Heat Pump Cleanings.
  b) Please refer to response (c) i) b) for HW – Heat Pump Cleanings.
  c) Please refer to response (c) i) c) for HW – Heat Pump Cleanings.
  d) Please refer to response (c) i) d) for HW – Heat Pump Cleanings.

- For the "IR – Griddle – Electric" measure under the "Business Energy Rebates" program:
  a) The Business Energy Rebates program component has two customer pathways. There are instant rebates available to customers through

participating distributors. Customers can also submit a rebate application to E1 for approval. The comment referenced was simply noting that this electric griddle measure has potential within the program component since it passes PAC under the alternate program delivery stream, which has lower delivery costs because no third parties are involved.

b) Apex Consulting assisted E1 in developing the full retrofit and incremental costs for measures where there has been limited historical participation in E1's programs. The full retrofit and incremental costs for electric griddles are estimated at roughly $13,000 and $3,200, respectively. E1's proposed incentive is $500 per linear foot of griddle width to accommodate various sized units. The $1,500 incentive assumes an average griddle size of three linear feet.

c) Table 2, below, provides an estimate of the IR – Griddle – Electric measure PAC results if a $1,000/unit incentive is used. These results were not generated by the Guidehouse Process model; rather, they were produced through a manual calculation performed by E1 outside the model, using the same underlying participation data as the DSM Plan, but substituting the incentive amount as provided in this IR in place of the incentive used in the DSM Plan. While this approach provides a reasonable estimate, it should be understood as an approximation.

Table 2: Estimated PAC Results for IR-Griddle-Electric Measure

	2027	2028	2029	2030	2031
IR – Griddle – Electric $1,000/incentive	0.8	0.89	0.96	1.01	1.02

- For the "Solar Security Fixture" measure under the "Efficient Products Installation" program:

a) Efficient Product Installation appointments are focused on installing smart thermostats, draft proofing measures, and water conservation measures, as these are the lower unit cost offerings. Solar security fixtures, outdoor motion sensors, and indoor motion sensors are the higher unit cost measures that E1 considers complementary, meaning these would typically only be installed alongside the other measures mentioned above.

   E1 Service Providers are given program guidelines to screen potential participants when booking appointments. This gives them a sense of what products could be installed and if a home visit is likely to yield sufficient energy savings. Ultimately, the Service Providers would use their best judgement to determine what mix of products should be installed. At the end of each month, E1 reviews what each participant received to ensure the guidelines are being followed and gives Service Providers more direction as needed.

b) The measure life is determined by E1's independent third-party Evaluator, which conducts a literature review to determine this parameter.

c) E1 conducted a public procurement to hire Service Providers for the Efficient Product Installation program component. The incentive costs reflect the average cost that Service Providers bid on this product (material and labour).

d) E1 notes that direct install costs for this program are not variable in the same way as in other programs. Measure costs include average material and labour costs as negotiated with Service Providers and reducing the cost for one measure as proposed in this IR would have a

ripple effect on the other measures that is not reflective of program delivery.

Most appointments focus on a core set of lower-cost measures, such as smart thermostats, draft proofing, and water conservation devices. Higher-cost items are only installed as add-ons and typically alongside these core measures, which limits overall cost variation.

Service Providers follow program guidelines when selecting measures, and EfficiencyOne reviews installations monthly to ensure consistency. Together, this structured approach keeps costs stable and predictable, rather than highly variable.

- For the "Outdoor Motion Sensor" measure under the "Efficient Products Installation" program:
    a) Please refer to response (c) i) a) for Solar Security Fixture.
    b) Please refer to response (c) i) c) for Solar Security Fixture.
    c) Please refer to response (a) i) d) for Solar Security Fixture.

- For the "Indoor Motion Sensor" measure under the "Efficient Products Installation" program:
    a) Please refer to response (c) i) a) for Solar Security Fixture.
    b) Please refer to response (c) i) c) for Solar Security Fixture.
    c) Please refer to response (a) i) d) for Solar Security Fixture.

- For the "Energy Star Certified Combination Washer/Dryer Units" measure under the "Instant Savings" program:

a) Any Nova Scotian can visit a participating retailer to purchase an eligible product. The retailer provides the incentive at the point of sale.

b) E1 collects product cost data from participating retailers. The full retrofit and incremental costs for Energy Star Certified Combination Washer/Dryer Units are estimated at roughly $3,300 and $500, respectively. E1's proposed $129 incentive represents a small portion of the total product costs.

c) Table 3, below, provides an estimate of the Energy Star Certified Combination Washer/Dryer Units measure PAC results if a $100/unit incentive is used. These results were not generated by the Guidehouse Process model; rather, they were produced through a manual calculation performed by E1 outside the model, using the same underlying participation data as the DSM Plan, but substituting the incentive amount as provided in this IR in place of the incentive used in the DSM Plan. While this approach provides a reasonable estimate, it should be understood as an approximation.

Table 3: Estimated PAC Results for Energy Star Certified Combination Washer/Dryer

	2027	2028	2029	2030	2031
Energy Star Certified Combination Washer/Dryer $100/incentive	0.98	1.09	1.18	1.24	1.26

(d)

i)

- For the "Energy Star certified Room Air Purifiers (RAP)" measure under the "Instant Savings" program, investment ranges between $240,800 to $309,600 for each year for the 2027–2031 DSM plan. The payback period for this measure without incentives is 1.24 years. The justification for the measure is

that this is a measure that many retailers can offer so it helps us provide a more robust offering. This measure also has added health benefits, as it helps improve indoor air quality.

a) E1 has identified Energy Star certified Room Air Purifiers as a product with growth potential. Although energy savings are strong for this measure and the payback is estimated to be short, only about 6,000 units were incentivized through the Instant Savings program component in 2024 and 2025 combined. E1 believes there is a need to continue incentivizing and promoting this product to increase adoption and achieve that potential.

b) E1 does not currently measure, nor has it estimated, the annual improvement in air quality as a result of supporting this product. The benefit cost analysis test approved by the Nova Scotia Energy Board, being the PAC, does not take into account such benefits.

- For the "Custom - Strategic Energy Management" measure under the "SEM" program component, investment ranges between $180,000 to $240,000 for each year for the 2027–2031 DSM plan. The payback period for this measure without incentives is 1.04 years. The justification for the measure is that this is a program component aimed at establishing a structured, continuous approach to helping customers improve energy performance, reduce costs, and achieve long-term operational efficiency. It is intended to have a very short payback to keep customers engaged and focused on longer-term savings. Its inclusion in the Plan is consistent with prior Board approvals.

  a) Performance-based incentives for strategic energy management programs are common in many jurisdictions. E1 introduced its incentives in 2021 to align with other regions (e.g., BC Hydro and Bonneville Power Administration), to help facilitate recruitment of

large industrial customers, encourage customers to complete energy efficiency projects, and reward them for the time and effort they invest in energy management. Since introducing these incentives, participation and savings in E1's program has roughly doubled, as captured in the 2020 and 2025 Custom Incentives DSM evaluation reports.

b) The Strategic Energy Management program component rewards customers with performance-based incentives for the significant time, effort, and resources they commit to the program throughout the year. This allows customers to better sell the benefits of the program to internal stakeholders and helps to provide justification for engagement in the program long-term. In many cases, customers re-invest the incentives into other energy efficiency efforts. Customers are coupling regular operational improvements with larger-scale capital projects that reduce customer costs and keep them focused on continuous improvement.

c) The costs noted in Table 37 of Appendix A of E1's 2027-2031 DSM Plan Application are the total program cost estimates. This includes the cost of hiring a Service Provider to educate and guide customers toward making operational changes that save them energy and the incentives paid to customers for energy savings achieved. The costs in Appendix A, Attachment 3, highlight the customer incentive portion of the total costs.

Request IR-05:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

With regards to Section 2.2.2.1 "Compliance with the 2025 BCA Decision":

(a) Pdf pg. 24 states: "E1 further notes that long-run marginal emissions rates have not been provided by NS Power, despite requests in December 2025 and February 2026. E1 understands that NS Power is consulting with the NSIESO on methodology and that this work is ongoing. E1 has calculated emissions impacts using the best available emissions information from NS Power's IRP, consistent with the approach taken in the 2023–2026 DSM Plan."

i) Has E1 had any discussions with the NSIESO and/or NS Power since February 2026 regarding long-run marginal emissions rates?

- **If so, please provide a summary of these discussions.**

ii) Please briefly summarize the approach taken in the 2027–2031 DSM Plan to calculate emissions impacts.

- **Please briefly summarize how the use of long-run marginal emissions rates would likely impact the results 2027–2031 DSM Plan emissions impacts calculations.**
  - **a) Please confirm whether this would affect the PAC scores for any measures proposed in the 2027-2031 DSM Plan.**
    - **A. If confirmed: Please identify the affected measures and impact on the related PAC scores.**

Response IR-05:

(a)

i) EfficiencyOne (E1) has not had any further discussions with NS Power or the Nova Scotia Independent Energy System Operator (NSIESO) since February 2026. E1 has requested the long-run marginal emissions rates, and NS Power has acknowledged the request. It is E1's understanding that NS Power continues to work with the NSIESO and will provide the emissions rates once available.

ii) Emissions impacts included in E1's 2027–2031 DSM Plan Application are calculated by multiplying the estimated net energy change associated with each measure, disaggregated by fuel type, by the corresponding emissions intensity for each fuel. The electricity emissions intensity was developed using the 2022 Evergreen Integrated Resource Plan (IRP) modelling results, from which annual emissions profiles and net-at-generator generation were used to derive a forward-looking annual grid emissions intensity. The resulting emissions impacts are summed to determine total GHG effects at the measure level. This calculation is performed for each applicable year - from initial measure implementation through the end of the measure's effective life - and then aggregated over time.

These results are subsequently consolidated across all measures to reflect total portfolio impacts.

- Using new long-run marginal emissions rates could result in different (higher or lower) CO_2e reductions than those included in the 2027–2031 Preferred DSM Plan Application. However, such a change would not have an impact on the Performance Targets, Investment, or Program Administrator Cost (PAC) results in the current Application.

a) Since emissions are not an input to the PAC calculations under E1's 2027–2031 DSM Plan methodology, the use of long-run marginal emissions rates would not impact the PAC results for any measures proposed in the Application.

   A. As confirmed in part ii) a) above, no measures in the 2027–2031 DSM Plan are affected, as emissions do not form part of the PAC calculations.

Request IR-06:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

With regards to Section 2.2.3.1 "Compliance with the 2026 DSM Extension Decision":

(a) Reference E-1, page 18 of 71 (pdf pg. 25) and Appendix A page 79 of 112 (pdf pg. 167), E1 states there is currently no double counting of savings between its demand response programs and NS Power's rate signals.

i) Please explain why E1 is confident that there is no double counting between its demand response program and NS Power's rate signals.

ii) E1 notes that it excludes customers enrolled in NS Power's Time-Varying Pricing pilot to maintain program clarity but does not refer to any other time differentiated rates, such as NS Power's time of day rate for customers with electric thermal storage units. Please explain whether these customers are excluded and if not, how program clarity is maintained.

(b) Pdf pg. 26 states: "In response to the concerns regarding Residential Behaviour, E1 has not included Residential Behaviour in its Preferred Plan."

i) Please identify the budgeted cost for the Residential Behaviour program for each year in E1's 2023-2025 DSM plan and 2026 Extension.

Response IR-06:

(a)

i) EfficiencyOne (E1) is confident there is no double counting of impacts from NS Power's rate signals within E1's reported available capacity from E1's Residential

Demand Response (DR) program component as E1's Evaluator crosschecks all DR participants with a list of NS Power's Time-Varying Pricing and Critical Peak Pricing (CPP) participants. Any E1 Residential DR participant that is participating in NS Power's Time-Varying Pricing (TVP) pilot which includes Time-of-Use (TOU) and CPP is removed from the evaluated results. E1's eligibility criteria for the Residential Demand Response program component has prohibited customers with a NS Power Time-of-Day (TOD) rate and as proposed in the 2027–2031 DSM Plan, new enrollments for Eco Shift are not proposed. E1 notes that the TVP pilot has been interrupted as a result of NS Power's cybersecurity breach, however since DR participants may opt to switch to a TVP rate in the future and after enrolling in DR, E1 will continue to monitor participants and ensure they are excluded from the DR evaluation.

ii) Please refer to part (a) i) of this IR response.

(b)

i) The budgeted costs for the Residential Behaviour program are noted below:

	Budget (Millions)
2023	$1.1[1]
2024	$2.2[2]
2025	$2.2[3]
2026	$2.1[4]

[1] M10473, Exhibit E-30, E1 2023-2025 DSM Resource Plan Compliance Filing, Appendix A, October 4, 2022, page 78 of 148.
[2] Ibid.
[3] Ibid.
[4] M12249, Exhibit E-1, Evidence, E1 2026 DSM Extension, April 30, 2025, Table 5 page 23 of 25.

Request IR-07:

<u>Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)</u>

Regarding Section 2.3 "Standardized Filing Framework" of the Application:

(a) Section 2.3.1 "The 2022 Integrated Resource Plan", pdf pgs. 28-29 state: "The Standardized Filing Framework directs that the Resource Plan identified in NS Power's Integrated Resource Plan ("IRP") will serve to inform the development of a Preferred DSM Plan by E1. The current Resource Plan is NS Power's 2022 Evergreen IRP, which includes 683.1 GWh of energy savings and 123.9 MW of demand savings from energy efficiency during the 2027–2031 period and 44.3 MW of demand response available capacity (excluding NS Power delivered demand response activities through rate design). However, as will be discussed further, while E1 considers the IRP scenario to represent the current assessment of the optimal level of DSM that is in the best interest of ratepayers for the long term, E1 must also consider short term affordability which is influenced by current economic landscape for Nova Scotia residents and businesses.

i) Please confirm that resource plan used to inform the development of E1's 2027-2031 DSM Plan incorporates the findings and conclusions from NS Power's 2025 IRP Action Plan Update.

- **If not confirmed, please explain.**

ii) Please describe how E1 has addressed the "Hybrid Peak Electrification Scenario" from NS Power's 2025 IRP Action Plan Update in its 2027-2031 DSM plan.

iii) Board staff notes that Table 8 of Exhibit E-1 (pdf pg. 64) shows that the E1's Preferred 2027-2031 DSM Plan allows for 435.4 GWh of first-year energy savings, 85 MW of peak demand savings, and 29.3 MW of demand response available capacity. These numbers are lower than those identified on pdf pg. 28-29 from the

2022 Evergreen IRP. Further, on pdf pg. 34 of Exhibit E-1, E1 states: "E1 also modelled a third scenario that reflected energy savings levels consistent with the IRP."

- **Please identify the estimated DSM investment over 2027-2031 that would be required to meet the targets noted from the 2022 Evergreen IRP.**

(b) Regarding "Appendix F – Proposed Updated Standardized Filing Framework" of the Application:

i) Page 7 of 13 of Appendix F (pdf pg. 413 of the application) states: "E1 will work with the NSIESO on IRP activities, which may include commissioning a DSM baseline study in advance of each DSM Potential Study to identify current stocks of electricity consuming devices in all market sectors." Please describe any work E1 and the NSIESO have completed to date related to commissioning of a DSM baseline study.

ii) Page 7 of 13 of Appendix F (pdf pg. 413 of the application) states: "E1 will work with the NSIESO on IRP activities, including the commission of a DSM Potential study in advance of each IRP exercise. The DSM Potential study identifies DSM resources that are achievable over the planning horizon, and will inform the development of Candidate Resource Plans for the IRP." Please describe any work E1 and the NSIESO have completed to date related to commissioning of a DSM Potential study.

iii) Page 7 of 13 of Appendix F (pdf pg. 413 of the application) states: "NSIESO will work with the DSM franchise holder to develop avoided cost calculations for demand side management resources." Please describe any work E1 and the NSIESO have completed to date related to developing avoided cost calculations for DSM resources.

Response IR-07:

(a) Yes. For the purposes of informing the development of the DSM Plan, specifically the levels of DSM (energy savings, demand savings and available capacity), EfficiencyOne (E1) understands there to have been no changes to the DSM levels contained in NS Power's 2025 Integrated Resource Plan (IRP) Action Plan as compared to the 2022 Evergreen IRP Update.

i) Please refer to part (a) of this IR response.

ii) Please refer to E1's response to SBA IR-05 part (a).

iii) As part of the development of the 2027–2031 DSM Plan, E1 modelled an energy efficiency scenario that reflected energy savings levels consistent with the IRP as part of the Round 2 modelling phase. The energy efficiency IRP scenario as modelled was cost effective and had a total investment amount of $464 million. As part of the earlier Round 1 modelling phase, E1 modelled a demand response scenario that reflected available capacity levels that were more closely aligned with the IRP at 40 MW and had a total investment amount of $47 million. For additional detail on the energy efficiency IRP scenario modelled as part of the 2027–2031 DSM Plan development, please refer to E1's response to CA IR-02, CA IR-09, CA IR-10, CA IR-11 and CA IR-12.

(b)

i) E1 has not commissioned a DSM baseline study. The purpose of a baseline study, in the context of informing a DSM Potential Study, is to ensure the market is effectively characterized (e.g., baseline equipment, technology saturation, customer behavior, and market conditions) to support accurate DSM potential projections. E1 anticipates undertaking a DSM baseline study for a future DSM

Potential study conducted over the 2027–2031 period. E1 is undertaking a DSM Potential Study in 2026 that differs from this practice for the following reasons:

- E1's primary objective for the 2026 DSM Potential Study is to inform the Nova Scotia Independent Energy System Operator's (NSIESO) 2026 IRP, which requires the study to be completed within a condensed timeline.
- DSM planning and modelling were previously undertaken to support the development of E1's 2027–2031 DSM Plan application. This work was informed by E1's most recent evaluation findings and consultation with DSM experts. Given the recency of this analysis, it provides a strong foundation for developing longer-term DSM potential projections.

Based on these considerations, E1 determined that foregoing a standalone DSM baseline study was a prudent approach that avoids expending additional time and ratepayer investment on duplicative analysis.

To establish baseline conditions for the 2026 DSM Potential Study, E1 will use a combination of program tracking data, external datasets, and advanced analytics to characterize energy use and market conditions. This methodology is intended to support near-term alignment with the proposed 2027–2031 DSM Preferred Plan while using calibrated modelling to project longer-term adoption trends and system impacts. The approach includes:

- Tracking energy-efficient installations through DSM programs;
- Leveraging Natural Resources Canada (NRCan) housing and energy datasets;
- Modelling end-use energy consumption using AMI and weather data to identify usage patterns and system characteristics; and

- Integrating multiple data sources, including NS Power data, surveys, census information, publicly available datasets, and jurisdictional scans, to assess baseline trends.

These insights will also be supported through detailed tracking of measure costs using project cost data.

ii) E1 has engaged a consultant to complete a new 25-year DSM potential study, scheduled to align with the timelines required by the NSIESO for its IRP. Work completed to date by E1 and its consultant includes defining the scope of work, confirming the measures and programs to be included, and initiating data collection. E1 has met with the NSIESO on several occasions to align priorities and expected outcomes, including clarifying required inputs and requesting updated load forecast data.

iii) E1's most recent engagement for updated avoided cost data was with NS Power, for the purpose of informing E1's 2027–2031 DSM Plan modelling. NS Power provided updated avoided costs to E1, from the 2022 Evergreen IRP in December 2025.

Request IR-08:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 3.2 "Energy Efficiency: Setting Appropriate Level of Energy Savings" of the Application:

(a) Please provide a copy of the jurisdictional scan completed by APEX, as referenced on pdf pg. 32 of the application.

(b) Please explain how the proposed increase in incentive percentage from 66% to 71% aligns with the activities the Demand-side management definition set out in s. 79A(b) of the Public Utilities Act and with the requirement to prioritize short-term affordability?

Response IR-08:

(a) Please refer to Attachment 1 of this IR response for the jurisdictional scan prepared by APEX that informed the level of energy savings for the energy efficiency resource.

(b) Section 79A(b) of the Public Utilities Act defines demand-side management to include activities, programs or plans relating to the efficient use of electricity (s. 79A(b)(i)), the conservation of electricity (s. 79A(b)(ii)), the alteration of consumption patterns to reduce demand during peak periods (s. 79A(b)(iii)), strategic electrification that reduces greenhouse gas emissions and electricity costs (s. 79A(b)(iv)), and the delivery of reductions in electrical energy or capacity that NS Power would otherwise be required to supply (s. 79A(b)(v)). The Preferred Plan's proposed portfolio — comprising energy efficiency programs, demand response, customer-sited solar PV, and enabling strategies — falls

within these definitions. The increase in customer incentives from 66 percent to 71 percent of total plan costs does not change the nature of the activities funded; rather, it reflects a deliberate choice to direct a greater share of the proposed DSM budget to customer-facing rebates and services that support those same efficiency and conservation activities. All programs for which incentives are paid remain activities that deliver measurable reductions in energy use and peak demand, consistent with the statutory definition.

The Preferred Plan was designed first and foremost to reduce electricity costs for customers and to prioritize short-term affordability. Three overall features of the proposed Plan are particularly relevant to this requirement. First, EfficiencyOne (E1) constrained total annual DSM investment to the 2026 Board-approved level of $63.75 million with no inflationary increases for any year of the 2027–2031 plan period, directly limiting near-term rate pressure on NS Power customers. Second, within that fixed budget, the increase in the customer incentive share from 66 percent to 71 percent ensures that a greater proportion of each dollar of DSM spending flows directly to customers as rebates and services, rather than to administrative or overhead. Third, the aggregate DSM investment of $318.75 million is projected to be fully paid through avoided utility costs by the end of 2032, confirming that the plan delivers durable long-term value while limiting short-term rate increases. The increase in the incentive percentage is therefore directly aligned with, and supports, the short-term affordability objective.

To:	Gina Thompson, Kate McDonald – EfficiencyOne
From:	Michael Goldman, Jodi Hanover, Matt Nelson – Apex Analytics, LLC
Subject:	Analysis and Recommendation for 2027-2031 Plan Savings Goals
Date:	May 22, 2026

1. Overview

EfficiencyOne (E1) seeks to deliver an affordable, climate-forward, and reliable energy future for Nova Scotia through efficiency programs. To advance this goal for the 2027-2031 Demand Side Management Plan (2027-2031 Plan), E1 retained Apex Analytics, LLC (Apex) to research and recommend reasonable savings goals that assist Nova Scotia in meeting its electricity demand, managing costs, and supporting Provincial environmental and sustainability goals, while maintaining affordability for customers.

E1 retained Apex to recommend a savings target range based on Nova Scotia's established, mature programs and current market conditions. Based on the methodology and analysis described in this report, Apex recommends a target range for net annual incremental electricity savings of **0.8%-1.0%** of forecast annual electricity sales for the 2027-2031 Plan. Based on available data from Efficiency Canada, the recommended savings rate would place Nova Scotia in the top third of Canadian provinces, maintaining its commitment to energy efficiency, but is lower than in previous plan periods and lower than some other provinces in recognition of increased program costs, and heightened awareness of affordability issues.

In preparing its recommendation, Apex reviewed savings values for jurisdictions with similar electric loads, climate, programs, and other characteristics. Apex's analysis also considered the need to maintain program delivery infrastructure and avoid significant disruptions that would negatively impact the vendor ecosystem and its ability to deliver on commitments to programs and its workforce.

Apex acknowledges that no two jurisdictions are identical, and that comparing savings goals and costs to acquire savings from historical plans to a future plan involves inherent limitations. Other factors, such as legislative mandates, applied evaluation methodologies and factors, and the ability of a jurisdiction to claim savings from unique programs (e.g., codes and standards), can also have a significant impact on savings targets in a given province or state. The recommended savings range takes into account current conditions and priorities for Nova Scotia, as well as these jurisdictional differences.

2. Savings Range Recommendation

A. Process and Scoring

The analytical approach used to identify appropriate comparison jurisdictions for Nova Scotia began with a preliminary screening based on broad climate similarity. Specifically, the analysis first reviewed jurisdictions with similar large-scale climate conditions by focusing on areas located within ASHRAE Climate Zone 6. This initial filter was intended to establish a baseline of seasonal weather, which is one of the largest drivers of energy consumption and, by extension, energy efficiency savings potential.

Using this first screen produced a set of potential comparison jurisdictions that showed comparable climate characteristics. These included the Canadian provinces of New Brunswick, Prince Edward Island, Newfoundland and Labrador, Québec, and Ontario, as well as several U.S. states, including Maine, Vermont, New Hampshire, New York, Michigan, and Wisconsin. While these jurisdictions share broad similarities with Nova Scotia, our approach recognized that general climate conditions alone were not sufficient to determine how comparable jurisdictions were in the context of energy efficiency program performance and savings opportunities.

The next phase of the analysis involved the development of a weighted model that incorporated multiple different variables to further refine the set of potential comparison jurisdictions. This model was designed to identify jurisdictions that most closely align with Nova Scotia across a range of variables that, based on professional experience and industry practice, serve as reasonable proxies for energy efficiency savings potential. The intent was to move beyond high-level climate screening and incorporate additional screening criteria.

The model evaluated jurisdictions across several major criteria such as local climate, building stock characteristics, energy pricing, socioeconomic conditions, and similarities in program design and delivery. Within each of these categories, multiple variables were analyzed.

Under the climate category, the analysis considered both the 10-year average heating degree days and the percentage of the population residing in rural areas. Heating degree days represent heating demand, while the rural population metric provides insight into potential variations in housing types, infrastructure, and access to energy services, all of which can influence energy consumption patterns.

Building stock characteristics were represented through variables including the percentage of homes constructed prior to 2000, the share of single-detached homes, and the distribution of heating system types. These factors collectively provide a proxy for the physical condition of the housing stock, the prevalence of retrofit opportunities, and the types of energy efficiency measures that are likely to be applicable or cost-effective.

In the energy category, the model incorporated average electricity cost as a key variable. Energy prices are known to influence customer behavior and program participation, as they impact both the economic attractiveness of efficiency measures and the overall potential for savings.

Socioeconomic conditions were considered through median household income and average energy burden. These variables were meant to capture the customer's ability to invest in efficiency improvements and the extent to which energy costs represent a significant share of household expenditures, which in turn can affect program uptake and design considerations.

Finally, the model included an element that assessed the degree of similarity between each jurisdiction's energy efficiency programs and those administered by E1. This assessment considered factors such as overall program size (e.g., budget), the focus on weatherization, the inclusion of behavioral programs, and how the programs were delivered. This ensured that potential comparison jurisdictions were also similar in the structure and scope of their energy efficiency efforts.

Each jurisdiction's value for a given variable was compared to the corresponding Nova Scotia value, and a score was assigned based on the relative proximity of the two. For example, if Nova Scotia had a 10-year average of 4,100 heating degree days and New Brunswick had a value of 4,500, the model would calculate the difference (400) and normalize it relative to the Nova Scotia value. The resulting score,

calculated as one minus the ratio of the difference to the Nova Scotia baseline (i.e., 1 - [400 / 4,100]), yields a similarity score of approximately 90.24 for that variable for New Brunswick in this example.

This scoring methodology was applied across all variables, enabling the development of aggregate scores that reflect overall similarity across the set of variables in the model. Each category was weighted based on Apex's determination of its relative importance. Through this approach, the analysis was able to narrow the field of candidate jurisdictions and identify those most comparable to Nova Scotia in terms of both underlying conditions and program similarity. Table 1 below shows the results of the model with New Brunswick, Prince Edward Island, and New Hampshire representing the most similar jurisdictions to Nova Scotia.

Table 1. Scoring of Comparable Jurisdictions

Jurisdiction	Score	Rank
New Brunswick	86.85	1
Prince Edward Island	82.04	2
New Hampshire	80.61	3
Newfoundland and Labrador	78.27	4
Maine	72.25	5
Vermont	65.96	6
Wisconsin	60.81	7
Ontario	60.78	8
Michigan	59.84	9
Quebec	59.31	10
New York	53.68	11

Point Savings Estimate

In order to develop a weighted average savings estimate, the Apex team used the scores developed in the previous exercise that determined how similar each jurisdiction was to Nova Scotia. The weight for each jurisdiction was developed by dividing its score by the sum of all the jurisdictions' scores, reflecting its relative importance (or similarity to Nova Scotia). If a state/province had a relatively high score (meaning more similar to Nova Scotia) it had a higher weight in the equation. Each state's/province's weight was multiplied by the most recent reported savings estimate from ACEEE[1] or Efficiency Canada[2].

Table 2. Savings Estimate from Weighted Jurisdictional Model Approach

Jurisdiction	Score	Savings	Weight	Weighted Savings
New Brunswick	86.85	0.46%	0.114	0.05%
Prince Edward Island	82.04	1.11%	0.108	0.12%
Maine	72.25	0.86%	0.095	0.08%
Newfoundland and Labrador	78.27	0.32%	0.103	0.03%

[1] American Council for an Energy-Efficient Economy (ACEEE) 2025 State Energy Efficiency Scorecard

[2] Efficiency Canada 2024 Canadian Energy Efficiency Scorecard: Provinces and Territories

Jurisdiction	Score	Savings	Weight	Weighted Savings
Vermont	65.96	1.43%	0.087	0.12%
New Hampshire	80.61	0.82%	0.106	0.09%
Quebec	59.31	0.57%	0.078	0.04%
Ontario	60.78	1.21%	0.080	0.10%
New York	53.68	1.20%	0.071	0.08%
Michigan	59.84	1.74%	0.079	0.14%
Wisconsin	60.81	0.45%	0.080	0.04%
	Total Weighted Savings			0.90%

Table 2 shows that applying this methodology produces an average annual savings level of approximately 0.90%. The weighting prioritizes jurisdictions most comparable to Nova Scotia in terms of program structure, budget scale, and regulatory context. As a result, the outcome aligns closely with observed savings levels in core peer jurisdictions, which provide a range of 0.46% to 1.11% in the three jurisdictions most similar to Nova Scotia.[3] Based on this point estimate and the range observed across peer jurisdictions, Apex applied professional judgment to establish a recommended savings range of 0.8%-1.0%, reflecting reasonable variability in acquisition costs, program maturity, and affordability conditions over the five-year planning horizon.

B. Sector Comparisons

With respect to the savings split between Business, Non-Profit, and Institutional (BNI) and Residential sectors, Apex analyzed variations across jurisdictions in terms of savings from each of the sectors. Table 3 shows that jurisdictions similar to Nova Scotia, including New Brunswick, New Hampshire, Maine, and Vermont, tended to be skewed towards BNI savings. Based on Apex's analysis, this is attributable to large discrepancies in the cost of BNI savings vs. residential, with BNI savings being significantly less expensive on a per-unit basis.

[3] Of note, while New Brunswick's savings goals are on the low end of this range, New Brunswick's savings goals are inclining over time, corresponding to legislatively mandated targets. Energy efficiency goals in New Brunswick were in the 0.6-0.7% range for 2025-2027 and will increase to .75% for the fiscal year 2028-2029 (https://laws.gnb.ca/en/document/cr/2022-74). Additionally, New Brunswick's energy efficiency program funding sources include a small percentage of federal funding (2%) and some amount of provincial funding (to be used, in part, to fund non-electric fuel measures), along with ratepayer funds. Whether the funding is from taxpayers or ratepayers is not relevant to this savings goal comparison, as the programs ultimately are paid for by and benefit the citizens of the province in either instance.

Table 3. Savings Split by Sector

	MA (Statewide)	New Hampshire	Efficiency Maine	Efficiency Vermont	Efficiency PEI	New Brunswick
Resi	32%	18%	5%	32%	74%	22%
BNI (C&I)	53%	78%	70%	68%	26%	78%
Low Income	15%	3%	3%			
Multifamily						
Midstream			22%			
Total	100%	99%	100%	100%	100%	100%

C. Application to Nova Scotia

Following its jurisdictional comparison analysis, Apex then considered the unique circumstances for Nova Scotia based on its historical electricity demand, climate goals, and needs as a province. Apex examined Nova Scotia's priorities and E1's capabilities and capacity to deliver energy efficiency programs. Nova Scotia is committed to strengthening system reliability and resiliency through efficiency and demand response measures. The programs are also designed to drive greenhouse gas reductions and align with provincial environmental and sustainability goals. The energy efficiency programs in Nova Scotia are well-established and able to deliver on commitments in the near-term. These factors support Apex's conclusion that Nova Scotia has the capability to meet or exceed the energy efficiency savings targets achieved in comparable jurisdictions.

Apex also analyzed the costs of acquisition to assess how to balance the value of energy efficiency with customer affordability considerations. The cost per unit for energy efficiency has gone up in this proposed Plan, as it has for energy efficiency programs across North America. This is due to multiple factors. Recent evaluation results have reduced the savings for some measures, while the associated costs remain the same, if not higher, due to inflationary factors. Programs that were historically a source of lower cost savings, such as residential behavior programs and lighting, have been phased out. Heat pumps represent an increasingly significant portion of the portfolio that provide multiple benefits including greenhouse gas reduction but also involve higher per-unit costs and generate low or no incremental kWh savings.

Additionally, the cost of living has gone up, along with the cost of materials and labor. Market pricing has been affected by price signals and customer expectations that were established during the period of federal and provincial funding programs, which have since been discontinued. E1's support for low-income customers and equity communities has not waivered, but the unit cost of savings from low-income customers tends to be higher than market rate customers. Despite these economic challenges, Apex's analysis confirms that energy efficiency remains the most cost-effective resource for meeting electricity demand and managing system costs when compared to supply-side alternatives.[4]

Nova Scotia has a mature program delivery infrastructure. Based on market analysis, reducing program goals significantly could cause disruption to the energy efficiency market and vendor ecosystem that

[4] NSPI Resource Options Study, Nova Scotia Power, July 2019 (https://www.nspower.ca/docs/default-source/irp/attachment-2-nspi-e3-supply-options-study.pdf?sfvrsn=d37f92c6_1).

supports program delivery. Substantial reductions in savings goals could cause market participants to exit the energy efficiency sector, leading to reduced competition, upward pressure on pricing, and degraded customer service quality. Rebuilding program infrastructure after a major market disruption would require significant time and resources and could result in extended periods of reduced program effectiveness. Maintaining program continuity serves to preserve the trained energy efficiency workforce and established customer service standards that support effective program delivery.

Based on its analysis, Apex concludes that Nova Scotia's commitments to reliability and resiliency through efficiency and demand response measures, the continued cost-effectiveness of energy efficiency relative to supply-side alternatives despite higher per-unit acquisition costs, and the importance of maintaining energy efficiency delivery infrastructure, support savings goals that are within the range of comparable jurisdictions.

3. Conclusion

After analyzing comparable jurisdictions in North America, as well as E1's historical achievements, market demand, and organizational capability, Apex recommends a net savings target of 0.8%-1.0% of sales for the 2027-2031 Plan, which is within the range of similar jurisdictions. This target is lower than Nova Scotia's targets in previous planning periods due to increased per-unit acquisition costs, ratepayer affordability considerations, and the lower kWh savings resulting from a mature portfolio, but is sufficient to maintain the energy efficiency market infrastructure and advance provincial energy and environmental priorities. Where the 2027-2031 proposed savings goal falls within the range will be determined by E1 after consideration of additional factors, such as changes in unitary costs over time, affordability concerns, and market penetration. Apex also recommends an up to 30%/70% split between residential and BNI savings, based on the lower cost to acquire BNI savings. Ultimately, the recommended savings targets balance the energy efficiency and affordability needs of Nova Scotia for 2027-2031.

Request IR-09:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

(a) Pdf pg. 32 states that 71% of the Preferred Plan is for customer incentives. Please confirm, or explain otherwise, that it is approximately $239.1 million for customer incentives.

Response IR-09:

(a) The total customer incentives in the proposed 2027–2031 DSM Plan are $225.01 million or 70.6 percent of the total investment of $318.75 million. Please refer to EfficiencyOne's response to part (a) of IG IR-12.

Request IR-10:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Pdf pg. 32 states that the Preferred Plan's energy savings will reduce 0.8% of NS Power's load. Please confirm, or explain otherwise, that the 0.8% is the expected total cumulative energy savings to be achieved from 2027-2031 rather than 0.8% per year.

(a) Is the 0.8% of NS Power's load, the total cumulative load NS Power forecasts for 2027-2031 or is it NS Power's load for 2025?

Response IR-10:

(a) The 0.8 percent is calculated based on NS Power's cumulative load forecast for the 2027–2031 period. Although there are fluctuations from one year to the next, the overall average for the Plan is reflective of 0.8 percent.

Year	First Year Net Savings | Energy Savings (GWh)	2025 NS Power Load Forecast[1] (GWh)	First Year Net Savings | Energy Savings % of Load
2027	121	11,193	1.1%
2028	101	11,226	0.9%
2029	78	11,159	0.7%
2030	70	11,130	0.6%
2031	65	11,125	0.6%
Average	87	11,167	0.8%
Cumulative	435	55,833	0.8%

[1] M12349, Nova Scotia Power, 2025 Load Forecast Report, June 27, 2025, page 10.

Request IR-11:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Reference to Exhibit E-1, page 27 of 71 (pdf pg. 34):

E1 notes that its preferred plan maintains a trajectory towards the IRP's long-term savings levels while prioritizing short-term affordability considerations for the period 2027-2031 given the current economic context.

(a) Does E1 anticipate a need for "catch-up" following the 2027-2031 period to maintain this trajectory?

Response IR-11:

(a) Please refer to EfficiencyOne's response to part (g) of Synapse IR-10.

Request IR-12:

<u>Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)</u>

Regarding Section 3.3 "Demand Response" of the Application:

(a) Pdf pg. 34 states: "The demand response design in the 2027–2031 DSM Plan was informed by a combination of observed implementation experience, updated modelling assumptions, evaluation insights, DSMAG member feedback, and alignment with system planning objectives."

i) Please describe the updated modelling assumptions related to demand response design in the 2027-2031 DSM Plan compared to those used in the 2023-2025 DSM Plan and 2026 DSM Extension.

- **As it relates to E1 Administrative Costs, under the "Key Model Assumptions" tab in Exhibit E-1(i) Appendix A – Attachment 1, E1 states: "Demand Response administrative costs have been updated from the 2023-2025 Plan model with information from E1 experience delivering demand response."**
  - **a) Please describe E1's experience delivering demand response.**
  - **b) Please describe specifically how the demand response administrative costs have been updated from the 2023-2026 DSM Plan.**
  - **c) Please identify the amount by which demand response administrative costs have changed from the 2023-2026 DSM Plan.**

(b) Pdf pg. 35 states: "DSMAG member feedback, played a significant role in shaping the demand response portfolio. In prior planning rounds, members raised concerns regarding the scale, achievability, and cost-effectiveness of proposed demand response investments. The 2027–2031 Plan responds to these concerns by moderating demand response investment levels relative to earlier scenarios, adopting more conservative ramp-ups, and ensuring that proposed capacity targets remain within a range consistent with system needs identified through integrated resource planning."

i) Please provide a detailed summary of DSMAG member feedback related to demand response design in the 2027-2031 DSM Plan.

(c) Please explain why the Demand Response "Investment" amounts in 2027-2031 from Tables 9 to 13 in Appendix A of the application (pdf pgs. 117-121) and in Table 47 (pdf pg. 170) do not match the 2027-2031 PAC costs noted in tab "19c. BC Ratios by Year Avg" of Exhibit N-1(iii) Appendix A, Attachment 4.

(d) Pdf pg. 35 states: "E1's Preferred Plan does include the Residential program component. Although it is not required that the program component itself is cost effective, E1 does understand that a justification for inclusion of measures that do not pass must be provided. While the Residential Demand Response (Eco Shift) program component does not yet meet the standard cost-effectiveness threshold, there have been noted improvements."

i) Please provide the PAC score for the Residential Demand Response program component for each year from 2027 to 2031.

ii) Please provide the PAC score for the BNI Demand Response program component for each year from 2027 to 2031.

(e) Pdf pg. 36 states: "Experience in peer jurisdictions suggests Nova Scotia is at an earlier stage of market development but following a similar trajectory. Cost-effectiveness is expected to improve over time as participation grows, technologies mature, operational processes are refined, and program design evolves alongside system needs."

i) it relates to Residential Demand Response, please provide documentation to support E1's claim that "Experience in peer jurisdictions suggests Nova Scotia is at an earlier stage of market development but following a similar trajectory".

(f) As it relates the number of Demand Response participants noted in tab "8. Participants" of Exhibit N-1(iii) Appendix A, Attachment 4:

i) Please confirm whether the number of participants per year represents the number of new participants in the program each year, or the cumulative number of participants in the program at the end of each year.

ii) Please provide a breakdown of the number of participants for each year from 2027 to 2031 showing the number of residential and BNI participants.

iii) Please provide a breakdown of the number of participants for both 2024 and 2025 showing the number of residential and BNI participants.

(g) As it relates to Exhibit N-1(iii) Appendix A, Attachment 4:

i) Regarding tab "19a. BC Ratios Cost Cat Avg", please provide the Demand Response program PAC score with the costs and benefits associated with the "DLC – Thermostats" program component excluded.

ii) Regarding tab "19a. BC Ratios Cost Cat Avg", please provide the Demand Response program PAC score with the costs and benefits associated with both the "DLC – Thermostats" and "DLC – Water Heating" programs component excluded.

iii) Based on Board staff's review of tab "3a. Achiev Pot_Opt_Meter Avg" and tab "4a. Achiev Pot_Opt_Gen Avg", it would appear that most of the MW savings derived

from the Demand Response program are a result of "C&I Curtailment" and "C&I Loadshift to BUGs". Please confirm.

- **If not confirmed, please explain in the context of the Figures contained in the tabs.**
- **If confirmed:**
  - **a) Please describe the specific reasons for the disproportionate amount of spending on "DLC – Thermostats" and "DLC – Water Heating" programs components in each of 2027 to 2031 compared to "C&I Curtailment" and "C&I Loadshift to BUGs" spending.**
  - **b) For each of 2027 to 2031, please provide the $ spent/MW saved for each of the "DLC – Thermostats", "DLC – Water Heating", "C&I Curtailment" and "C&I Loadshift to BUGs" program components.**

(h) In the Board's decision for E1's 2026 DSM Extension (Matter M12249), the Board stated: "That said, the Board notes that E1 should be fully prepared to address the questions raised in this proceeding about potential overlap with NS Power's Critical Peak Pricing Program and the targeting of constrained areas of the transmission and distribution system in its application. If it fails to adequately address these issues, this may complicate the approval of its DSM Plan. The Board expects NS Power to cooperate fully with E1 in exploring these issues." On pdf pg. 167 of Exhibit E-1 of the current application, E1 states: "E1 has initiated discussions with NS Power to further collaborate on both locational demand response and the stacking of E1's demand response with rate signals. While there is not currently double counting of savings between E1's demand response program and NS Power's rate signals, E1 and NS Power recognize this requires ongoing efforts to determine if and how these two programs should work together. E1 expects these

discussions to continue with the outcome being a proposed resolution agreed upon by both organizations. E1 is committed to continue to work through a solution that remains in the best interest of ratepayers. To support work on both locational demand response and the interplay between E1's demand response program and NS Power's TVP, E1 has included these areas of exploration and collaboration in its Innovation Framework, Process and Plan for 2027–2031, provided as Attachment 5 to Appendix A."

i) Please confirm that any NS Power customers participating in NS Power's TVP and CPP programs are excluded from participation in E1's Demand Response program.

- **If not confirmed, please explain how "double counting" between the programs is prevented.**

ii) Please identify the timeline for when E1 intends to have these issues resolved.

(i) As it relates to E1's collaborative efforts with NS Power on locational demand response and stacking of E1's demand response with NS Power's rate signals, pdf pg. 26 of Exhibit E-1 states: "E1 has included both of these topics for development and research efforts under innovation as highlighted in both Appendix A, section 9.4 and in the Innovation Framework, Process and Plan for 2027–2031 included as Attachment 5 to Appendix A."

i) Are the total costs for these "development and research efforts under innovation" as noted in the "Demand Response" line and the "Locational DSM" line of "Table 1: Projected Direct Expenditures by Focus Area" in Appendix A Attachment 5 (pdf pf. 221)?

- **If not:**
  - **a) Please identify the forecast annual costs for these efforts for each year from 2027 to 2031.**
  - b) **Please identify the other issues that Table 1 "Demand Response" and "Locational DSM" efforts will address.**

Response IR-12:

(a)

i) Please refer to Attachment 4 of EfficiencyOne's (E1) response to NSEB IR-38 for the 2027–2031 DSM Plan demand response inputs.
Please refer to Attachment 1 of this IR response for the 2026 Extension DR inputs.
Demand response inputs for the 2023–2025 DSM Plan can be found as Attachment 1 of E1's response to Synapse IR-24 in matter M10473.[1]

-

a) E1 included demand response for the first time in its 2023–2025 DSM Plan and experienced a number of challenges in launching the new DSM resource including building customer awareness and retaining customers from one season to the next. In the Residential Demand Response program component specifically, quality concerns with domestic hot water direct load controllers and lower-than-expected adoption of certain demand response devices impacted results. E1 has used its experience and the lessons learned from its first three seasons to inform its approach moving forward. Further details and analysis of the Demand Response program in 2023–2025 are provided in DSM Quarterly and Annual Progress Reports that were filed with the Nova Scotia Energy Board over the course of the three years.

b) Demand response administrative costs can broadly be considered any non-incentive costs incurred by E1. Accordingly, this response addresses all non-incentive cost components. Please refer to E1's response to IG IR-12, Attachment 3 for the expenses categories.

[1] M10473, E-14-(iii), E1's 2023-2025 DSM Plan Application, Synapse IR-24, Attachment 1, April 29, 2022

In the 2023–2025 DSM Plan, demand response cost assumptions were largely developed by Guidehouse, as E1 did not yet have direct experience delivering demand response programs. Since then, E1 has successfully launched and expanded demand response programs. As a result, cost assumptions for the 2026 DSM Extension and the proposed 2027–2031 DSM Plan have been updated to reflect E1's actual program delivery experience.

Table 1 of this IR response summarizes key considerations used to inform demand response non-incentive cost assumptions in the 2027–2031 DSM Plan.

Table 1: Demand Response Non-Incentive Cost Considerations

Cost Category	E1 Cost Considerations
Program Administration Annual costs associated with program management, including E1 staffing, overhead, and evaluation activities.	Updated assumptions reflect required staffing levels and opportunities for cost sharing with energy efficiency programs. Updated evaluation costs considered E1's evaluation contract and the anticipated scope of demand response evaluation.
Program Delivery Costs paid to third-party service providers, including demand response management system vendors and the BNI Curtailment ("Smart Synergy") service provider.	Assumptions are informed by current contract terms, durations, and expected future cost changes (e.g., inflation, efficiencies, or delivery model adjustments). Some of these costs were previously categorized under "O&M Costs" in the 2023–2025 Plan.
Marketing & Recruitment Costs related to customer acquisition, outreach, and education.	Updated assumptions reflect required campaign scale based on recruitment targets, as well as supporting materials such as websites, and program documentation.
Technology Enablement Costs associated with customer equipment (e.g., smart thermostats and water heater controls) and installation.	Assumptions consider equipment type, recent procurements/contracts, installation costs, and opportunities for cost sharing across programs.

Cost Category	E1 Cost Considerations
Program Development One-time program start-up costs.	Applied only to the 2023–2025 DSM Plan and are not included in ongoing cost assumptions.

Detailed input assumptions for each cost category are provided in the Demand Response (DR) Input workbooks for each Plan (please refer to part (a)(i) of this IR response).

c) Please refer to E1's response to Synapse IR-90 part (a).

(b) Please refer to E1's response to NSEB IR-16.

i) Please refer to part (b) of this IR response.

(c) The difference between the investment amounts and the BC Ratio costs is due to the amortization of upfront costs for the BC Ratio costs.

As part of the benefit cost ratio calculation, the following costs are amortized over ten years (the program life of all DR options): program development costs, marketing & recruitment costs, and technology enablement costs. This is because these are one-time upfront costs that enable benefits over the lifetime of the program – the amortization allows costs and benefits to be treated symmetrically. This amortization of upfront costs is not applied to E1's investment.

(d)

i) and ii)

Please refer to Table 2.

Table 2: Annual Residential and BNI DR PAC results

Year	PAC - Res DR	PAC - BNI DR
2027	0.9	2.9
2028	0.5	1.6
2029	0.8	2.7
2030	0.7	2.3
2031	0.6	2.4

(e)

i) Please refer to E1's responses to CA IR-04 and CA IR-06.

(f)

i) The participant count reflects the total number of active participants each year, including both new entrants and those who have continued from previous years.

ii) Please refer to Table 3 of this IR response.

Table 3: Residential and BNI Demand Response participation (2027 – 2031)

	Residential DR	BNI DR
2027	10,044	169
2028	9,844	173
2029	9,646	173
2030	9,454	175
2031	9,266	175

iii) Please refer to Table 4 of this IR response.

Table 4: Residential and BNI Demand Response participation (2024 – 2025)

	Residential DR	BNI DR
2024	353	76
2025	3,676	143

(g)

i) The PAC result with "DLC – Thermostat" excluded is 2.18. This reflects BNI DR and residential water heating from the Preferred Plan.

ii) The PAC result with "DLC – Thermostat" and "DLC – Water Heating" excluded is 2.37. This value reflects only BNI DR from the Preferred Plan and matches the Alternate Scenario.

iii) Confirmed.

- N/A
-

a) The difference in spending reflects the different delivery models and maturity of the residential and BNI demand response offerings. Residential DR is delivered through a large number of smaller customer-side devices. This requires customer engagement, device enrollment, technology integration, platform costs, dispatch coordination, customer support, and measurement and verification across a distributed participant base. As a result, residential DR has a higher delivery cost per MW than larger BNI resources. By comparison, Commercial & Industrial (C&I) Curtailment and C&I Loadshift to backup generators (BUGs) can deliver larger curtailment amounts through a smaller number of participants. This creates an efficient delivery pathway, with lower program administration and acquisition costs per MW of capacity.

The spending on DLC – Thermostats and DLC – Water Heating reflects that Eco Shift remains a developing residential demand response platform. The program is not yet fully cost-effective, but early-stage residential DR programs require several years of customer recruitment, system integration, operational testing, and refinement before performance and economics stabilize.

During the 2027–2031 Plan period, E1 expects BNI demand response to provide the majority of DR capacity because it is a more cost-effective resource. Spending on DLC – Thermostats and DLC – Water Heating

reflects the cost of maintaining and improving the existing residential DR platform, preserving residential demand-side flexibility, and supporting continued operational improvements so that the resource can contribute to peak reduction and system resilience over time.

b) See Table 5.

Table 5: $ Spent / MW by DR Program Component

Year	DLC - Thermostats	DLC - Water Heating	C&I Curtailment	C&I Loadshift to BUGs
2027	544,148	457,978	185,246	185,481
2028	552,325	355,485	180,880	181,174
2029	560,343	367,762	177,439	177,680
2030	568,541	379,212	174,629	174,848
2031	576,920	392,224	172,334	172,593

(h)

i) Please refer to E1's response to NSEB IR-06.

ii) E1 does not have a specific timeline identified on when this issue will be resolved.

(i)

E1 confirms that the Innovation allocations identified under both the "Demand Response" and "Locational DSM" lines are inclusive of these efforts.

a) Not applicable

b) In addition to the activities related to locational demand response and the stacking of rate-based and incentive-based programming, the "Demand Response" and "Locational DSM" investment allocations also include the other "Key Activities" identified in Appendix A, Attachment 5 (PDF page 221–224).

Request IR-13:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 3.4 "Solar-PV":

(a) Pdf pg. 40 and 41 discusses solar-PV installations exclusively for residents of Mi'kmaw communities and that the program will add 200 installations for the DSM 2027-2031 years. Please confirm or explain otherwise that this solar-PV offering has an estimated total cost of about $2.9 million.

(b) Reference to Exhibit E-1, page 34 of 71 (pdf pg. 41), E1 notes that any expansion of its Solar-PV program to other customer segments in future DSM plans would be subject to cost-effectiveness analysis and Board approval.

i) Given the information that E1 provided in its application suggesting that the Solar-PV program is cost-effective, what is the basis for E1's suggestion that the program may be not be cost-effective in the future if rolled out to other customer segments?

Response IR-13:

(a) The solar-PV program total investment for the proposed 2027–2031 Preferred DSM Plan is $2.8 million.[1]

(b) EfficiencyOne (E1) did not intend to suggest with this statement that solar-PV would not be cost-effective in the future if rolled out to other customer segments. Rather E1's intent was

[1] M12780, E'1s 2027–2031 DSM Resource Plan Application, Table 9: 2027–2031 DSM Preferred Plan Savings and Investment by Program Component, Evidence

to acknowledge its understanding that any consideration of expansion in a future DSM Plan would be subject to cost effectiveness testing and Board approval.

i) Please refer to part (b) of this IR response.

Request IR-14:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Please provide a breakdown in 5-year increments from 2027 to the end of the forecast benefits period of the anticipated preferred plan lifetime benefits of $682.5 million.

Response IR-14:

Please see the table below for a breakdown in five-year increments from 2027 to the end of the benefit period representing the DSM Plan's lifetime benefits of $682.5 million. Please note the total of the table below may not sum exactly, as there may be differences due to rounding.

DSM Plan Lifetime Benefits Period	DSM Plan Lifetime Benefits ($M)
2027–2031	$229.4
2032–2036	$261.2
2037–2041	$121.5
2042–2046	$60.5
2047–2051	$9.1
2052–2056	$0.5
2057–2061	$0.2
Total: 2027–2061	**$682.5**

Request IR-15:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 3.5 "Strategic Electrification" of the Application:

(a) Pdf pg. 42 states: "E1 understands from DSMAG members that strategic electrification remains an important area for exploration to determine how it can cost effectively be included in future DSM Plans. To support this objective, E1 has allocated investment within its Enabling Strategies budget specifically for strategic electrification development and research. This investment will support: (1) market research and technology assessment to identify emerging strategic electrification opportunities with improved economics; (2) pilot programs to test delivery approaches and gather real-world performance data; (3) collaboration with the NSIESO on future IRP development to better quantify system benefits; and (4) ongoing evaluation of how changes to avoided costs, particularly capacity values, may improve the cost-effectiveness of strategic electrification in future plan periods."

i) Please provide a detailed summary of the feedback received from DSMAG members related to strategic electrification.

ii) Please identify the specific cost allocated in the Enabling Strategies budget for strategic electrification development and research for each year from 2027 to 2031.

Response IR-15:

(a)

i) Please refer to EfficiencyOne's (E1) response to NSEB IR-16.

ii) The projected direct expenditures for strategic electrification under the Innovation Framework, Process and Plan for 2027–2031 are set out in Table 1 of Appendix A, Attachment 5 of E1's 2027–2031 DSM Resource Plan Application as follows:

Table 1: Projected Direct Expenditures by Focus Area

Focus Area	DSM Direct Expenditure ($)					
	2027	2028	2029	2030	2031	Total ($)
Demand Response	160,650	178,815	123,175	110,250	111,500	684,390
Demand Flexibility	183,600	204,360	221,715	198,450	200,700	1,008,825
Strategic Electrification	45,900	51,090	24,635	22,050	22,300	165,975
Market Transformation	22,950	25,545	24,635	22,050	22,300	117,480
Locational DSM	45,900	51,090	98,540	88,200	89,200	372,930
Total Direct ($)	**459,000**	**510,900**	**492,700**	**441,000**	**446,000**	**2,349,600**

Additionally, Table 2: Key Activities by Focus Area of Appendix A, Attachment 5 provides the innovation goals, justification and key activities for each of the key focus areas, inclusive of strategic electrification.

Request IR-16:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 3.6 "Enabling Strategies" of the Application:

(a) Pdf pg. 43 states: "In addition to reducing total investment through prioritization, E1 has responded to DSMAG member comments regarding Enabling Strategies."

i) Please provide a detailed summary of the feedback received from DSMAG members related to enabling strategies.

Response IR-16:

(a)

i) The proposed 2027–2031 DSM Plan was developed through multiple stakeholder engagements facilitated between EfficiencyOne (E1), and the Demand Side Management Advisory Group (DSMAG). To encourage participation in open dialogue through the DSMAG, stakeholder input and submissions are managed with confidentiality consistent with the DSMAG Terms of Reference. This approach ensures stakeholders can share their opinions and positions on a without prejudice basis. This approach has been effective in establishing a collaborative environment for dialogue and decision-making.

The Terms of Reference of the DSMAG provide that:

> "…., all submissions, comments, and/or positions taken by any Members in the DSMAG meetings or technical sessions shall be considered as confidential by Members and shall not be reproduced or made public,

directly or indirectly, by any Members, including any future regulatory proceeding."[1]

The current version of the DSMAG Terms of Reference was filed with the Nova Scotia Utility and Review Board on September 20, 2021.[2]

[1] M09096, Document No. 84486, DSMAG Revised Terms of Reference, September 20, 2021, page 7
[2] Ibid.

Request IR-17:

<u>Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)</u>

Regarding Section 4 "Affordability" of the Application:

(a) Figures 2 and 3 on pdf pg. 46 illustrate the expenditures for the Preferred 2027-2031 DSM Plan and the 2026 DSM Extension.

i) Please provide the data for the development for Figure 2, broken down by program year.

ii) Please provide a breakdown of the salaries, benefits and training expenditure by component for Figure 2.

iii) Please provide a breakdown of full-time equivalent employees (FTEs) by program year and explain the reason for any changes.

iv) Please provide the current FTE count for E1 and explain any changes between the existing count and the FTEs contemplated for the preferred plan.

v) Please describe what is included in "program support".

vi) Please identify each of the following as of December 31, 2023, 2024 and 2025, and describe the reasons for any year over year increases:

- **E1's total full-time equivalent (FTE) staff complement**
- **E1's total salary burden (exclusive of costs related to employee benefits)**
- **E1's total employee benefits burden**
- **The total spent on E1 staff training in 2023, 2024, and 2025.**

vii) Please identify each of the following forecasts as of December 31, 2026, 2027, 2028, 2029, 2030 and 2031, and describe the reasons for any forecast year over year increases:

- **E1's total FTE staff complement**
- **E1's total salary burden (exclusive of costs related to employee benefits)**
- **E1's total employee benefits burden**
- **The total forecast spending on E1 staff training in 2026, 2027, 2028, 2029, 2030 and 2031.**

viii) On pdf pg. 56, E1 states: "To manage overall investment levels in the Preferred Plan, E1 has reduced full-time equivalent (FTE) staffing in the 2027–2031 Preferred Plan to 106.7 as compared to 114.3 in the 2026 DSM Extension." Figure 2 show an average "Salaries, benefits and training" expense in the 2027-2031 DSM plan of $12.7M, while Figure 3 shows $11.9M for "Salaries, benefits and training" in the 2026 DSM extension. Given the statement from pdf pg. 56, please explain the increase in "Salaries, benefits and training" expense from the 2026 DSM extension.

ix) On pdf pg. 55 of Exhibit N-1, E1 states: "Benchmarking – E1 ensures its costs are aligned with those of other similar industries, organizations, and DSM administrators, where appropriate, through market research and market comparisons prepared by independent third parties. E1 worked closely with subject matter experts to examine current market conditions when considering annual employee compensation changes."

- **Please provide a copy of these benchmarking studies comparing E1's total forecast staffing complement, salary burden, employee benefits burden, and staff training budgets for 2027 to 2031 to those of other DSM administrators.**

- **Please provide a copy of the subject matter expert reports related to proposed annual compensation changes in the 2027-2031 Preferred DSM plan.**

x) Please identify the types of expenditures that are included in the "Program Support" category noted in Figures 2 and 3.

(b) Regarding Section 4.3 "DSM Continues to Provide Lasting Benefits with a Short Payback Period": Pdf pg. 48 states: "A short payback period that provides fully funded DSM benefits no later than the end of 2032 is in the best interests of ratepayers as it leverages the lower costs associated with present-day investment prices and mitigates the long-term effects of inflation and rising costs – as illustrated in Figure 4."

i) Please provide the spreadsheet model used to produce Figure 4 complete with all formulae intact.

(c) Regarding Section 4.4 "DSM Continues to be the Least Risk Option": Pdf pg. 48 states: "DSM is a low-risk energy investment as there is: Certainty with respect to the level in investment; No unexpected costs associated with an investment in DSM; and No variability in the cost of DSM during each Plan term."

i) Does E1 agree that there are risks associated with the proposed 2027-2031 DSM Plan related to the plan not achieving its forecast benefits?

- **If not, please explain.**
- **If so, please characterize these risks.**

(d) Regarding Section 4.5 "Rate and Bill Considerations & Rate and Bill Impact Analysis (RBIA) for 2027-2031":

i) Pdf pg. 49 states: "E1's RBIA for the Preferred Plan demonstrates that participants in DSM benefit from bill savings. The reductions in energy use and demand achieved by participants more than outweigh any rate impacts associated with DSM."

- **Please confirm whether the Table and Figures in this section show rate and bill impacts for only DSM participants or for all NS Power customers.**
  - **a) If "for only DSM participants":**
    - **i. Please provide a revised Table 6 and revised Figures 5 and 6 to show average rate and customer bill impacts for non-DSM participants.**
      - **For the average NS Power residential non-DSM participant customer, what dollar amount does the 2027-2031 DSM Plan average bill impact represent? (if E1 does not know the annual electricity use of NS Power's average non-DSM participant customer, please provide this analysis for two separate customers: a) one who uses 6,000 kW/hr of electricity per year, and v) one who uses 12,000 kW/hr of electricity per year).**
  - **b) If "for all NS Power customers":**
    - **i. Please provide a revised Table 6 and revised Figures 5 and 6 to show average rate and customer bill impacts for only DSM participants.**
    - **ii. Please provide a revised Table 6 and revised Figures 5 and 6 to show average rate and customer bill impacts for non-DSM participants.**

- **For the average NS Power residential non-DSM participant customer, what dollar amount does the 2027-2031 DSM Plan average bill impact represent? (if E1 does not know the annual electricity use of NS Power's average non-DSM participant customer, please provide this analysis for two separate customers: a) one who uses 6,000 kW/hr of electricity per year, and v) one who uses 12,000 kW/hr of electricity per year).**

- **Please provide a revised Table 6 and revised Figure 6 to show average rate and customer bill impacts of the preferred 2027-2031 DSM plan over 2027-2031 for:**
  a) **DSM participants, and**
  b) **Non-DSM participants.**
- **Please provide a revised Figure 7 and 8 to show average rate and customer bill impacts of the preferred 2027-2031 DSM plan over 2027-2031.**
- **Over the past five years (ie., 2021 to 2025), please identify the percentage of NS Power customers who have participated in E1's DSM programs. Please provide this information on an annual basis broken down by residential and business customers.**

ii) Pdf pg. 49 states: "Table 6 below offers insights on the rate impacts of the Preferred Plan as compared to no investment in DSM during 2027–2031. As can be observed from the table below, energy efficiency rate impacts are within the range of impacts seen in previous years (2011-2026), demand response generally has a downward effect on rates, and solar-PV has a minimal effect on rates."

- **Please explain how demand response has a downward effect on rates.**

iii) Pdf pg. 49 states: "E1's 2026 Historical RBIA indicates that ratepayers are already positioned to accrue aggregate bill savings in excess of $2.5 billion between 2011 and 2041 as a result of past DSM activities between 2011 and 2026."

- **Please provide the analysis to show how the $2.5 billion was calculated.**
- **Does the $2.5 billion represent the Net Present Value of the aggregate bill savings?**
  - **a) If not, what is Net Present Value of the aggregate bill savings?**
- **Does the $2.5 billion represent aggregate bill savings for only DSM participants or for all NS Power customers? Please explain.**

Response IR-17:

(a)

i) Please refer to EfficiencyOne's (E1) response to IG IR-12, Attachment 1.

ii) Please refer to E1's response to IG IR-12, Attachment 1.

iii)

	Actual			DSM Plan					
DSM Share of FTEs	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Program Delivery and Performance	40.9	38.2	32.1	39.4	35.7	35.1	35.1	35.1	35.1
Marketing and Customer Experiences	28.0	32.8	33.4	38.2	32.7	32.7	32.7	32.7	32.7
Regulatory Affairs	4.3	5.5	8.4	7.2	6.6	6.6	6.6	6.6	6.6
Engineering & Planning	11.7	9.9	9.2	6.9	9.5	9.4	9.4	9.4	9.4
Finance	5.6	6.7	6.0	6.6	6.8	6.8	6.8	6.8	6.8
Human Resources	3.4	2.8	3.1	2.8	3.3	3.3	3.3	3.3	3.3
Corporate Services	3.1	3.1	2.8	4.2	3.3	3.3	3.3	3.3	3.3
Information and Analytics	5.6	5.2	6.1	6.6	6.6	6.6	6.6	6.6	6.6
Information Systems and Technology	2.0	2.6	2.5	2.4	2.8	2.8	2.8	2.8	2.8
DSM Share of FTE	**104.6**	**106.8**	**103.6**	**114.3**	**107.3**	**106.6**	**106.6**	**106.6**	**106.6**

iv) Please refer to the table above for a breakdown of FTEs at the end of each year by department comparing the 2023, 2024 and 2025 actuals to the 2026 DSM Extension and the 2027–2031 DSM Plan. For each DSM Plan, the number of FTEs is based on the assumption that all positions will be filled at the end of each year. The 2023, 2024

and 2025 FTE count is reflective of E1 not having all vacant positions filled at the end of each year where the recruitment process extended into the following year.

v) Please refer to E1's response to IG-IR 12 part (a).

vi) Please refer to E1's response to part iii) for E1's FTE complement for 2023, 2024, and 2025. E1's FTE complement increased by 2.0 FTEs from 2023 to 2024 to support Demand Response and Market Transformation initiatives.

In thousands of dollars

	2023	2024	2025
DSM Salary Costs	$ 8,167	$ 9,394	$ 9,891

DSM Salary Cost increased in 2024 by $1.2 million over 2023. Annual employee salary adjustments accounted for $0.4 million. Between December 31, 2022, and December 31, 2023, as contemplated in the DSM Plan, 17.0 FTEs were added to support the implementation of the 2023–2025 DSM Plan. As these FTEs were hired throughout 2023, only a portion of their annual salary was included in 2023 DSM Salary Costs. A full year's salary for those hires, plus the addition of the 2.0 new FTEs, comprises the remainder of the increase year over year. DSM Salary Costs increased by $0.5 million from 2024 to 2025, driven by annual employee salary adjustments and inflation.

In thousands of dollars

	2023	2024	2025
DSM Benefit Costs	$ 1,398	$ 1,728	$ 1,808

DSM Benefit Costs increases correspond to the statutory rates applicable (EI and CPP) and related salary costs for each year.

In thousands of dollars

	2023	2024	2025
DSM Training & Development Costs	$ 242	$ 264	$ 134

DSM's share of training and development costs increased in 2024 as there was an opportunity for specialized training for key staff members. Return of service agreements, where an individual must repay full or partial fees for voluntary termination, are in place for significant training expenditures.

vii) Please refer to E1's response to part iii) for E1's FTE complement for 2026, 2027, 2028, 2029, 2030 and 2031.

In thousands of dollars

	2026	2027	2028	2029	2030	2031
DSM Salary Costs	$ 9,809	$ 9,745	$ 10,124	$ 10,486	$ 10,908	$ 11,367

DSM Salary costs are projected to increase between 3.6% - 4.2% over the 2027–2031 Plan period related to anticipated performance increases and inflation.

In thousands of dollars

	2026	2027	2028	2029	2030	2031
DSM Benefit Costs	$ 1,759	$ 1,747	$ 1,815	$ 1,880	$ 1,955	$ 2,038

DSM Benefit costs are forecast to increase in alignment with DSM Salary costs.

In thousands of dollars

	2026	2027	2028	2029	2030	2031
DSM Training & Development Costs	$ 322	$ 199	$ 203	$ 207	$ 211	$ 215

DSM Training and development costs are forecast to increase by 2 percent related to inflation.

viii) Salary and benefit costs from the 2026 DSM Extension compared to 2027 have decreased by $76,000. Training and development costs have also decreased by $123,000. The average salary and benefits for the 2027–2031 DSM Plan have

increased due to year over year salary adjustments and benefit increases projected at 4 percent per year.

ix)

- E1 did not conduct a benchmarking study that compared E1's total forecasted staffing complement, salary burden, employee benefits burden, and staff training budgets to other DSM jurisdictions.
- E1 is providing Attachment 1, a report by MacLean and Company on HR trends in 2026 and Attachment 2 (provided as Board-only confidential), a report provided to E1 on Mercer's compensation review. Both reports informed the 2027–2031 DSM Plan.

x) Please refer to E1's response to IG IR-12.

(b)

i) Please refer to Attachment 3 – Portfolio Simple Payback of this IR response.

(c)

i)

- The benefits of $682.5 million in the Preferred Plan would be subject to the same level of risk as E1 not meeting its performance targets of energy savings, peak demand savings from energy efficiency, demand response available capacity, and solar-PV generation. The benefits are directly linked to these targets and calculated on a per kWh and a per MW basis.
- Please refer to part (c) (i) of this IR response.

(d)

i)

- The Table and Figures in this section use the following language to distinguish different types of customers:
    - Total Customers – reflects all NS Power customers
    - Participants – reflects customers who have participated in DSM.
    - Non-Participants – reflects customers who have not participated in DSM.

Rate impacts (shown in Table 6) are the same for Participants, Total Customers, and Non-Participants.

Bill impacts for Participants, Total Customers, and Non-Participants are shown individually in Figure 8.

a) N/A – results are presented for Total Customers, Participants, and Non-Participants (refer to Figure 8).

i.

- Over the study period (2027–2046), the average residential non-participant will experience a bill impact of $0.74/month.

b) N/A – results are presented for Total Customers, Participants, and Non-Participants (refer to Figure 8).

i.

ii.

- Please refer to part (d) i) ● ○ a) i) ○ of this IR response.

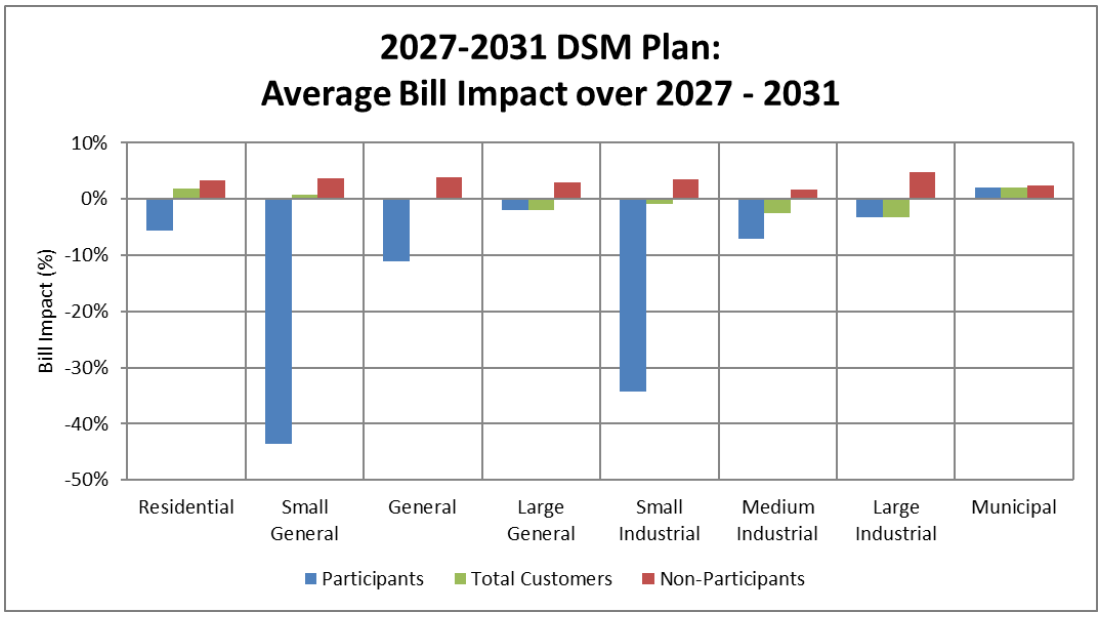
- Please refer to Table 1, below, of this IR response. The results are applicable to Participants, Non-Participants, and Total Customers (all NS Power customers).

Table 1: Preferred Plan – Average Rate Impacts by Resource over 2027 – 2031

	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal
DSM (All Resources)	3.69%	4.19%	3.92%	2.89%	3.47%	1.60%	4.70%	2.37%
Energy Efficiency	3.67%	4.29%	4.06%	3.11%	3.68%	2.14%	4.65%	2.51%
Demand Response	-0.04%	-0.11%	-0.15%	-0.20%	-0.20%	-0.49%	0.04%	-0.15%
Solar PV	0.06%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%

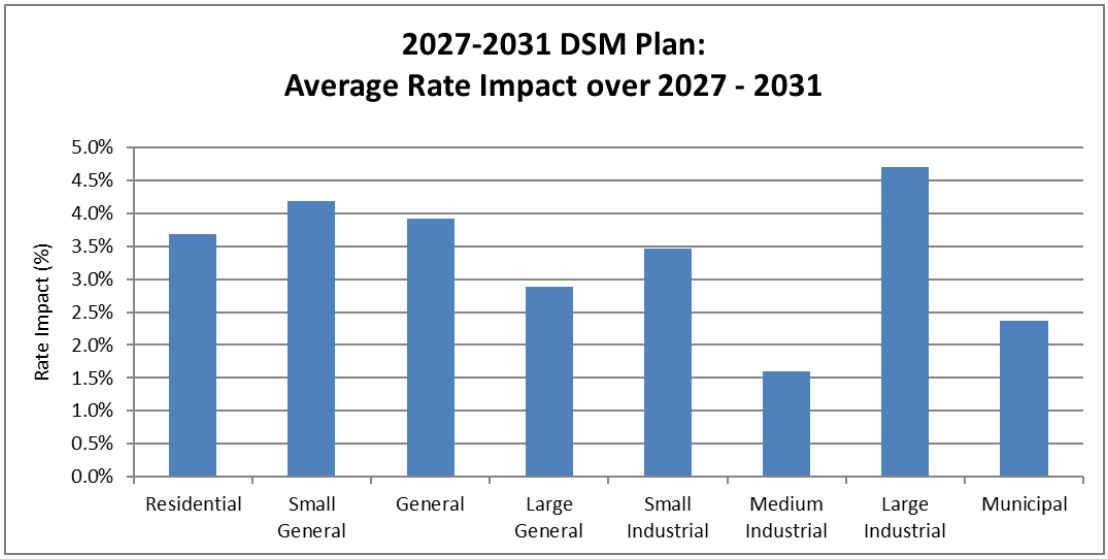
Please refer to Figure 1 of this IR response. The figure presents results for Participants, Non-Participants, and Total Customers and therefore addresses the request for a revised Figure 6 showing both Participants and Non-Participants.

Figure 1: Average Bill Impact (2027–2031) as a Result of DSM Activities in 2027–2031 (Preferred Plan)



- Please refer to Figure 1 of this IR response for a revised Figure 8 (showing customer bill impacts). Please refer to Figure 2 of this IR response for a revised Figure 7 (showing rate impacts).

Figure 2: Average Rate Impacts (2027 – 2031) as a Results of DSM Activities in 2027 – 2031 (Preferred Plan)



- Please refer to Table 2, below, of this IR response. E1 has included 2025 planned participation because actual participation was not available.

Table 2: Residential and BNI Annual Percent Participation (2021 – 2025)

Year	Residential Annual Participation	BNI Annual Participation
2021	25%	31%
2022	24%	32%
2023	24%	31%
2024	36%	33%
2025	34%	47%

ii)

- DSM activities reduce rates relative to a No DSM alternative when their downward impacts exceed any upward impacts. Downward impacts come from avoided costs, while upward impacts include program cost recovery and lost revenues.

Lost revenues are not applicable for demand response because it shifts electricity use rather than reducing overall consumption. Therefore, for demand response, lower rates result when avoided costs exceed program cost recovery. This is supported by the demand response PAC test result exceeding one, indicating that benefits (avoided costs) are greater than costs (program costs).

iii) In preparing the response to this IR, E1 identified that the $2.5 billion reported on PDF page 49 of E1's Evidence was an error and should state $3.2 billion, which is the value used in Appendix B. The following response is based on the corrected value of $3.2 billion.

- Refer to Appendix B – Attachment 9, tab 'Inter-class Outputs', cell AZ59.

  The following notes will assist with reviewing the calculation:

  Columns AY:BG represent the Base Scenario (No DSM)

  Columns BI:BP represent the Alternate Scenario (DSM). The model shows this as "Base Scenario", which is an error.

  The following selections must be made in the 'Inter-class Outputs' tab starting at cell C1 for the scenario to match the Historical RBIA (2011 – 2026 activities):

	Base Scenario	Alt. Scenario
Energy Efficiency	No	Yes
Demand Response	No	Yes
Solar	No	No
Placeholder	No	No
Electrification	No	No
Period	Historical Period (2011-2026)	Historical Period (2011-2026)
Cost Scenario	1	1

- Yes, the $3.2 billion corrected value represents the Net Present Value of the aggregate bill savings.

a) N/A

- The aggregate bill savings are for all NS Power customers.

McLEAN & COMPANY





HR TRENDS 2026

Leading Through Change:
Human-Centric and Future-Ready







Date Filed: May 28, 2026

REDACTED

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How to read this report

This report is based on data gathered from McLean & Company's HR Trends Survey 2026, which surveyed 1,626 respondents across various industries in August and September 2025.

Note: Graph totals may not add up to 100% due to rounding.

Key terms used throughout this report:

Organizational size:

Small: 250 or fewer employees
Medium: 251 to 1,000 employees
Large: 1,001 or more employees

High performing:

Respondents who selected five or six out of six when asked to rate performance across various parameters.

Highly effective:

Respondents who selected five or six out of six when asked to rate effectiveness across various parameters.

Highly proficient:

Respondents who selected five or six out of six when asked to rate their HR organization's proficiency across various skills or competencies.*

Highly effective at people leadership activities:

Composite measure of respondents who scored 54 or higher out of a maximum score of 72, averaging out to a score of 4.5 on each item each (scored on a six-point scale) when asked to rate the effectiveness of leaders at their organization across various people leadership activities.

See Appendix I for a breakdown of the characteristics of the respondents to the HR Trends Survey 2026.

See Appendix II for the HR FTE ratio and anticipated HR headcount change in 2026.

*Note: Some statements are based on the average response to multiple questions, where a threshold of 4.5 and above is deemed to be highly proficient.



TREND

No.1

HR in 2026: Leading Through Change

2026 marks HR's evolution from reactive support to proactive leadership. As organizations navigate relentless change, from AI and shifting employee expectations to economic uncertainty, HR's priorities are evolving fast. While leadership development remains the top focus, innovation has surged to second place from tenth, signaling HR's role in powering organizational agility and growth.

AI adoption is accelerating, embedding innovation into daily operations and putting focus on the HR–IT partnership. Together, they drive digital transformation and ensure technology delivers human-centric, high-impact results.

Yet, with rapid change comes change fatigue. Few HR teams excel at managing uncertainty. The solution: lead proactive scenario planning and partner with leaders to drive change, helping organizations anticipate disruption and build resilience.

In 2026, HR isn't following – it's leading the way. Read on to unlock your people's full potential and drive innovation at scale.

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Key terms in this section include:

Artificial Intelligence (AI)

A concept that focuses on increasing the intelligence of machines (computers) to complete tasks like learning, problem-solving, and understanding human language. In this section, AI is inclusive of generative AI, robotic process automation, and advanced analytics.

Info-Tech Research Group's AI Maturity Curve

This section will feature Info-Tech Research Group's AI Maturity Curve, which outlines AI adoption across five distinct phases:

Info-Tech Research Group, 2025

> See Appendix III for additional key terms used in this section.

Exploration (1)
No experience building or using AI applications.

Incorporation (2)
Employees at the organization have some skill in using AI applications or the organization is considering piloting AI.

Proliferation (3)
The organization has adopted and implemented AI applications in multiple departments. Some of the responsible AI guiding principles are addressed (e.g. data privacy).

Optimization (4)
The organization has automated the majority of its digital processes and leverages AI to optimize business operations. Controls are in place to monitor compliance with responsible AI guiding principles.

Transformation (5)
The organization has embedded AI into its culture and approach for building or implementing new business capabilities. Responsible AI guiding principles are operationalized with AI processes that proactively address possible breaches or risks associated with AI applications.

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Innovation gains traction while leadership development remains the top focus

Top HR priorities for organizations in 2025 (*n*=779)

01 Developing leaders
02 Retaining employees
03 Controlling labor costs
04 Providing a great employee experience
05 Recruiting

10 Enabling innovation

Top HR priorities for organizations in 2026 (*N*=1,626)

01 ■ Developing leaders
02 ▲ Enabling innovation
03 ▲ Providing a great employee experience
04 ▼ Retaining employees
05 ■ Recruiting
06 ▼ Controlling labor costs

▲ Moved Up ▼ Moved Down ■ No Change

See Appendix IV for the top 10 HR priorities from 2021 to 2026.

The rate of change in 2026 demands bold action from HR

HR must cultivate human-centric leaders, champion innovation, and transform the employee experience to steer the organization through constant change.

1

Developing leaders remains the top priority

The pace of change continues to accelerate year over year, resulting in evolving leadership expectations. Organizations need leaders who excel at the people side of leadership to navigate the constant flow of change and capitalize on new opportunities. When an organization has leaders who are highly effective at people leadership activities, they are 2.3x more likely to also report being high performing at innovation (*n*=1,297). Despite this, only 35% of HR organizations are high performing at developing the organization's leaders (*n*=1,600). In 2026, organizations that enable leaders to master change management and develop talent to foster innovation will have a significant competitive advantage.

2

Innovation surges in priority for HR

Rapid AI adoption is embedding innovation into daily operations and enabling continuous idea generation and new ways of working. As AI adoption accelerates, HR's partnership with IT becomes crucial, not just to keep AI implementation human-centric but to ensure AI is implemented to achieve the greatest return on investment and value across the organization. IT and HR are stronger together, and this collaboration is key to unlocking AI's full potential. Beyond IT partnership, HR must equip leaders with the skills and tools to drive innovation, lead change, and foster cross-functional collaboration.

3

Employee experience as a cost-control strategy

Organizations know that turnover is a bottom-line problem. As poor employee experiences drive turnover, organizations are investing in fostering positive experiences for employees as a cost-control strategy. When HR is high performing at providing a great employee experience, organizations are 1.8x more likely to report that they are high performing at cost optimization (*n*=1,514).

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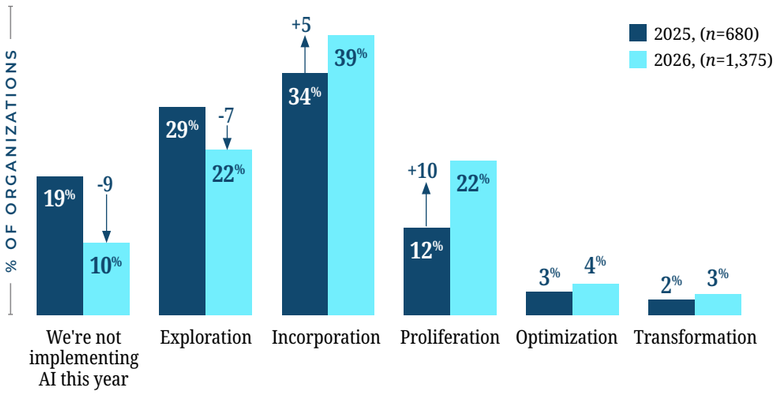
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Innovation is a top priority as AI advances, bringing HR–IT partnership to the forefront

Organizations are making strides in AI maturity, with more in the incorporation and proliferation stages.

This shift signals a reality where innovation and AI are finally becoming embedded in daily work.

Percentage of organizations by AI maturity level: 2025 vs. 2026;
changes indicated are percentage point changes



As more organizations advance in AI maturity, HR's role in driving change management efforts around digital transformation becomes more important than ever. Optimizing AI reshapes roles and workflows, making a human-centric approach essential for successful implementation.

However just...

37% of HR organizations are highly effective at enabling the adoption of new technology (*n*=1,579).

Enabling the adoption of technology is no longer optional. HR must accelerate their abilities in this space to keep up with the pace of change and position HR as a strategic differentiator, and the key to all of this lies in their partnership with IT.

CALL TO ACTION

Collaborate cross-functionally with IT.

Whether AI adoption is led by HR or IT, the mission is clear: drive organizational value through AI. HR and IT are stronger together, combining people and technical expertise. HR and IT collaboration is not optional; it is a catalyst for success in driving digital transformation and unlocking AI's full potential.

HR must step up to lead the organization through AI-driven change and innovation

Innovation and change are two sides of the same coin.

Introducing innovations, such as new products, services, or processes, drives change that can range from incremental improvements to sweeping transformation. The speed and scale of change will only intensify, with innovation now the #2 priority of HR.

The rapid accelerated pace of AI is pushing change management to its limits. AI is reshaping skills, structures, and workflows at an unprecedented pace. Yet, only 5% of custom AI projects reach full deployment (MIT, 2025). AI adoption is challenging, and without effective change management success becomes less likely. HR's role needs to expand from supporting change to leading it, guiding people and processes to adapt and grow alongside technological progress.

When HR is highly effective at managing change, respondents are...

2.3X **more likely** to report high organizational performance in innovation (*n*=1,422).

38% **less likely** to agree that "Change fatigue is negatively impacting my ability to be effective in my job" (*n*=1,406).

The importance of effective change management during rapid transformation is clear. However, only...

41% of HR organizations are highly effective at managing through change and uncertainty (*n*=1,446).

It's no surprise that change is becoming increasingly complex. AI is amplifying existing difficulties by completely reshaping how organizations approach change. The real obstacle isn't a lack of frameworks but an outdated mindset that struggles to keep pace with the relentless speed of change, largely driven by AI.

INSIGHT

The traditional linear approach where change is treated as a project with a clear beginning and end is now obsolete. In the age of AI, change is the only constant. Organizations must reconceptualize change by embedding change practices into their culture and ways of working to achieve their strategic priorities.

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"The leaders that are successful are the ones that see change as inevitable – it's constant – and they build resilience around it and make it part of their DNA."

Javier Feliciano,
Executive Vice President & Chief People Officer,
Meritage Homes

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Leaders are the key to overcoming change management challenges

70% of organizations report facing challenges managing change.
(*n*=1,391)

Top challenges impacting an organization's ability to manage change effectively:
(*n*=327)

01 Too many changes happening simultaneously

02 Lack of leadership accountability

03 Lack of leadership skills to manage change

CALL TO ACTION

Partner with leaders to drive change and overcome challenges.

Strategically prioritize changes: As the pace and volume of change accelerates, HR must partner with senior leaders to prioritize the most high-impact, high-value changes. This requires strategically assessing trends to identify opportunities and risks that demand immediate action while deprioritizing other initiatives to create space for those with the greatest impact.

Build leaders' change capabilities: HR must enlist leaders to co-own and implement changes. As the nature of change has evolved, HR must adapt its approach to equipping leaders with the tools and resources needed to manage change reactions, communicate change, and understand their role in sustaining long-term transformation.

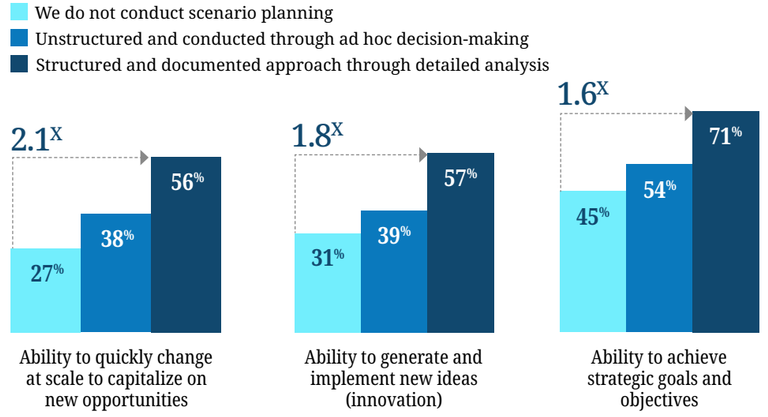
- When organizations embed leadership accountability for managing change in performance management practices, organizations are 1.5x more likely to also report being able to quickly change at scale to capitalize on new opportunities (*n*=1,322).

To lead change and seize innovation opportunities, HR must plan proactively

Scenario planning is more than a tool to uncover risks; it allows HR to capitalize on opportunities, prioritize changes, and build organizational readiness to navigate turbulent times.

Scenario planning enables organizations to drive strategic objectives through change:

Percentage of organizations achieving high performance in key organizational outcomes by scenario planning maturity level
(*n*=1,284 -1,313)



A structured approach to scenario planning provides organizations with a competitive edge by enabling them to anticipate disruption, unlock strategic opportunities, and lead effectively through change.

However, only

22% of organizations take a "structured and documented approach" to scenario planning.
(*n*=1,332)

CALL TO ACTION

Initiate scenario planning now.

While scenario planning may seem like wasting effort on unlikely scenarios, **it is no longer optional for organizations.** Dedicating time to it helps HR and the organization prepare for emerging opportunities and mitigate risks in an unpredictable environment. Organizations don't need to be perfect, and starting small builds familiarity and capability over time. When it comes to planning for future disruption, doing something is better than doing nothing at all.

See Appendix VI for an industry breakdown of scenario planning.

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What comes next?

Use McLean & Company resources to act on HR's top priorities in 2026 and lead through change and uncertainty.

Actions and practical resources

Align efforts with HR's top priorities in 2026 with McLean & Company resources on:

- Leadership development and leadership strategy
- Enabling innovation through culture
- Employee experience

To effectively work cross functionally to lead the organization through digital transformation, see:

- HR's Role in Driving Meaningful Digital Transformation
- Build a Strategic AI Roadmap
- Develop Responsible AI Guiding Principles
- The Future of Workplace Collaboration

For additional support on preparing for a strategic AI roadmap, see McLean & Company's Workshop Overview: Prepare HR for a Strategic AI Roadmap.

Elevate HR's technology enablement skills using McLean & Company's technology enablement training in the Learning Content Library. Focus on resources filtered by the "Digitally Aware" competency, such as Drive Results Through Technology Enablement Skills. Build leaders' AI skills with Facilitated Leadership Training: Generative AI Skills for Leaders.

To lead the organization through change and uncertainty, see the Change Management Resource Center and HR Guide to Scenario Planning.

TREND

Nº.2



Strengthening the Foundations of People Leadership

Leaders drive innovation and organizational change. As expectations for people managers rise, many are stretched thin, especially in the human side of leadership. It's no surprise that leadership development remains HR's top priority for 2026.

When leaders excel at developing talent and managing change, organizations are twice as likely to excel at innovation and agility. Yet most leaders fall short in these foundational areas, putting performance and productivity at risk.

To close the gap, HR must embed continuous learning into the culture, making development non-negotiable, supporting leaders with practical tools, and ensuring learning happens in the flow of work. Delegation and accountability are key: leaders should share responsibility and own their growth. When these elements align, organizations gain stronger leadership, greater adaptability, and sustained innovation.

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Key terms in this section include:

Highly effective at talent management:

Composite measure of respondents who scored an average of 4.5 or higher when asked to rate the effectiveness of leaders at their organization on the following activities (scored on a six-point scale):

- Conducting performance evaluations
- Providing feedback to employees
- Supporting employees in goal setting

Highly effective at talent development:

Composite measure of respondents who scored an average of 4.5 or higher when asked to rate the effectiveness of leaders at their organization on the following activities (scored on a six-point scale):

- Coaching employees
- Identifying learning opportunities for employees
- Supporting employees with their development goals

Highly effective at change management:

Composite measure of respondents who scored an average of 4.5 or higher when asked to rate the effectiveness of leaders at their organization on the following activities (scored on a six-point scale):

- Communicating the rationale behind decisions that impact employees
- Navigating difficult conversations
- Managing change reactions

Highly effective at employee engagement:

Composite measure of respondents who scored an average of 4.5 or higher when asked to rate the effectiveness of leaders at their organization on the following activities (scored on a six-point scale):

- Recognizing employee contributions
- Soliciting input from employees on team decisions
- Holding regular meetings to communicate progress toward team goals

> See Appendix VII for data on the percentage of respondents who rated their organization's leaders as highly effective at each people leadership activity.

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Innovation and agility are fueled by effective people leadership

Leaders who effectively manage change enable organizations to capitalize on opportunities, providing a competitive edge.

% of organizations that are high performing at changing quickly at scale to capitalize on new opportunities (*n*=1,309)



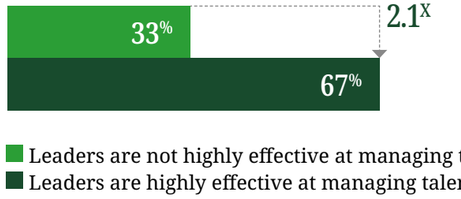
- Leaders are not highly effective at managing talent
- Leaders are highly effective at managing talent

By clearly communicating the rationale behind decisions, effectively navigating difficult conversations, and managing reactions to change, these leaders reduce friction during times of change.

When leaders are highly effective at managing change, respondents are **1.6x more likely to report that they are not experiencing change fatigue** (*n*=1,330). This reduction in fatigue lowers change resistance, enabling faster adoption and improving the ability to scale organizational changes effectively.

Leaders effective in talent development build the skills employees need to innovate.

% of organizations that are high performing at innovation (*n*=1,352)



- Leaders are not highly effective at managing talent
- Leaders are highly effective at managing talent

They achieve this by effectively coaching employees, uncovering learning opportunities, and supporting employees in achieving their development goals.

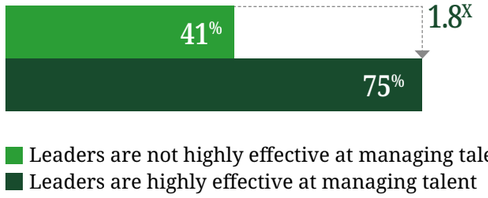
Exceling in these areas enables leaders to drive employee growth in alignment with current and future strategic objectives, including innovation. This builds in-demand skills, such as critical thinking and technology enablement, that push employees to challenge the status quo and adopt new ways of working.

> ***Organizations that develop leaders** to effectively manage change and build talent better position themselves to innovate and seize new opportunities in 2026 and beyond.*

Leaders are essential to a great employee experience and retention

Leaders who manage talent effectively provide clarity and purpose to employees' work, strengthening the employee experience.

% of HR organizations that are high performing at providing a great employee experience (*n*=1,359)



- Leaders are not highly effective at managing talent
- Leaders are highly effective at managing talent

When leaders provide effective feedback, support meaningful goal setting, and guide employee performance, employees gain the clarity needed to succeed. They understand what's expected in their role and see the connection between their work and broader organizational goals, driving a positive employee experience.

Leaders' effectiveness at engaging employees builds employee commitment to the organization.

% of HR organizations that are high performing at retaining employees (*n*=1,352)



- Leaders are not highly effective at employee engagement
- Leaders are highly effective at employee engagement

Leaders who are highly effective at employee engagement master the three components of McLean & Company's 3i's engagement model: inform, interact, and involve. Examples of how leaders demonstrate the 3i's in practice include:

- **Inform:** Holding regular meetings to communicate progress toward team goals.
- **Interact:** Recognizing employee contributions.
- **Involve:** Soliciting input from employees on team decisions.

Together, the 3i's strengthen employees' connection to their work and foster a sense of value, supporting long-term retention.

> ***To deliver on the third and fourth top priorities,** organizations must build strong leaders who excel at managing and engaging employees.*

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“When you invest in developing leaders, the impact is exponential. Leaders do a better job of developing, managing, and caring for their teams, lifting overall performance. But when you invest in developing employees without supporting leaders, that learning often fades because the environment doesn’t sustain it.”

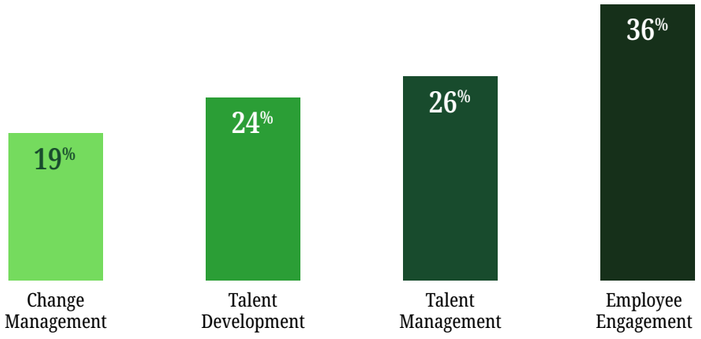
Miriam Ibrahim,
Associate Vice President,
Talent & HR Business Partnering,
Centennial College

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Stretched thin and overwhelmed, leaders are falling short in foundational people leadership areas

Leadership effectiveness is low across the four foundational people leadership areas that key organizational priorities depend on.

"How would you rate leaders' effectiveness on the following people management activities in your organization?" (*n*=1,359-1,369)



Excelling at the people side of leadership demands time to develop in and deliver on.

These four foundational people leadership areas include activities such as coaching, providing feedback, communicating decisions, and managing difficult conversations. These are complex, human-centric activities that require empathy, emotional intelligence, and trust. They are not quick and easy to master; they demand ongoing development.

Yet leaders are stretched thin and burned out, with limited capacity for the people side of leadership.

The role of the people leader has expanded, with heightened expectations across strategic, operational, and emotional responsibilities (Harvard Business Publishing). In 2025, people leaders were **1.4x** more likely than individual contributors to report they are **experiencing higher levels of stress related to their job today compared to one year ago** (*n*=1,378).

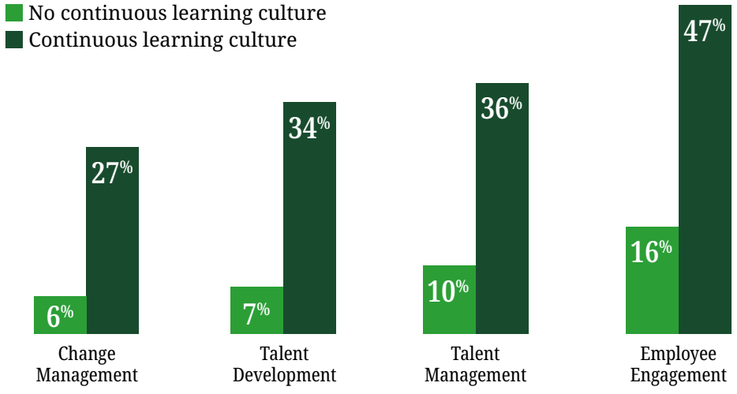
> When time is limited, it's easy for leaders to focus on what feels urgent: operational firefighting. The result? The people side of leadership is neglected. **Organizations must ensure that development in the people side of leadership is a top priority regardless of competing demands. It's not a nice-to-have, it's non-negotiable.**

Embedding learning into culture sets the expectation that leaders must prioritize development

A continuous learning culture is an organizational environment where learning is ongoing and encouraged at all levels of the organization.

When organizations have a continuous learning culture, leaders are more effective across four foundational people leadership areas.

Percentage of respondents reporting leaders at their organization are highly effective at: (*n*=1356-1366)



When development is positioned as optional, it consistently loses out to more urgent demands. A continuous learning culture sets a shared expectation that leadership development is a strategic priority.

While formal leadership development programs create a strong foundation for people leadership, they do not address capacity constraints. To bridge this gap, organizations must make learning easy to access, apply, and sustain within demanding workloads. This requires resources that embed learning into the flow of work, such as learning technologies, short-form content, and peer learning.

But even the most accessible learning will not gain traction without a clear, organization-wide expectation that development is a top priority. A culture of continuous learning reinforces that growth is an organizational imperative, not an afterthought, pushing leaders to prioritize their own development in service of broader success.

In 2026, organizations are relying on leaders to manage change and build, manage, and engage talent to deliver on top priorities. Yet leaders are failing to make time for development and are falling short in these four foundational areas. **Without a culture that prioritizes learning, the ability to deliver on key priorities is at risk.**

CALL TO ACTION

HR must partner with senior leaders to set the expectation that learning is an organizational priority.

While HR can help set this expectation through embedding a learning focus into organizational values or competencies, senior leaders must communicate the importance of learning and development to strategic success across the entire organization.

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Distributed leadership and accountability for development build a continuous learning culture

Distributing high-value leadership tasks supports a continuous learning culture.

It frees up leaders' time to focus on their own development while providing employees with meaningful opportunities to learn on the job. When leaders effectively delegate tasks within their teams, organizations are…

1.5X **more likely** to have a continuous learning culture (*n*=1,385).

Yet, just…

30% of respondents report that leaders in their organization effectively delegate tasks within their teams (*n*=1,388).

Leaders who are accountable for their own development set the tone for a continuous learning culture.

When leaders role model a commitment to professional growth, they establish learning and development as a norm and expectation, signaling that continuous learning is both a priority and a responsibility. When leaders are accountable for their own development, organizations are…

1.7X **more likely** to have a continuous learning culture (*n*=1,381).

However, only

38% of respondents report that leaders in their organization take accountability for their own professional development (*n*=1,384).

INSIGHT

Not all forms of delegation are developmental. When limited to low-value tasks, delegation is reduced to workload redistribution that undermines a continuous learning culture by crowding out time for meaningful, career-aligned development.

CALL TO ACTION

It's time to build a culture of learning systematically rather than hoping it happens organically.

It's not enough to declare learning as an organizational priority. It must be reinforced through talent structures like performance management, succession planning, and compensation. This drives an ecosystem where leaders are rewarded for owning their development and delegating effectively, strengthening a culture of continuous learning.

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What comes next?

Use McLean & Company resources to support leaders in foundational people leadership activities across all levels and deliver on HR's #1 priority.

Actions and practical resources

To explore how the role of the people leader is evolving and how to navigate it, see the Transforming the Role of the People Leader research.

To learn more about the 3i's of engagement, see the Enable Senior Leaders to Drive Employee Engagement research.

Explore McLean & Company's Management Fundamentals, Essentials for Leaders of Leaders and Leadership Development Coaching to lay the foundation for people leader effectiveness in managing change and developing, managing, and engaging talent.

Make learning easy to access, apply, and sustain using the:

- Reimagine Learning research
- Learning Content Library for competency-based learning

To identify strengths and development areas for people leaders, use McLean & Company's 360 Feedback diagnostic. Assess the application and impact of learning programs using the Learning Effectiveness Survey.

Set the expectation that learning is an organizational priority by embedding it into organizational values or competencies using McLean & Company's Articulate Organizational Culture and Develop Core and Leadership Competencies research. Reinforce this expectation through talent structures using the Develop a Talent Management Framework.

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TREND

Nº3

Harnessing Culture for Strategic Impact

When strategy shifts, culture must keep pace. The most successful organizations align their values with mission and strategy, especially during change. Values aren't just words on a wall; they're the compass guiding daily decisions. When values and strategy align, organizations are twice as likely to excel at innovation and adaptability.

But alignment isn't accidental. HR must ensure values are revisited, reinforced, and reflected in how leaders make decisions to build trust and resilience through change.

The missing link? Leadership accountability. Only half of organizations hold leaders accountable for living their values, but when they do, culture strengthens and outcomes improve. HR's role is to embed accountability into processes so that values aren't optional: they are simply how work gets done.

Bottom line: in a world of constant change, organizations that anchor strategy in lived values and leadership accountability build the trust, agility, and resilience to thrive.



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Key terms in this section include:

Organizational culture:

The dynamic system of shared beliefs and assumptions that guides behaviors and decision-making, manifested through symbols, **values**, and **behaviors** found in each interaction and experience.

- **Values** are the beliefs and guiding principles that set the moral compass of how the organization behaves and makes decisions in pursuit of the strategy, mission, and vision.
- The values are brought to life through the organization's **behaviors** and competencies, which support the achievement of strategic priorities.

Organizational strategy:

Identifies actions to deliver value and guide the organization toward the vision and mission.

Vision:

Description of an organization's aspirations and the wider impact it aims to build. It creates a cohesive understanding across all key individuals of the organization's existence and actions.

Mission:

Statement of the organization's core purpose, focus, and goals. It relies on the existence of the vision because it describes how the vision will be achieved.

Change fatigue:

A condition characterized by feelings of apathy and passive resignation toward organizational changes. It occurs when employees are worn out by constant changes and are in a perpetual state of uncertainty about the future.

Re-examining values amid strategic changes is key to cultural alignment

When was the last time your organization's culture and values were critically examined to ensure alignment with strategy? Is your culture helping execute strategy, or is it silently working against it?

When strategy, mission, and culture are fully aligned, organizations experience extraordinary results, achieving 316% greater revenue growth (Culture Partners and Stanford, 2023). Values are the catalyst for culture, enabling the right behaviors to bring the mission and vision to life. They not only reflect what the organization stands for, they must be used to actively shape decisions and guide actions toward strategic goals, especially during times of disruption and rapid change.

With nonstop shifts in the external environment, organizations are adapting their strategies at an accelerated pace.

For culture to drive strategy amid these changes, organizations must align their values with the right behaviors needed to achieve strategic objectives.

The alignment between strategic direction and the organization's values is crucial for achieving organizational outcomes.

When values are aligned with the organization's mission and vision, respondents were…

1.8X **more likely** to also report high organizational performance in the ability to quickly change at scale (*n*=1,264).

2.2X **more likely** to also report high organizational performance in innovation (*n*=1,299).

INSIGHT

Organizations must ensure their values still support their strategic direction. As strategy evolves in response to external disruption, values provide employees and leaders with clarity and confidence to act. While values should remain a steady foundation, they must also enable adaptability and innovation. The goal is not to change values with every strategic shift but rather confirm they continue to guide success. But if values are impeding strategy, it's time to make a change.

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Values reinforce culture during change, enabling organizational agility

A strong culture supports the ability to quickly capitalize on new opportunities through decisions grounded in shared values aligned with organizational strategy.

When HR is high performing at shaping organizational culture, respondents are:

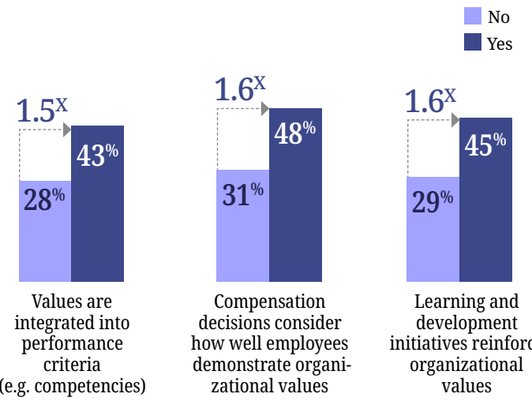
2.2X **more likely** to report their organization has a strong ability to quickly change at scale to capitalize on new opportunities (*n*=1,532).

Yet, only...

50% of respondents report their organization has a strong organizational culture (*n*=1,595).

HR programs must reinforce values to shape and sustain a strong organizational culture.

Percentage of organizations achieving high performance in the ability to change at scale to capitalize on new opportunities, based on whether these value-based practices are in place (*n*=1,198-1,243)



Values are integrated into performance criteria (e.g. competencies)

Compensation decisions consider how well employees demonstrate organizational values

Learning and development initiatives reinforce organizational values

CALL TO ACTION

Embed organizational values in HR programs.

Organizational values must be consistently reinforced through HR programs to shape and encourage behaviors that bring the culture to life and enable organizational strategy. HR must evaluate its programs to ensure continued alignment with values to support strategic priorities.

Aligning leadership decisions to values builds resilience and advances strategy

When change is constant, leaders often feel pressured to show quick results. Yet in that urgency to act, their decisions can stray from the organization's core values. Employees will notice this disconnect and begin to question the "why" behind decisions and resulting changes.

Just **53%** of respondents in the average organization **report they understand the rationale behind senior leader decision-making in their organization** (McLean & Company Engagement Survey Database, 2024; *n*=170 organizations, 149,660 respondents).

Only **56%** of respondents agree that leaders in their organization make decisions in alignment with organizational values (*n*=1,341).

That lack of understanding and alignment can grow into mistrust and breeds change fatigue.

Only **12%** of respondents report **not experiencing change fatigue** (*n*=1,468).

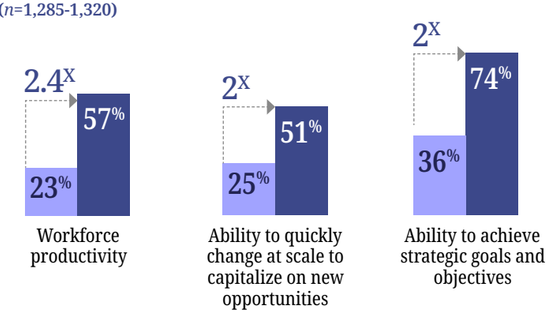
Anchoring decisions in values provides clarity, trust, and direction, ultimately fueling change resilience.

When leaders make decisions in alignment with organizational values, respondents are...

42% less likely to agree with the statement "Change fatigue is negatively impacting my ability to be effective in my job" (*n*=1,307).

This alignment results in tangible and meaningful impacts on organizational outcomes.

Percentage of organizations achieving high performance in key organizational outcomes when leaders make decisions in alignment with organizational values vs. when they do not (*n*=1,285-1,320)



Workforce productivity

Ability to quickly change at scale to capitalize on new opportunities

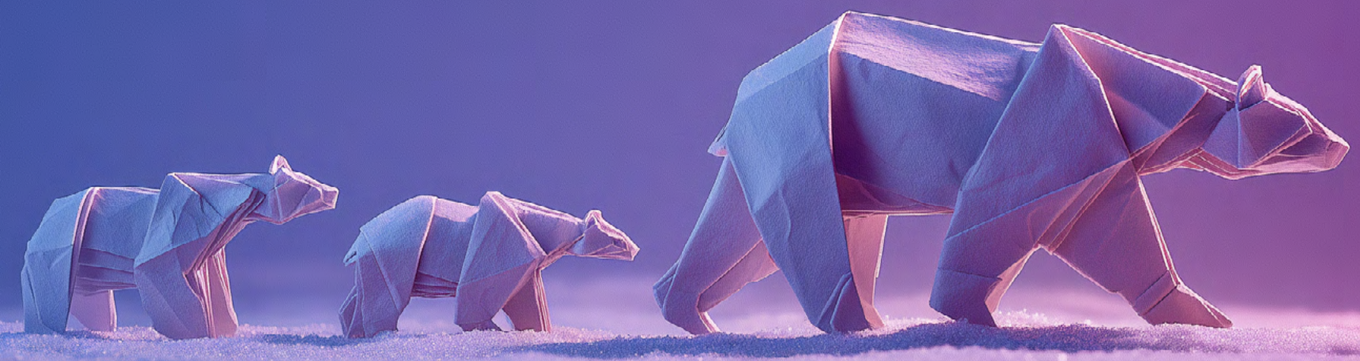
Ability to achieve strategic goals and objectives

Leaders in the organization don't make decisions in alignment with organizational values

Leaders in the organization make decisions in alignment with organizational values

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“If leaders continuously exemplify values amid all the organizational shifts, they give people certainty: ‘I can weather this change because I know my leader has my back.’”

Greg Shelton,
Associate Vice President People & Culture,
General Counsel,
AGC Biologics

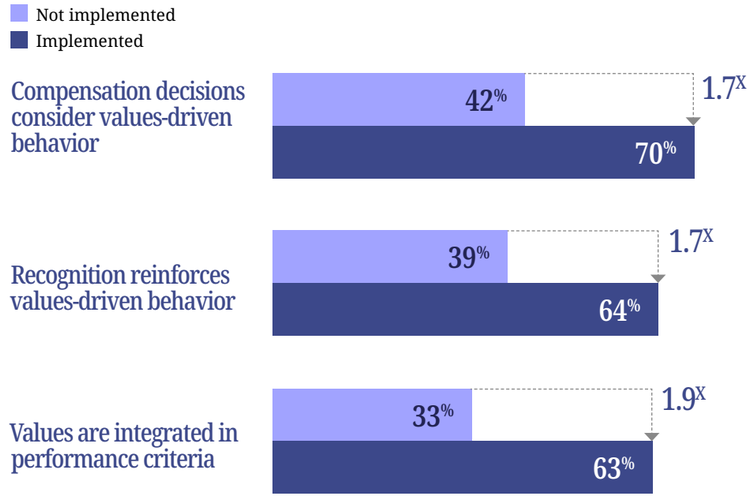
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Embedding leadership accountability in HR programs turns values into strategic impact

HR programs are a powerful tool to drive leadership accountability.

Percentage of respondents who agree leaders act in alignment with organizational values (*n*=1,242-1,294)



And when leaders are held accountable to organizational values, they are:

3.2X more likely to make decisions in alignment with those values (*n*=1,217).

CALL TO ACTION

Build leadership accountability to organizational values to drive strategic execution.

HR plays a critical role in hardwiring leadership accountability into systems and structures, creating ingrained practices so values stay front and center, particularly during times of change. If HR programs don't reinforce desired behaviors, efforts to build and sustain culture and drive strategy will lose traction and organizational outcomes will suffer. The mandate is clear: intentionally embed leadership accountability to act in alignment with organizational values into HR programs to set clear expectations and boost strategic impact.

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What comes next?

Use McLean & Company's resources to define organizational culture, strengthen employee resilience during change, embed core values across HR programs, and foster leadership accountability to drive values-based execution of organizational strategy.

Actions and practical resources

To articulate a culture in alignment with strategy, see McLean & Company's resources on culture: Shape and Sustain Organizational Culture and Articulate Organizational Culture. To further reinforce values across the organization, see Inspire Your Team Through the Organization's Mission, Vision, and Values and Identify Strategic Direction to Drive Aligned Action.

Watch McLean & Company's keynote on Leading in the Eye of the Storm: HR's Critical Role in Navigating Relentless Change.

To lead and navigate change, see the Change Management Resource Center. For training offerings, see:

- Facilitated Leadership Training: Lead Through Change
- Facilitated Leadership Training: Navigate the Change Management Process

Foster a resilient workforce during times of change by using McLean & Company's blueprint Develop a Resilient Workforce and learning resource Facilitated Leadership Training: Build Key Resilience Behaviors.

To build leadership accountability toward organizational values through HR programs and practices, see Redefine Performance Management and Ingrain and Sustain Employee Recognition.

To develop accountable behaviors, see McLean & Company's learning resources: Demonstrate Personal Accountability, Delegate and Build Accountability, and How to Prioritize Your Work When Everything Feels Important.

To further support employee engagement, see McLean & Company's Employee Engagement Program HR diagnostic.

TREND

Nº·4



Driving Success Through HR Collaboration

In 2026, HR's impact hinges on cross-functional collaboration. The data is clear: When HR partners effectively with key functions, its influence as a strategic partner grows, elevating HR from a support function to a driver of organizational outcomes.

Collaboration with IT is non-negotiable as AI adoption accelerates, ensuring technology is implemented with a human-centric approach that fuels innovation and prepares the workforce for change. Partnering with Finance helps HR optimize investments and measure ROI, while collaboration with Legal and Communications manages risk and delivers clear, consistent messaging during change. HR's most powerful tool for achieving this alignment and influence is the HR strategy.

The call to action: To expand its influence, HR must formalize its strategy and deepen cross-functional partnerships, leading the way in a rapidly changing landscape.

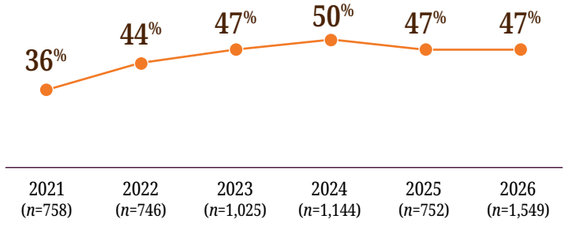
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HR's strategic influence is grounded in collaboration

Amid constant change and shifting priorities, HR's strategic influence within organizations has stalled.

Percentage of HR organizations reporting that HR is a partner in planning and executing strategy



Yet when HR is a partner in planning and executing strategy, organizations are…

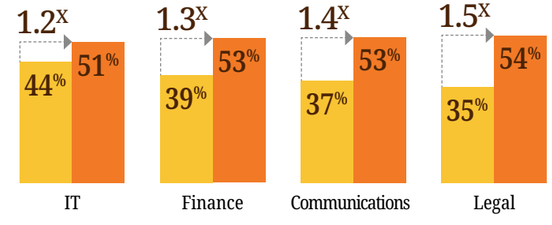
37% **more likely** to be high performing at achieving strategic goals and objectives (*n*=1,522; 48% vs. 66%).

In 2026, organizational success will depend on the strength of HR's strategic influence.

HR's partnership is critical to shaping and executing organizational strategy by identifying the talent and capabilities needed for success and mobilizing the workforce to deliver on objectives.

Effective collaboration with key partners across the organization elevates HR's influence.

Percentage of organizations reporting HR is a partner in planning and executing strategy based on HR's effectiveness at collaborating with the following functions (*n*=1,161-1,317)



CALL TO ACTION

HR must seize the opportunity to build influence through cross-functional collaboration.

As organizational priorities shift faster than ever, the only way to stay aligned is to improve HR's collaboration with key internal partners. Partnering with IT drives successful AI transformation and innovation. Collaboration with Finance ensures strategic resource allocation aligned to organizational priorities. Working closely with Legal ensures people practices are compliant and minimizes risk, while collaborating with Communications allows HR to lead change effectively.

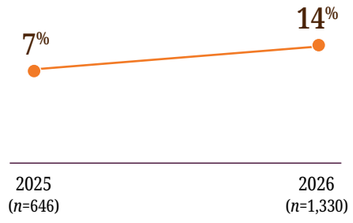
See Appendix VIII for a full breakdown of HR's involvement in organizational strategy and HR's effectiveness at collaborating with key functions.

HR and IT's partnership in the age of AI is a non-negotiable

AI adoption is accelerating, but most organizations are playing catch-up when it comes to having a formal AI strategy.

Sixty-eight percent of respondents report their organization is implementing AI beyond the exploration phase this year (*n*=1,375), but many organizations are putting execution ahead of strategic direction by implementing AI without a formal strategy. While the percentage of organizations with a formal AI strategy has almost doubled year over year, it remains disproportionately low compared to the number implementing AI.

% of organizations with a formal AI strategy



Implementing AI without a strategy risks failure by neglecting the human side of transformation.

An AI strategy ensures AI initiatives are aligned with organizational goals to drive value, proactively manage risk, and prepare the workforce to adapt and thrive in new ways of working.

By collaborating with IT, HR influences the organization to take a strategic, human-centric approach to AI transformation that unlocks AI's full potential.

When HR collaborates with IT effectively, organizations are…

2.0X more likely to have a formal AI strategy (*n*=1,156).

1.8X more likely to be high performing at innovation (*n*=1,356).

Yet, only…

55% of HR organizations are highly effective at collaborating with IT (*n*=1,372).

AI adoption is already underway, but only when HR and IT work together will organizations realize the value of AI.

Without HR's involvement, AI decisions risk overlooking the people impact, which has become a major barrier to successful adoption. Fear of job disruption, resistance to change, and lack of skills limit employees' ability to effectively work with new technology. HR is essential to overcoming these barriers through change management, targeted talent development, and proactive workforce planning. These efforts prepare the workforce to engage with AI confidently and apply it effectively, enabling organization-wide adoption and turning people readiness into a lasting competitive advantage.

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HR's business and data fluency strengthen collaboration with Finance to optimize investments

Effective HR–Finance collaboration equips organizations to optimize costs.

When HR and Finance collaborate effectively, organizations are…

1.4X more likely to be highly effective at cost optimization (*n*=1,312).

Measuring ROI enables HR and Finance to prioritize investments in programs that drive the greatest value.

As organizations navigate growing complexity and shifting priorities, effective resource allocation is critical to stay focused on what matters most. Measuring and articulating the ROI of HR programs enables HR, Finance, and other decision-makers to make informed, strategic choices about where to invest, pause, or redirect spending. This positions HR to better deliver on their top priorities by aligning resources to the programs that have the greatest impact.

When HR is highly effective at measuring the ROI of HR programs, organizations are…

1st Priority	**1.9X**	more likely to report that HR is high performing at **developing the organization's leaders** (*n*=1,199).
2nd Priority	**1.9X**	**more likely** to be high performing at innovation (*n*=1,197).

Yet, only…

29% of HR organizations are highly effective at measuring the ROI of HR programs (*n*=528).

CALL TO ACTION

HR must develop the skills to speak Finance's language to deliver on key priorities and optimize costs.

HR and Finance often speak different languages: HR focuses on long-term, human-centric outcomes, while Finance prioritizes measurable results. Breaking down these barriers starts with HR building the skills to collaborate effectively with Finance in service of driving the same organizational objectives forward.

To collaborate effectively, HR must strengthen their business acumen and data literacy skills to measure and articulate the impact of HR programs in financial terms. This enables strategic investment decisions that help HR deliver on their top priorities and support Finance in optimizing costs.

Risk management in an evolving landscape depends on HR–Legal partnership

In 2026, organizations will face various evolving and interconnected risks.

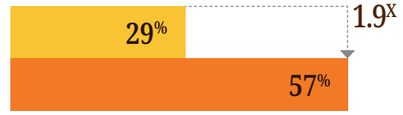
61% of executives anticipate a major increase in the level of risk they will be accountable for over the next three to five years (KPMG, 2024).

AI risks, regulatory shifts, and social and political dynamics are reshaping the risk landscape

The rapid adoption of AI in areas like recruitment and talent management introduces legal and ethical concerns, such as bias and privacy violations. The evolving regulatory environment increases risk of legal disputes and reputational harm. At the same time, social and political pressures require organizations to navigate complex issues carefully to maintain organizational trust both internally and externally.

Navigating these intersecting risks requires effective collaboration between HR and Legal.

% of HR organizations that are high performing at managing risks (*n*=1,200)



HR is not highly effective at collaboration with Legal
HR is highly effective at collaboration with Legal

Effective risk management doesn't just protect the organization, it creates the conditions for the organization to seize new opportunities.

When HR is high performing at managing risk, organizations are…

1.8X **more likely** to be high performing at quickly changing at scale to capitalize on new opportunities (*n*=1,526).

HR and Legal must partner together to manage risks and capitalize on new opportunities. Today's risk landscape is too fast-paced and high stakes for Legal to be treated as a final reviewer. When HR and Legal collaborate effectively, they don't just ensure programs, policies, and processes meet legal and ethical standards, they also anticipate and mitigate barriers early on, strengthening the organization's ability to respond confidently to change.

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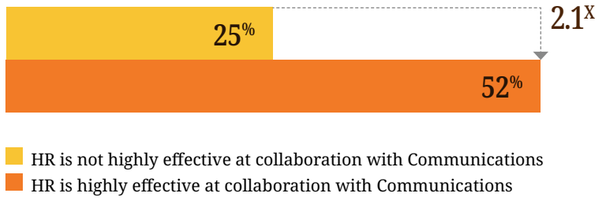


Partnership with Communications creates clarity through change

HR–Communications collaboration drives clear, consistent, and aligned messaging, reducing resistance during periods of change.

When HR and Communications partner effectively, they bring the storytelling, structure, and cadence needed to translate organizational changes into key messages employees can understand and act on. Together, HR and Communications can clearly articulate the rationale and "what's in it for me" behind the change across the organization. This helps ground employees in the change's purpose, reinforce strategic alignment, and provide a sense of clarity.

% of HR organizations that are high performing at navigating change and uncertainty (*n*=1,282)



INSIGHT

HR–Communications collaboration is essential to effectively manage change, regardless of how HR and communications functions are structured.

When HR and Communications operate as separate functions, HR must take an active role to build strong cross-functional partnerships to ensure communication efforts drive organization-wide alignment during change. When the functions are integrated, communications work must not be deprioritized or handled reactively. It is not optional; it is how HR will lead the organization through change.

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"There's no reason that different functions in an organization should be at odds or work in silos. It's not about one function needing something from another. It's about working together collaboratively with shared purpose and aligned metrics to move the organization forward."

Karen Smith,
Senior Vice President & Chief Human Resources Officer,
Bruce Power

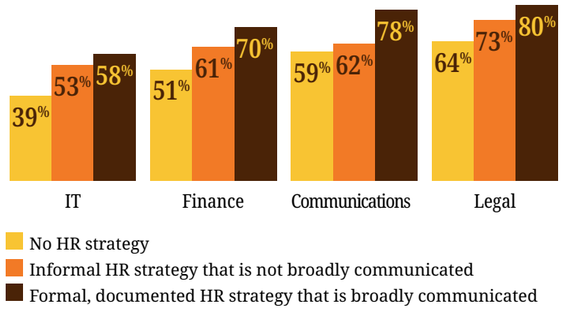
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A formal HR strategy strengthens cross-functional partnerships by linking HR's work to shared goals

A formal, broadly communicated HR strategy drives effective collaboration between HR and key partners:

Percentage of HR organizations reporting highly effective collaboration with key partners by HR strategy maturity level (*n*=1,059-1,224)



INSIGHT

An HR strategy is not just for HR. It is a strategic tool that helps key partners see how HR's work supports their priorities and contributes to organizational objectives, creating a foundation for stronger cross-functional collaboration.

Despite the clear benefits, many HR organizations still lack a formal HR strategy, limiting their ability to collaborate effectively across the organization.

Only **45%** of HR organizations have a formal, documented HR strategy (*n*=1,393).

However, collaboration is a two-way street.

HR needs to not only share their own strategy but also take the initiative to understand the priorities of other functions to build meaningful and effective partnerships. HR must also model the level of communication and collaboration they expect to see in return to set the tone for strong working relationships.

CALL TO ACTION

Transform disconnected work into coordinated, strategic partnerships with a formal HR strategy.

A formal, documented, and broadly communicated HR strategy signals to other functions how HR's work contributes to the overall organizational strategy. It gives HR a platform to proactively market its value, shifting perceptions from a support function to a strategic enabler. This improves alignment by clarifying HR's direction and making it easier for IT, Finance, Communications, and Legal to respond to HR's needs and work together to drive organizational objectives forward.



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What comes next?

Use McLean & Company resources to strengthen HR's collaboration with key partners in the organization.

Actions and practical resources

To learn about workplace collaboration, how it is changing, and how HR can partner with senior leaders to drive effective organization-wide collaboration, see McLean & Company's The Future of Workplace Collaboration Report.

To develop an AI strategy, see Build a Strategic AI Roadmap. To effectively partner with IT in driving AI transformation, see HR's Role in Driving Meaningful Digital Transformation.

To understand how to measure the ROI of HR programs, see the Guide to Measuring the ROI of HR Programs.

Strengthen HR's business acumen and financial literacy skills by exploring McLean & Company's Strategic HR Essentials and Elevate HR facilitated training programs.

To improve change adoption in partnership with Communications, see the Navigate Change research and Craft an Internal Communications Strategy blueprint.

Create a formal HR strategy to improve cross-functional collaboration using McLean & Company's Create an HR Strategy, and communicate HR's value to key partners using the Market the Value of HR research.

TREND

No.5



Preparing for Emerging HR Trends

Innovation is no longer optional; it's a strategic imperative. To stay competitive in an ever-changing market, organizations must distinguish meaningful shifts from background noise. Eleven emerging trends were examined to identify ones that will truly shape the HR landscape in 2026. Respondents assessed each trend's impact and indicated whether it's implemented, in progress, or planned within the next 12 to 18 months.

AI takes center stage as organizations seek to realize the promise of AI-enabled analytics and automation, but upskilling has yet to match that enthusiasm. Skills-based practices are becoming more common in hiring, bridging the gap between potential and reality.

Meanwhile, approaches like collective intelligence and learning in the flow of work are emerging as key ways to drive adaptability and growth.

When it comes to emerging trends, anticipated impact doesn't always match implementation rates

While practices like skills-based hiring and collective intelligence are becoming established drivers of innovation, AI-related initiatives, such as predictive analytics, AI-specific upskilling, and automation, show a significant gap between anticipated impact and implementation. Many organizations report having plans to adopt these practices, yet deliberate and proactive planning will be required to turn intent into reality.

Emerging HR Trends	Anticipated organizational impact (*n*=984-1,055)	Most Implemented (*n*=843-1,008)	Planning to Implement* (*n*=843-1,008)
^ v **Using AI for predictive analytics in HR**	**1**	**9**	**2**
^ ^ **Adopting skills-based hiring practices**	**2**	**1**	**1**
^ ^ **Enabling collective intelligence**	**3**	**2**	**4**
^ v **Implementing an AI-specific workforce upskilling strategy**	**4**	**10**	**7**
^ ^ **Learning in the flow of work**	**5**	**5**	**10**
Using AI to personalize the employee experience	6	8	6
Reimagining roles with more AI-driven automation	7	11	3
Implementing an internal talent marketplace	8	3	8
Enabling the workforce to adapt to a flatter organizational structure	9	4	9
Adopting agentic AI	10	7	5
Using nudgetech	11	6	11

^ v High anticipated organizational impact but low implementation rates
^ ^ High anticipated organizational impact and high implementation rates

*Note: Combination of currently implementing and planning to implement in the next 12 to 18 months.

#1 ANTICIPATED IMPACT

Upskilling will be crucial to turn excitement around AI-powered analytics into reality

Organizations are anticipating AI will improve their analytics capabilities through foundational work, such as using AI to clean and manage data, or complex analytics work, such as leveraging big data sets for predictive modeling and decision-making.

This enthusiasm has yet to be met with real progress, as despite 63% anticipating a high impact on their organization (*n*=1,054), only...

2% of respondents report they are using AI for predictive analytics in HR (*n*=955).

This low uptake reflects the reality of maturity in the use of analytics and AI across many organizations. Smaller organizations often lack the volume of data needed to support meaningful predictive analytics. What's more, many organizations of all sizes are still focused primarily on basic metrics and reporting. When it comes to AI in general, 61% of organizations are in the early adoption phase, exploring potential use cases and initiating pilot programs (*n*=1,375).

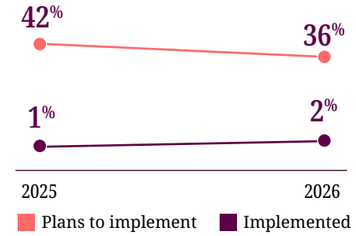
Nevertheless, momentum is building:

46% of respondents report they are either currently in the process of implementing using AI for predictive analytics or have plans to do so over the next 12 to 18 months (*n*=955).

Enthusiasm alone won't drive transformation. Elevating the analytics capability through AI hinges on upskilling the workforce.

While 54% of respondents indicated implementing an AI-specific upskilling strategy will have a high organizational impact (*n*=1,044), this has not translated into action.

% of respondents reporting they have implemented an AI-specific upskilling strategy or have plans to implement, 2025-2026 (*n*=468-911)



CALL TO ACTION

Upskill the workforce in AI to ensure enthusiasm translates into real value.

Despite high interest and excitement for AI in analytics, few organizations have taken real steps to upskill their workforce to make this a reality, and even fewer are planning to do so compared to last year. HR must lead the organization by influencing and enabling AI upskilling to unlock its full potential and maximize return on investment.

#2 ANTICIPATED IMPACT

Skills-based hiring practices remain the most implemented emerging trend year over year

Adopting skills-based hiring practices sustained momentum year over year.

20% of respondents report they have already implemented skills-based hiring practices, ranking as the most adopted trend for two consecutive years (*n*=527-990).

A further **49%** of respondents indicated they are currently implementing these practices or have plans to do so in the next 12-18 months (n=990).

If this continues, skills-based hiring is poised to become a standard practice across HR organizations.

Agility and necessity are two forces driving adoption, with smaller organizations leading the way in implementation:



Small organizations are 1.5x more likely than large organizations to report they have **adopted skills-based hiring** (*n*=964).



Large organizations are 2x more likely than small organizations to **have plans to implement this practice over the next 12 to 18 months** (*n*=964).

Smaller organizations have likely faced fewer structural and process-driven barriers in making the pivot to skills-based hiring. Larger organizations with more established processes and a greater number of decision-makers have been slower to implement but are catching up in 2026.

Implementation rates of skills-based hiring strategies are twice that of internal talent marketplaces (ITM) (*n*=990-1,008).

This gap highlights a critical reality: leveraging AI to match people to opportunities based on their skills, interests, and aspirations can be a complex process. Many organizations do not yet expect ITMs to deliver a strong return on investment, ranking eighth out of the 11 emerging trends in terms of anticipated impact.

The lack of momentum for a broader shift toward skills-based internal talent marketplaces is reinforced by low adoption rates with just…

35% of respondents reporting they are either currently implementing or have plans to implement an internal talent marketplace in the next 12 to 18 months (*n*=1,008).

CALL TO ACTION

Organizations cannot afford to rely on just one approach.

To meet the demands of a rapidly changing environment, agility is required in not only finding external talent but also deploying internal talent more intelligently across the organization. Combining skills-based hiring with an internal talent marketplace enables this by providing visibility into existing skills, identifying gaps, and supporting proactive workforce planning.

#3 ANTICIPATED IMPACT

Harnessing the collective intelligence of the organization is a powerful driver of innovation

Collective intelligence is shared knowledge that arises from the collaboration, collective efforts, and competition of individuals. This process is often enabled through technology to facilitate quicker knowledge sharing and innovation.

Organizations that report they have implemented enabling collective intelligence are…

1.5x **more likely** to report their organization is high performing at innovation (*n*=884).

As innovation surges as a top priority, it is no surprise that organizations see the value of investing in collective intelligence, with **58% of respondents anticipating it will have a high impact on their organizations** (*n*=1,054).

Enabling collective intelligence ranked as the second most implemented trend, and interest for future implementation is strong:

40% of respondents indicate they are either in the process of enabling collective intelligence or have plans to do so in the next 12 to 18 months, making it the fourth-ranked practice for future adoption (*n*=894).

As with AI, HR–IT collaboration will be crucial for implementation to match the level of anticipated impact.

Today's technology applications offer practical alternatives to real-time collaboration, whether in person or online. For example, AI integrations in platforms that house organizational knowledge and information, such as SharePoint or Google Workspace, allow employees to asynchronously tap into collective knowledge, expertise, and ideas more quickly, accelerating problem-solving and innovation.

While HR drives the knowledge-sharing practices that underpin collective intelligence, success depends on a strong partnership with IT to deliver the systems that make it possible. In fact, when HR is highly effective at collaborating with IT, the organization is…

24% **more likely** to report they have enabled collective intelligence (*n*=874).

INSIGHT

Organizations must accelerate the pace of innovation to match the pace of change. Harnessing collective intelligence is a key differentiator that enables teams to generate creative solutions, keep pace with new ways of working, and ultimately build a competitive edge for the future.

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#5 ANTICIPATED IMPACT

Learning in the flow of work offers a practical solution to deliver on leadership development

Learning in the flow of work refers to the seamless integration of learning activities into daily tasks and workflows, enabling employees to build knowledge and skills while performing their jobs. This can include accessing a short guide to learn a new task while doing it, which turns everyday work into development opportunities.

Organizations see the promise of learning in the flow of work, yet few have turned that promise into action.

53% of respondents anticipate implementing learning in the flow of work will have a high impact on their organizations (*n*=1,037).

However, only 8% of respondents have implemented learning in the flow of work, and only 31% are currently implementing or planning to implement it in the next 12-18 months, ranking it tenth among the eleven practices surveyed (*n*=843).

Although the concept has existed for years, advances in technology such as AI-enabled learning platforms have made learning in the flow of work more scalable and accessible, allowing organizations to deliver personalized, just-in-time learning content without pulling leaders away from work.

Organizations that fail to embed learning into the flow of leaders' daily work risk falling behind on top priorities.

Leaders are expected to manage change, engage, develop, and manage talent, and deliver on functional and operational tasks while staying on top of a rapidly evolving nature of work. As a result, leaders can only dedicate so much of their time to learning while still fulfilling their duties. Embedding development into daily work makes learning more accessible and sustainable, contributing to a culture of continuous learning.

This enables organizations to get leaders up to speed faster, reducing productivity disruptions and strengthening the ability to deliver on key priorities, including innovation and the employee experience. As the pace of change accelerates, organizations that outpace others in leadership development will be the ones that stay ahead.

#7 ANTICIPATED IMPACT

HR must plan for workforce impacts amid growing interest in reimagining roles with AI

Organizations are taking a "wait and see" approach to reimagining roles through AI-driven automation.

Only 1% of respondents indicate they have implemented this practice, ranking last among all practices surveyed (*n*=912).*

This reflects most organizations' position in the AI maturity curve. Nearly two in three organizations (61%) indicate they are in the early stages of AI adoption, focusing on exploring potential use cases and initiating pilot programs (*n*=1,375) rather than overhauling operating models and organizational structures due to AI.

However, interest in reimagining roles is strong:

41% of respondents report they have plans to reimagine roles through AI-driven automation, ranking third among all trends (*n*=912).

While it is too early to say AI-driven role automation will lead to widespread displacement of jobs, organizations' interest in this trend is a strong signal of future change.

AI-driven automation will impact tasks that are more repetitive and less complex. Entry-level roles fit this profile, making them the most likely candidate to experience significant disruption, including full replacement.

*See Appendix XI for a breakdown of AI-driven role automation implementation rates by industry.

If entry-level roles disappear, organizations risk creating a gap in the leadership pipeline. With leadership development already the top priority this year, HR must lead organizations through this AI-driven shift.

As entry-level roles decline, fewer organizational levels are needed, leading to flatter organizational structures. However, most organizations are currently unprepared for this structural change. Just 10% of respondents reported they have enabled organizations to adapt to a flatter organizational structure (*n*=887).

More concerningly, just…

33% of respondents report they have plans to enable their organizations to adapt to a flatter structure, ranking ninth among all trends (*n*=887).

INSIGHT

AI-driven change isn't just about technology; it's just as much about people. HR has a critical opportunity to lead, not by merely reacting but by proactively planning for these shifts. This means building a comprehensive leadership development strategy that equips employees at all levels with the ability to lead while proactively upskilling employees to take on broader roles and responsibilities. Ensuring a robust pipeline of future leaders equips the organization to thrive amid change and drive innovation.

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What comes next?

Use McLean & Company resources to learn more about the latest emerging trends that will continue to impact and shape the HR landscape in 2026 and beyond.

Actions and practical resources

To start using people analytics and explore its usage, see McLean & Company's Use Dashboards to Become a Data-Driven HR Function, Get Started With HR Analytics, Establish Data Governance for HR, and HR Technology & Analytics Certificate.

Cut through the noise and find clarity on what it means for your organization in What It Means to Become a Skills-Based Organization. Explore the opportunity to embed skills practices in your organization using the Leverage Skills Practices in HR Guide.

Prepare the organization to foster collective intelligence through collaboration using The Future of Workplace Collaboration and Equip Managers to Activate Networks to Enable Collaboration. Explore technology vendors that offer collaboration technology using SoftwareReviews' Content Collaboration Tools.

Reimagine learning in the flow of work with McLean & Company's human-centric, competency-based Learning Content Library, featuring microlearning and practical guides designed to help build real skills.

For additional learning resources, see McLean & Company's:

- A Leader's Role in Learning Reinforcement and Sustainment
- Reimagine Learning
- Feedback and Coaching Guide
- Leadership Competency Development Catalog
- Facilitated Training Programs

Reimagine roles and build a future-ready workforce using McLean & Company's HR Guide to Job Redesign, Address the Talent Gap Driven by Generative AI, and Upskill for the Future research. Prepare leaders for the future with Build Impactful Leadership Development Programs and its associated workshop.



Appendices

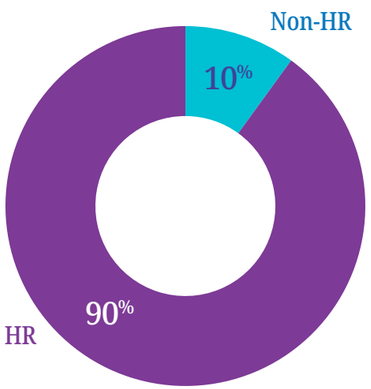
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Appendix I:

Characteristics of 2026 survey respondents

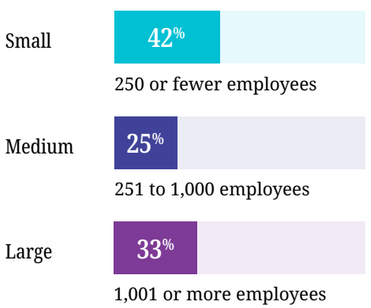
Role

(N=1,626)



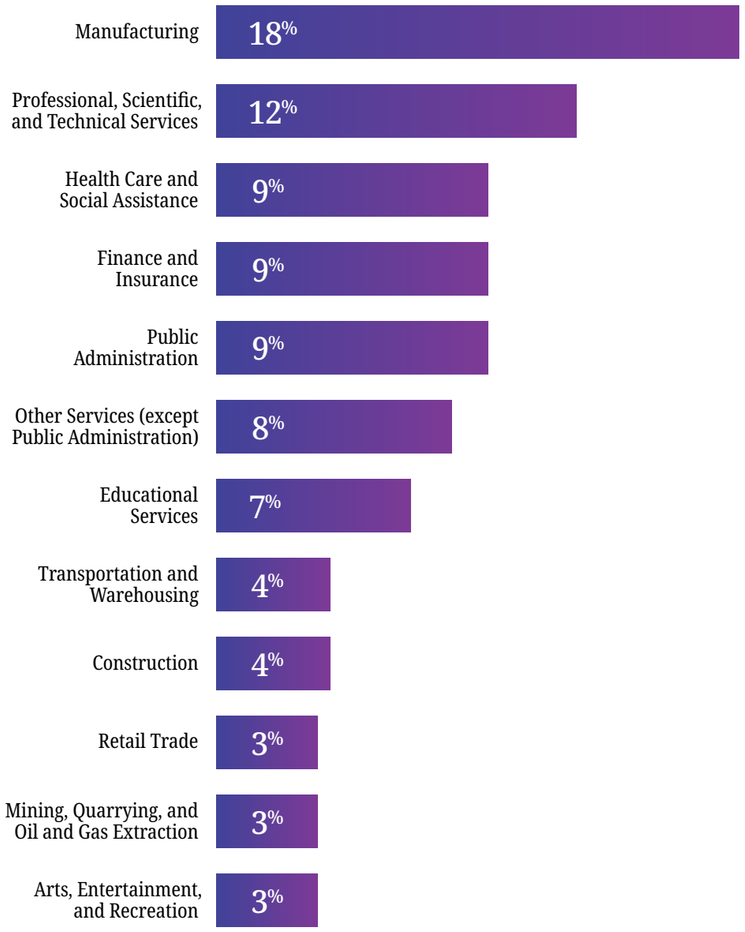
Organization Size

(*n*=1,547)



Respondents by industry

(N=1,625)



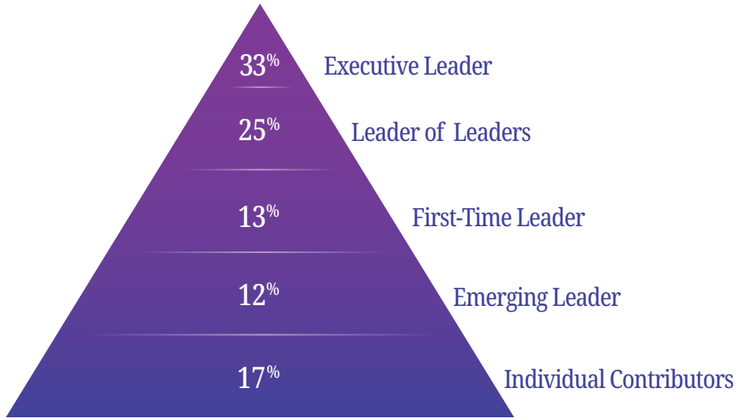
*Industries selected based on the North American Classification system. Categories falling below 3% were omitted from the visual above, reflecting 13% of the overall sample (*n*=214).

Appendix I (cont'd.):

Characteristics of 2026 survey respondents

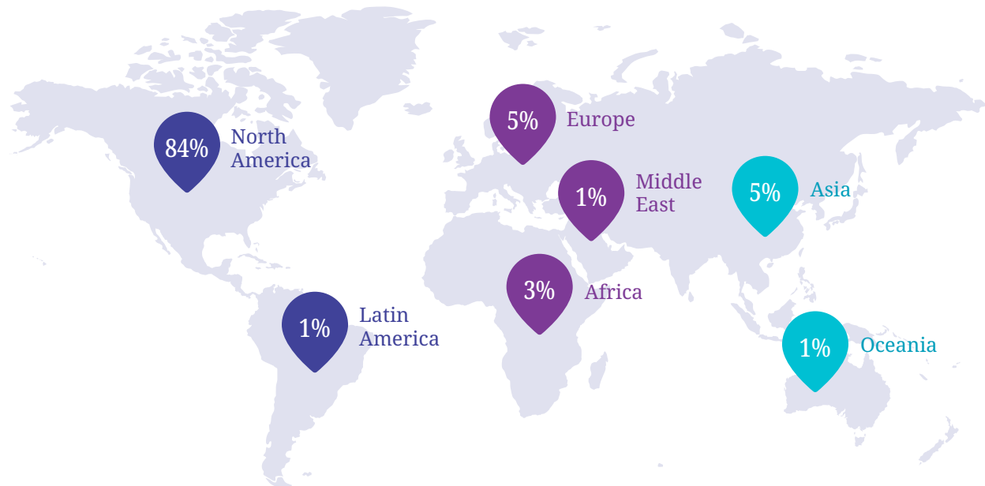
Seniority

(*n*=1,553)



Location of the organization's headquarters

(*n*=1,615)

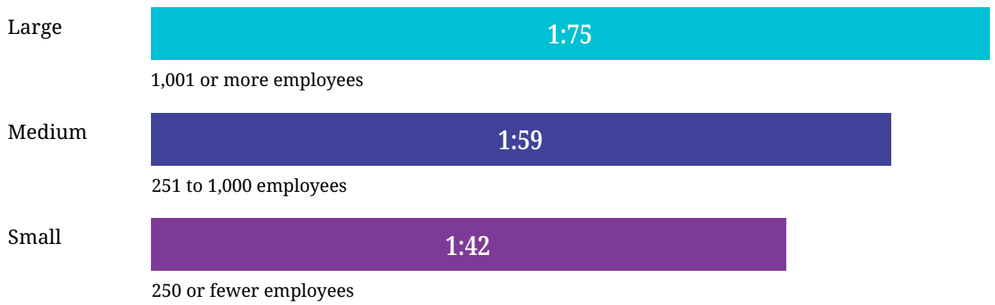


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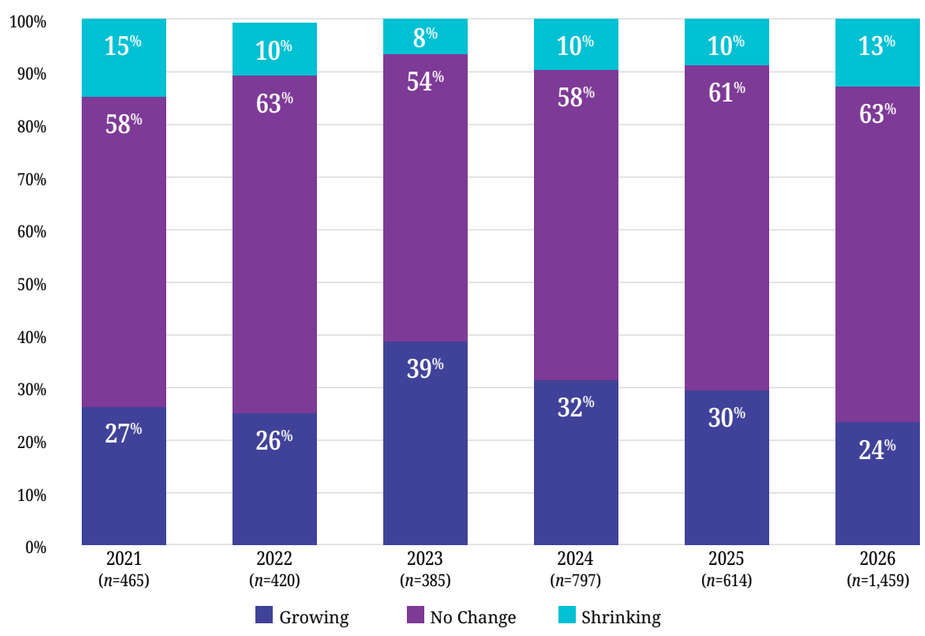
Appendix II:

HR:FTE ratio and anticipated HR headcount change

Median HR FTE ratio by organization size (N=1,319)



Anticipated change in HR headcount



Appendix III:

Key terms in HR in 2026

Change fatigue:

A condition characterized by feelings of apathy and passive resignation toward organizational changes. It occurs when employees are worn out by constant changes and are in a perpetual state of uncertainty about the future.

Digital transformation:

"The integration of digital technology into all areas of a business resulting in fundamental changes to how businesses operate and how they deliver value to customers" (The Enterprisers Project). Digital transformation is different than digitalization (moving from analog to digital ways of working and storage of data) because it requires new ways of working and process changes.

Human-centric practices:

Those practices that focus on the needs, experiences, and wellbeing of employees. They emphasize creating organizational value by creating workplaces where everyone can thrive and be fully engaged and productive. They are complementary to, rather than opposed to, organizational goals and financial outcomes, recognizing that investing in employee wellbeing and development ultimately drives innovation, efficiency, and long-term success.

Human-centric leadership:

The management of worker energy, wellbeing, engagement, and employee experience toward the achievement of organizational goals. It includes practices like feedback and performance management, coaching, recognition, and learning and development.

Scenario planning:

Strategic method used to create agile action plans by envisioning multiple plausible future scenarios to anticipate and capitalize on potential changes, uncertainties, and opportunities.

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Appendix IV:

Top 10 HR priorities for organizations in 2026 and 2025

Top HR priorities for organizations in 2026 (*n*=1,626)

01 Developing leaders

02 Enabling innovation

03 Providing a great employee experience

04 Retaining employees

05 Recruiting

06 Controlling labor costs

07 Navigating change and uncertainty*

08 Enabling learning & development

09 Facilitating data-driven people decisions

10 Fostering an environment of diversity, equity, and inclusion

Top HR priorities for organizations in 2025 (*n*=779)

01 Developing leaders

02 Retaining employees**

03 Controlling labor costs

04 Providing a great employee experience

05 Recruiting

06 Supporting change

07 Enabling learning & development

08 Facilitating data-driven people decisions

09 Fostering an environment of diversity, equity, and inclusion

10 Enabling innovation

*"Navigating change and uncertainty appears" only in the HR Trends 2026 Survey. It replaced "supporting change" from previous years.

**"Retaining employees" was added in the HR Trends 2025 Survey.

Appendix IV (cont'd.):

Top 10 HR priorities for organizations in 2024 and 2023

Top HR priorities for organizations in 2024 (*n*=1,193)

01 Recruiting

02 Providing a great employee experience

03 Controlling labor costs

04 Developing leaders

05 Supporting change

06 Enabling innovation

07 Fostering an environment of diversity, equity, and inclusion

08 Facilitating data-driven people decisions

09 Enabling learning & development

10 Rapidly moving internal employees to staff strategic priorities

Top HR priorities for organizations in 2023 (*n*=1,075)

01 Recruiting

02 Providing a great employee experience

03 Developing leaders

04 Controlling labor costs

05 Enabling learning & development

06 Fostering an environment of diversity, equity, and inclusion

07 Supporting change

08 Facilitating data-driven people decisions

09 Enabling innovation

10 Providing a great candidate experience

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Appendix IV (cont'd.):

Top 10 HR priorities for organizations in 2022 and 2021

Top HR priorities for organizations in 2022 (*n*=826)

01 Recruiting

02 Providing a great employee experience

03 Developing leaders

04 Controlling labor costs

05 Fostering an environment of diversity, equity, and inclusion

06 Enabling innovation

07 Enabling learning & development

08 Supporting change

09 Facilitating data-driven people decisions

10 Fostering a positive labor relations climate

Top HR priorities for organizations in 2021 (*n*=850)

01 Recruiting

02 Developing leaders

03 Controlling labor costs

04 Fostering an environment of diversity, equity, and inclusion

05 Providing a great employee experience

06 Fostering a positive labor relations climate

07 Supporting change

08 Enabling innovation

09 Enabling learning & development

10 Facilitating data-driven people decisions

Appendix V:

Top 10 HR priorities by industry

Top HR priorities for Manufacturing in 2026 (*n*=284)

01 Developing leaders

02 Providing a great employee experience

03 Enabling innovation

04 Recruiting

05 Controlling labor costs

06 Retaining employees

07 Enabling learning & development

08 Facilitating data-driven people decisions

09 Navigating change and uncertainty

10 Fostering an environment of diversity, equity, and inclusion

Top HR priorities for Professional, Scientific & Technical Services in 2026 (*n*=196)

01 Enabling innovation

02 Developing leaders

03 Providing a great employee experience

04 Enabling learning & development

05 Recruiting

06 Controlling labor costs

07 Navigating change and uncertainty

08 Retaining employees

09 Facilitating data-driven people decisions

10 Fostering an environment of diversity, equity, and inclusion

Top HR priorities for Health Care & Social Assistance in 2026 (*n*=148)

01 Recruiting

02 Retaining employees

03 Enabling innovation

04 Providing a great employee experience

05 Controlling labor costs

06 Developing leaders

07 Navigating change and uncertainty

08 Fostering an environment of diversity, equity, and inclusion

09 Enabling learning & development

10 Shaping organizational culture

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Appendix V (cont'd.):

Top 10 HR priorities by industry

Top HR priorities for Finance and Insurance in 2026 (*n*=146)

01 Retaining employees

02 Developing leaders

03 Controlling labor costs

04 Providing a great employee experience

05 Enabling innovation

06 Recruiting

07 Fostering an environment of diversity, equity, and inclusion

08 Enabling learning & development

09 Facilitating data-driven people decisions

10 Navigating change and uncertainty

Top HR priorities for Public Administration in 2026 (*n*=140)

01 Providing a great employee experience

02 Enabling innovation

03 Recruiting

04 Developing leaders

05 Retaining employees

06 Shaping organizational culture

07 Fostering an environment of diversity, equity, and inclusion

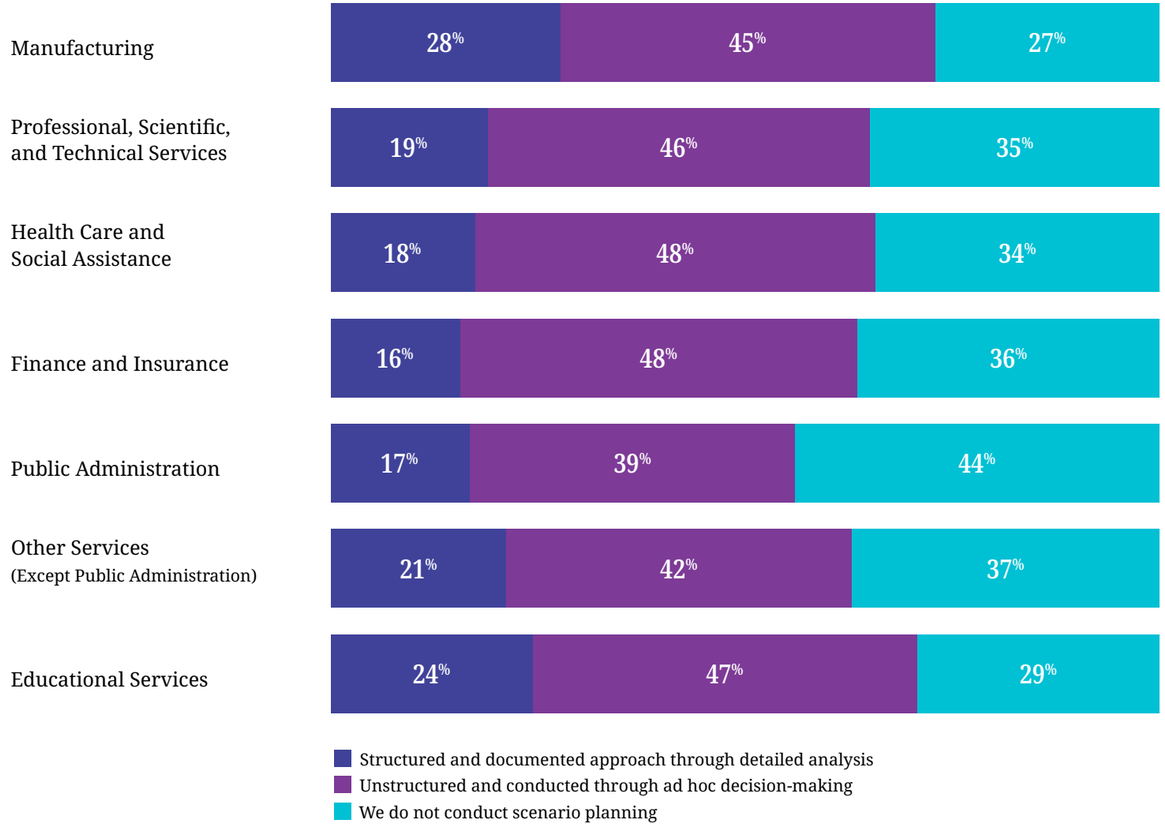
08 Controlling labor costs

09 Enabling learning & development

10 Navigating change and uncertainty

Appendix VI:

Scenario planning by industry (*n*=107-241)



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Appendix VII:

Leader effectiveness at people leadership activities

Talent management (*n*=1,375-1,379)

% of leaders highly effective at:



Talent development (*n*=1,378-1,384)

% of leaders highly effective at:



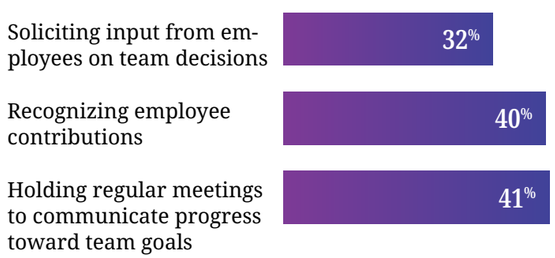
Change management (*n*=1,372-1,382)

% of leaders highly effective at:



Employee engagement (*n*=1,372-1,386)

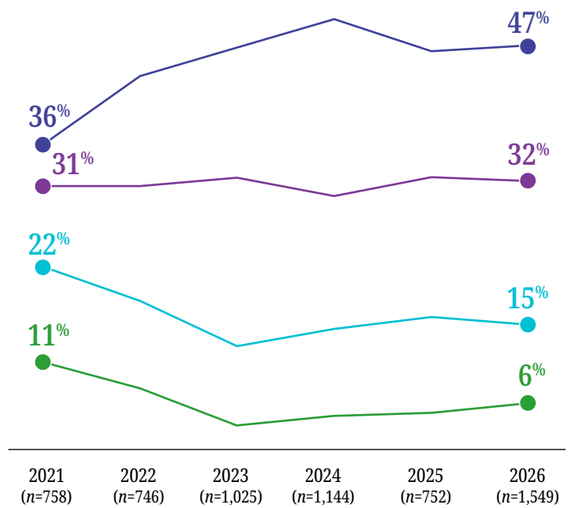
% of leaders highly effective at:



Appendix VIII:

HR's involvement in organizational strategy and collaboration effectiveness

HR's involvement with the broader organizational strategy year over year:



HR's effectiveness at collaborating with key partners:

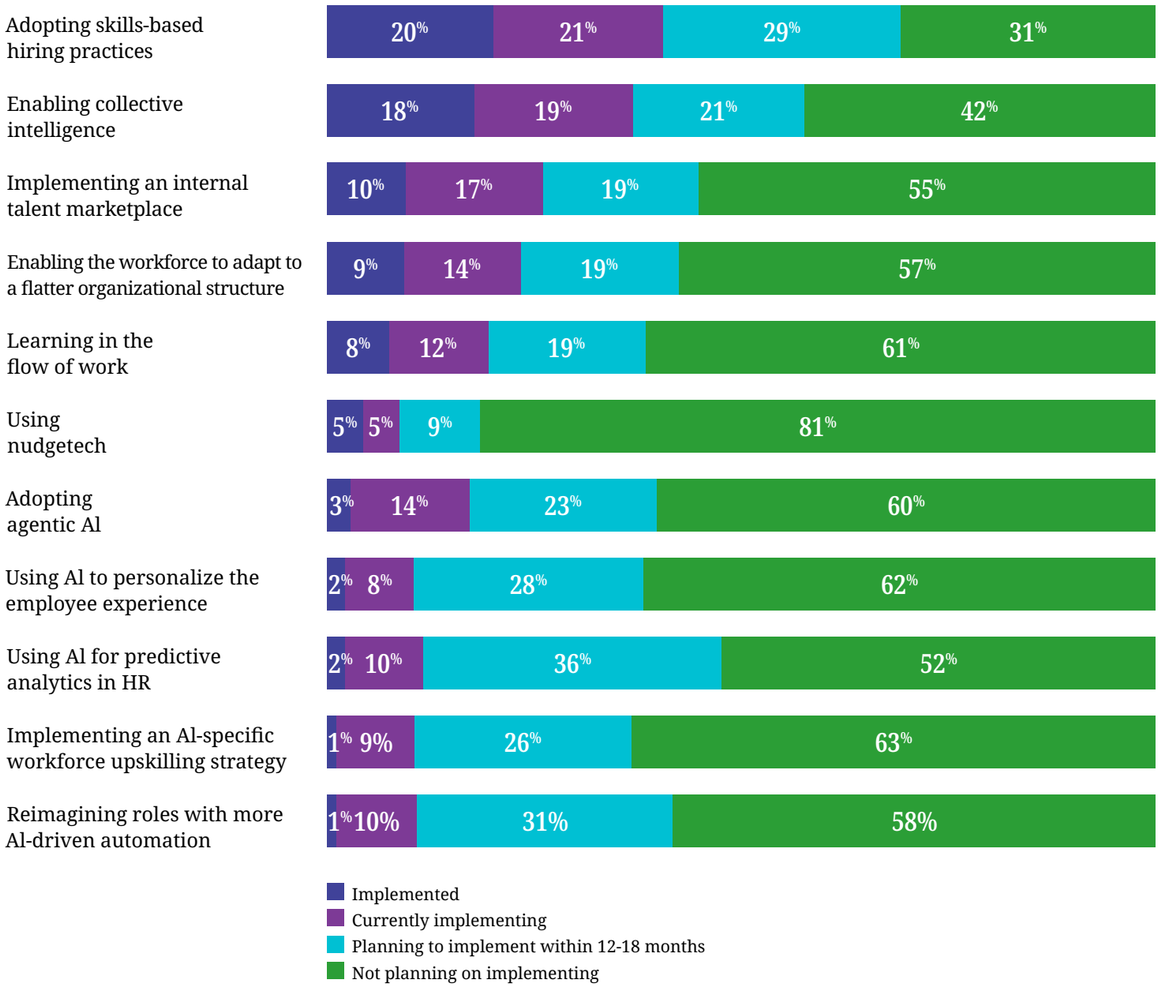
% of HR organizations reporting they are highly effective at collaborating with the following functions (*n*=1,203-1,387)

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Appendix IX:

Implementation rates of emerging HR trends

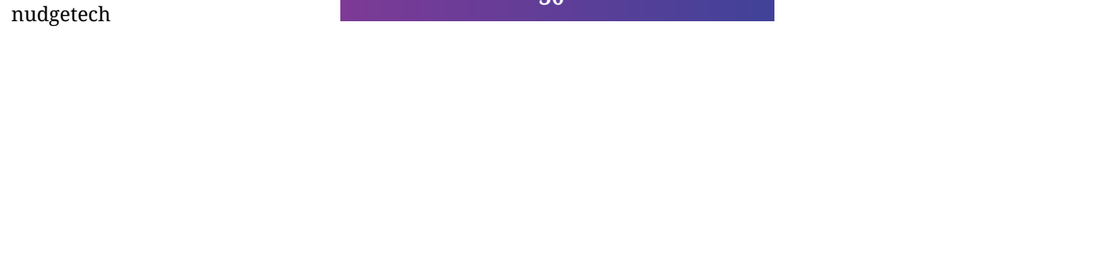
What is the current state of the following initiatives in your organization? (*n*=843-1,008)



Appendix X:

Rankings of anticipated organizational impact across emerging trends

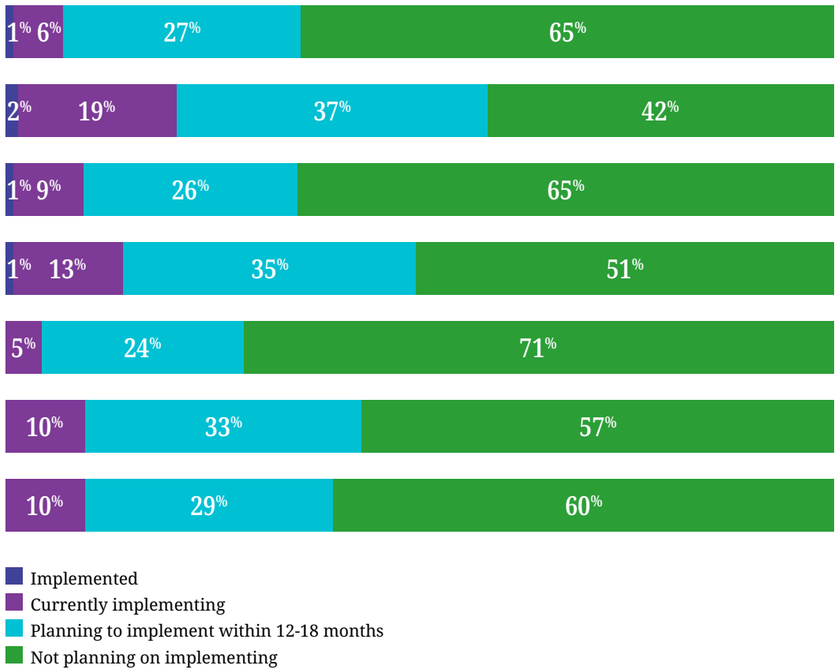
Organizations anticipating high organizational impact (*n*=984-1,055)



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Appendix XI:

Appendix XI: AI-driven role automation by industry (*n*=48-176)





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Research Contributors and Experts

Sanjay Singh,
CHRO, CMS Info Systems Ltd

Michele Campion,
CHRO, ESAB

Ryan Martin,
CPO, Healthcare Outcomes Performance Co. HOPCo

Karen Smith,
SVP & CHRO, Bruce Power

Greg Shelton,
EVP People & Culture, General Counsel, AGC Biologics

Javier Feliciano,
Executive Vice President & Chief People Officer, Meritage Homes

Teresa Coelho,
Global CP&SO, Accumin

Michael Kushner,
Chief People Officer, MetroPlusHealth

Kelly Murphy Almerico,
Assistant Vice President-Employee Experience at Ochsner Health

Miriam Ibrahim,
Associate Vice President, Talent & HR Business Partnering, Centennial College

Ato Taylor,
VP, Human Resources, Wacker Chemical Corporation USA

Missy Strong,
Senior Lead, People Experience, Pigment

Michel Boucher,
Vice President Human Resources, Royal Canadian Mint

Chris Collins,
Head of Human Resources, The Citco Group Limited

David Hawthorne,
Chief People Officer, Anchor Point Management Group

René Ramirez,
Chief Executive Officer, HomeFirst



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One Partner to Optimize the Impact of HR

Who is McLean & Company?

We are the fastest-growing research and advisory organization for HR executives and their teams. We deliver comprehensive HR solutions that enable clients to elevate the execution and delivery of HR strategies and key initiatives.

What differentiates McLean & Company from others in this space?

We meet you where you are. In addition to world-class research and expert partnership, membership includes:

- Topical and timely manager and employee training content that is compatible with most learning management systems.
- McLean Academy, an unrivaled online development program for HR team members.
- Flexible and comprehensive advisory services, including guided implementations.

… all at a highly competitive price point.

How do we deliver extraordinary value to clients?

Our value proposition is clear: we pair evidence-based research and immediately applicable tools with deep HR expertise. McLean & Company's scalable team solutions allow clients to accelerate attainment of goals and completion of key initiatives.

Who does McLean & Company serve?

We have clients across all industries, covering the spectrum of organizational size and complexity. Whether you are a multinational enterprise, a government entity, or a fast-growing startup, our solutions scale to meet your needs.

What is the impact of a McLean & Company partnership?

Our clients have greater influence at the executive level, deliver effective talent solutions faster, and produce more direct and positive impacts on business objectives.

"We made more progress with the Digital HR Strategy workshop in one week than we would have in three months. The information and materials were excellent, and the research was top notch and easy to understand. Our facilitators were very knowledgeable and engaging. They asked great probing questions and were able to pivot as needed. The workshop helped us to understand what we can accomplish when we work together. It was an overall excellent experience."

Senior Vice President,
Human Resources – Pharmaceuticals Manufacturing

"My Executive Counselor is a thoughtful listener, really understands the challenges my company is facing, and provides valuable insights and approaches, enabling me to best leverage McLean's resources and advance my company's talent agenda."

Vice President, People – Software

"My Executive Counselor is an extension of my HR team. He knows the team, he knows the barriers we're facing and he helps to address those concerns on a monthly basis."

Chief People Officer – Healthcare



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Request IR-18:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Reference to Exhibit E-1, page 44 of 71 (pdf pg. 51), Figure 6: Average Rate and Total Customer Bill Impacts as a Result of DSM Activities in 2027-2031 (Preferred Plan):

(a) Please explain why there are no total customer bill impacts showing in Figure 6 for the Municipal Rate Class.

Response IR-18:

(a) The total customer bill impact for the Municipal Rate Class is -0.04%. This value is not visible in Figure 6 because it is effectively zero.

Request IR-19:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 5 "The Balanced Plan Approach" of the Application:

(a) Regarding Section 5.2 "Program Delivery Costs":

i) Pdf pg. 53 states: "E1 has heard some concerns from stakeholders that program delivery costs have increased unreasonably since the last plan." Please provide a detailed summary of the feedback received from stakeholders related to increases in program delivery costs.

ii) Pdf pg. 54 states: "The 2024 DSM Evaluation results for residential heat pumps, established through a billing analysis, reduced savings for this measure by approximately 50 percent."

- **Please confirm that this lower savings result for this measure has been incorporated into the 2027-2031 DSM plan modeling.**
  - **a) If not confirmed, please explain.**

iii) Pdf pg. 54 states: "…incentive top ups for the Affordable Multifamily Housing program component are no longer provided by the Province. E1 has increased incentive levels to maintain participation following the end of this funding, directly increasing per-unit delivery costs attributable to the DSM Plan."

- **Please explain the rationale for E1's decision to increase incentive levels for the program following the discontinuation of government funding.**

iv) Pdf pg. 54 states: "…shifted the portfolio toward deeper, more complex measures such as building envelope upgrades, heat pump installations, and custom

commercial projects. These measures deliver greater long-term savings and higher lifetime value per dollar invested, but at a higher first-year unit cost."

- **Please explain whether the proposed higher first-year unit cost measures are expected to affect electricity rates, and how they align with DSMAG's recommendations on short-term benefits.**
- **Please explain how E1 balances between short-term and long-term benefits when planning projects.**

v) Reference to Exhibit E-1, page 48 of 71(pdf pg. 55),

- **"Benchmarking":**
  - **a) Please provide the market research and market comparisons prepared by independent third parties that were used by E1 to ensure that its costs during the Preferred Plan Period are aligned with other similar industries, organizations and DSM administrators.**
  - **b) Please provide the market conditions used to consider annual employee compensation changes and explain in detail how market conditions are used to set employee compensation levels.**
  - **c) Please describe E1's incentive program in detail and provide a copy of the review of the assumptions from the development of the methodology in 2017.**
- "**Independent Reviews"**
  - **a) Please provide a copy of E1's most recent third-party independent audits and reviews to ensure that its key controls are operating effectively and that the reporting of financial and savings results are accurate (not including the evaluation report filed as Exhibit E-3 in this proceeding).**

vi) Pdf pg. 55 states: "E1 has conducted third-party independent audits and reviews to ensure that the organization's key controls are operating effectively and that the reporting of financial and energy savings results are accurate." Please provide copies of these reviews and audits.

(b) Regarding Section 5.5 "Diversity of Program Delivery", pdf pg. 57 states: "Diversity in program delivery is a key way to minimize risk and involves the diversification of measures, markets and strategies. The Preferred Plan includes a full suite of programs and strategies that seek to address a broad range of opportunities across all residential, and BNI sectors. E1 has developed a diversified portfolio to account for risk from future world changes and to provide a broad program base to maximize equitable participation, which explains why certain of the included opportunities present a higher unit cost, or a lower benefit/cost ratio."

i) Please describe any changes in the diversity of the 2027-2031 DSM plan compared to E1's 2023-26 DSM plan.

Response IR-19:

(a)

i) Please refer to EfficiencyOne's (E1) response to NSEB IR-16.

ii) Confirmed.

iii) Please refer to E1's response to Synapse IR-38.

- Please refer to E1's response to part (a) iii).

iv)

- E1's first year unit cost is an output of E1's costs divided by E1's savings. Please refer to E1's response to IG IR-10, Attachment 2 for a first unit cost analysis. The costs or the numerator included in the unit cost calculation are

provided in E1's response to IG IR-12, Attachment 1. These costs inform the Program Cost Recovery (PCR) portion of NS Power's Demand Side Management Cost Recovery Rider (DCRR) by rate class. Please refer to part (c) of IG-IR- 09 for E1's estimated DCRR. E1 notes that for some rate classes the PCR may increase resulting in higher electricity costs, however, customers who participate in E1's programs will reduce their electricity consumption and ultimately realize electricity bill savings. Please refer to the Rate and Bill Impact Analysis provided as Appendix B in E1's application.

- In the DSM Plan, lighting measures, which were often a component of commercial projects, will not be supported by E1's business programs after 2028. Lighting measures provided high energy savings at a low cost. Commercial projects going forward such as retrofits or commercial equipment have higher upfront costs for customers and require more financial support from E1 through incentives, than lighting did. These projects provide customers with longer lifetime savings in electricity usage therefore resulting in higher overall benefits.

v)

- Benchmarking
    a) Please refer to E1's response to IG-10, Attachment 2, for the Apex memo on unit costs.
    b) Please refer E1's response to NSEB IR-17, Attachment 1 and Attachment 2, for the compensation reports. (NSEB IR-17, Attachment 2 is filed Board-only confidential).

c) E1 is providing the Board approved Incentive Setting Methodology that E1 follows as Attachment 1.[1] This matter was subject to a regulatory proceeding under Matter 07544 which was approved by the Board in July 2017. The methodology was subject to a third-party review. Please refer to E1' response to IG IR-11, Attachment 1.

- Independent Reviews
  a) Please refer to part iv) below.

vi) E1 is providing copies of the internal audits conducted since 2023 as Attachment 2, Attachment 3, Attachment 4, Attachment 5, Attachment 6. (Attachment 3 and Attachment 5 are provided as Board-only confidential).

(b) Please refer to Attachment 7 of this IR response for a comparison of diversification in 2023-2025 DSM Plan, 2026 DSM Extension and the 2027–2031 DSM Plan.

i) Please refer to part (b) of this IR response.

[1] M07544, Incentive Setting Methodology: CLEAResult Report & EfficiencyOne Implementation Plan, Second Revision, May 11, 2017. NSUARB Letter (70554), July 18, 2017: The NSUARB accepted "the Incentive Setting Methodology report and E1's Implementation Plan as filed on May 11, 2017."

CLEAResult

EfficiencyOne: Incentive Setting Methodology

May 11, 2017

PREPARED BY CLEAResult

PREPARED FOR EfficiencyOne

Disclaimer & Limitations

This final document was prepared by CLEAResult for the private and confidential information of the client for whom it was prepared and for the particular purpose previously advised in writing by the client to CLEAResult.

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Executive Summary

As a result of the regulatory process for the 2016-2018 Demand Side Management (DSM) Resource Plan, EfficiencyOne was asked to review its current incentive level setting methodology. The Nova Scotia Utility and Review Board (UARB) recognized that optimizing incentive structures and levels is difficult, but direction was provided to explore an approach that would assess whether incentive levels are being set at an appropriate minimum level while still resulting in program participation. The UARB requested that a quantitative analysis be considered in the methodology.

In response to the direction provided by the UARB, EfficiencyOne retained CLEAResult to investigate ratepayer-funded energy efficiency program incentive-setting methodologies from other jurisdictions, identify best practices and assess the implications of applying them to Efficiency Nova Scotia's portfolio of programs. The objective was to develop a comprehensive incentive-setting methodology approach.

Incentive setting is not an exact science. It has evolved through experience, and is often part of a broader program design framework. This report aims to distill the key components of incentive setting for EfficiencyOne's use.

The methodology provides incentive setting considerations for all of the programs in Efficiency Nova Scotia's (ENS) portfolio, as well as specific considerations for four specific energy efficiency programs. In developing the recommendations, CLEAResult considered Nova Scotia's market characteristics, the maturity of the programs in its portfolio, and other program design characteristics. The recommendations also included an incentive update protocol (as supported by flow charts, a documentation template and an Excel-based tool) that prescribes both frequency and methodology of updates. The scope of the project focused on financial incentives, though the other types of incentives were discussed.

The jurisdictional research involved primary and secondary research. The required background was developed by examining publically available reference material, as well as directly from program design, program evaluation or program management staff for each of the different jurisdictions to gain specific insight on the incentive setting process.

From reviewing the portfolio performance across the multiple jurisdictions studied, as well as comparing ENS's performance against Nova Scotia's Achievable Potential study[1], it is apparent that the ENS portfolio is performing at a level comparable to, or better than the other jurisdictions studied. The unit costs of conservation, along with the portfolio targets align favorably with the other jurisdictions.

One of the initial and most evident findings of the jurisdictional research is that there is minimal formalized and/or publically documented information on incentive design. Although many of the jurisdictions studied have applied best practices and documented approaches for program design, developed Technical Reference Manuals (TRMs) and performed market research, no consolidated document for incentive setting alone was found. However, through the interviews and research conducted, and by leveraging CLEAResult's experience across more than 900 active programs across North America, major themes and principles could be identified that were employed by all jurisdictions in their incentive level setting processes.

These principles include:

1. Assess and account for customer motivations and barriers to participation;
2. Determine technology savings, costs and market penetration;
3. Assess and account for supply chain and service provider considerations;
4. Determine financial impacts; and
5. Undertake jurisdictional benchmarking (for new incentives).

Against these general principles, EfficiencyOne's current incentive setting approach was reviewed and Nova Scotia's specific market characteristics were taken into consideration. The analysis covered both the general portfolio and four specific programs:

1. Instant Savings
2. Custom
3. Business Energy Rebates
4. Home Energy Assessment

It is important to note that our research indicates that EfficiencyOne conducts incentive setting according to these principles at a high-level. Supported by technology and market research and designed around financial parameters, EfficiencyOne's

[1] Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study – Navigant Consulting

approach is well aligned to other comparable jurisdictions. Activities performed to-date, such as the recent price sensitivity research in the Instant Savings Program and features such as the flexibility to negotiate incentives individually with customers for the Custom Program, support these principles, but there is room for improvement. Our recommendations provided later in this document focus on continuing the current activities, but improving specific areas. In an effort to further refine and develop the incentive setting methodology, CLEAResult identified the following areas for improvement:

1. Lack of a formal and documented incentive-setting process across all measures and programs;
2. The application of older market penetration analysis for important and rapidly changing measures;
3. Lack of a TRM or similar documents for all measure assumptions to be consolidated; and
4. Absence of readily available tools to perform short-term cost effectiveness calculations.

CLEAResult is providing the following recommendations for the identified areas of improvement:

1. Formally establish, document and use a consistent incentive setting process that incorporates the identified general principles.
    - Like most other jurisdictions, EfficiencyOne has not yet established a well-documented incentive level development process. EfficiencyOne would benefit as a peer leader by having a documented framework to ensure consistency in delivery and continuous refinement of the incentive setting process.

2. Conduct ongoing customer and technology research for identified technologies including residential and commercial LEDs, residential HVAC technology, commercial fluorescent technology and commercial Variable Frequency Drive (VFD) technology.
    - There are varying levels of rigour and different approaches to conducting this research depending on the jurisdiction reviewed. EfficiencyOne should conduct an assessment of their current research and identify if the required documentation requirements in the incentive level development process justify additional rigor. In some cases, existing research activities and data sources can be leveraged.

3. Ensure that the process used for determining energy savings and other measure assumptions provides the required information for incentive setting.
    - The energy savings and cost effectiveness metrics of the measures provide several reference points for setting the incentive level. EfficiencyOne should follow a TRM approach to support technology research, which will assist in gathering this information.

4. Develop a consolidated calculator/tool for short-term incentive setting and program design exercises, with the following functionality:
    - Capture and store measure-level information obtained from the recommended research activities and TRM process
    - Perform short-term program design or incentive-level cost effectiveness screening
    - Integrate the review protocol that has been provided in the Excel-based tool.

The consolidated calculator will allow EfficiencyOne to better conduct the analysis that supports incentive setting.

To support recommendation (1), CLEAResult developed an incentive setting process that uses these general principles that EfficiencyOne can use for incentive setting exercises. To complement the developed process, CLEAResult also created a documentation template that will ensure that the required analysis and documentation is considered for updating current incentive levels and for new incentives.

CLEAResult also developed an Excel-based tool that EfficiencyOne can use to identify specific incentive level setting considerations for different customer, program, technology and financial impact combinations. The model provides frequency recommendations for the incentive review process.

Finally, CLEAResult conducted a financial simulation for two programs:

1. Instant Savings
2. Custom

The purpose of this simulation was to evaluate EfficiencyOne's current incentive levels. To support this exercise, a financial analysis was conducted to evaluate the current incentive levels versus the three incentive level thresholds:

1. Cost to Customer
2. Program Budget
3. Cost Effectiveness

For Instant Savings, most of the incentive levels were within an appropriate range, but EfficiencyOne may wish to further investigate the current incentives for the heavy-duty timer and outdoor clotheslines in the Instant Savings program. The heavy-duty timer incentive level should be reviewed because the Cost to Customer analysis has reached the suggested upper limit. For outdoor clotheslines, the market penetration analysis indicates that the product may be standard practice in Nova Scotia homes.

For the Custom Program, EfficiencyOne should give careful consideration to project incentives for projects with energy savings persistence of less than seventeen years. This is to ensure projects stay within their Cost Effectiveness incentive threshold. The incentive needs to be justified by the value of the lifetime energy savings.

It is recommended that the financial simulation be conducted for all of EfficiencyOne's programs.

Overall, it is recommended that EfficiencyOne continue to conduct the required supporting research and develop the supporting tools and processes that provide a platform for the incentive setting process. It is also recommended that EfficiencyOne leverage the proposed incentive setting process and the documentation template, or a variation thereof that encompasses all of the recommended content and functionality. Ideally, all of the required analysis and related activities would be consolidated into one exercise that is followed consistently and at the required intervals.

If EfficiencyOne pursues these recommendations, the implemented incentive setting process will be a market leader in North America.

Project Scope and Background

The UARB directed EfficiencyOne to present these recommendations as a result of the regulatory process for the proposed 2016-2018 Demand Side Management (DSM) Resource Plan. In its August 12, 2015 Decision, the UARB directed a budget of $102.15 million for the 2016-2018 DSM Plan period[2]. This direction occurred after the proposed budget adjustment in the Quantum Agreement. The initial energy and demand savings targets remained unchanged.

	Budget ($)	Energy Savings Target (GWh)	Demand Savings Target (MW)
Initial Filing	$121.5 million	405.9	62.5
Quantum Agreement	$113.5 million	405.9	62.5
Final Order	$102.15 million	405.9	62.5

Table 1: EfficiencyOne Targets and Budgets

Between the Quantum Agreement and the Decision, there was a regulatory hearing to address a number of issues that the UARB had identified in its Final Issues List.[3]

During the hearing, EfficiencyOne argued that, "incentive levels are determined by various factors including comparison to other jurisdictions, market knowledge gained through historical program operation, market research and consumer pricing information."[4]

The UARB provided the following direction to EfficiencyOne regarding incentive setting, which was the catalyst for this research:

> "E1 is directed to undertake research and make recommendations on a more rigorous program for determining incentives…The Board recognizes that optimizing incentives is difficult; however a guiding principle should be that incentives are designed at the minimum levels required to induce participation and employ some quantitative analysis."[5]

Accordingly, EfficiencyOne secured the services of CLEAResult to undertake a study to identify incentive setting best practices and recommend changes to EfficiencyOne's incentive setting process.

[2] Decision 2015 NSUARB 204 M06733, Nova Scotia Utility and Review Board, August 12, 2015, Available: https://nsuarb.novascotia.ca/sites/default/files/M06733%20Board%20Decision.pdf

[3] M06733, In the Matter of An Application by EfficiencyOne for Approval of a Supply Agreement for Electricity Efficiency and Conservation Activities between EfficiencyOne ("E1") and Nova Scotia Power Inc.("NSPI"), the establishment of a final agreement between the parties, and approval of a 2016-2018 Demand Side Management ("DSM") Resource Plan, Final Issues List (16 April 2016).

[4] Decision 2015 NSUARB 204 M06733, Nova Scotia Utility and Review Board, August 12, 2015, Available: https://nsuarb.novascotia.ca/sites/default/files/M06733%20Board%20Decision.pdf

[5] Decision 2015 NSUARB 204 M06733, Nova Scotia Utility and Review Board, August 12, 2015, Available: https://nsuarb.novascotia.ca/sites/default/files/M06733%20Board%20Decision.pdf

Project Methodology

To produce recommendations for an incentive level setting methodology based on industry best practices, CLEAResult undertook the following steps:

Jurisdictional Scans

CLEAResult undertook jurisdictional scans of various provincial and state utilities and energy efficiency agencies to:

1) identify the incentive level setting methodologies and best practices in other jurisdictions; and
2) account for multiple possible approaches and methodologies that can be used when setting incentive levels.

The jurisdictions were chosen based on the following considerations:

- geographical similarity to Nova Scotia;
- portfolio maturity;
- recognized market leadership by American Council for an Energy-Efficient Economy (ACEEE);
- applicable incentive setting methodology; and
- energy efficiency program delivery mechanism (e.g., electric or natural gas utility vs. public agency vs. energy efficiency utility).

To complete the jurisdictional scans, CLEAResult used a combination of primary and secondary research. The secondary research was used to compile market characteristics and quantitative metrics for the selected jurisdictions (e.g., total energy efficiency program budgets and targets, etc.). The primary research was used to confirm the findings of the secondary research and to gain deeper insight into the specific incentive setting methodologies and other considerations and processes used by the jurisdictions, which may not be available in public documents.

The best practices were reviewed by the CLEAResult Subject Matter Expert (SME) team, which has significant experience in program design, delivery and evaluation.

The result of the jurisdictional scans, contained in Appendix A, are presented as comparative metrics which can be used to benchmark ENS's program incentives expenditure and total portfolio performance. The scans revealed multiple considerations and criteria that are used by other jurisdictions in setting incentives. As appropriate, these elements were integrated into the recommendations below.

Study of Nova Scotia's Market

To tailor the final findings to Nova Scotia's market, efforts were taken to understand the current landscape of energy efficiency programming, from both the perspective of EfficiencyOne and other major stakeholders in Nova Scotia. Secondary research was conducted to understand the electricity market in Nova Scotia. A review of Nova Scotia's current and forecasted electricity supply and demand was undertaken as well as a review of the population, building and load demographics. These factors are accounted for in our recommendations. Lastly, Nova Scotia's energy efficiency policies and the associated regulatory structure were also studied to fully understand how they currently drive incentive setting for ENS's programs.

Review of Efficiency Nova Scotia's Historical Performance

A review of ENS's historical program performance was undertaken to determine the success of the current programs in market. To obtain detailed information on select programs and their incentive setting methodologies, interviews were performed with selected program managers and staff. Lastly, program manuals and program evaluation reports were reviewed to gain insight into program operations, program maturity, success factors and recommended program modifications.

Analysis and Recommendations

The final analysis included a review of the theoretical underpinnings of incentive setting methodologies and established a framework, informed by jurisdictional best practices, on which CLEAResult's recommendations are based. This incentive setting framework is broadly presented and is applicable to setting incentives for any energy efficiency measure, program or portfolio.

A numerical analysis of financing where the quantification of the impact of financing on upfront monetary incentives was not included. Financing options are offered as an either/or alternative to upfront monetary incentives in the Green Heat Program, and financing is also offered to participants in the Custom program to cover the remainder of the project costs after the incentive has been netted out.

The current incentive setting methodology for four of ENS's programs (Instant Savings, Custom, Business Energy Rebates, and Home Energy Assessment) were then compared against our recommended incentive setting methodology to identify any existing gaps. Nova Scotia's unique market characteristics were accounted for in the recommended incentive setting methodologies.

To assist EfficiencyOne in setting new, or modifying existing incentive rates, an Excel-based tool was created to provide considerations that should be used in the incentive setting process.

Program Financial Simulation

To test the recommendations, a program financial simulation was conducted for both the Instant Savings and Custom programs. The current incentives were evaluated against multiple criteria, with a recommendation provided for the "appropriateness" of each incentive.

Incentive Setting for Energy Efficiency Programs

Energy conservation programs feature different types of incentives to attract participation. The underlying theory behind the design of energy conservation programs is that some energy efficient options are difficult to reach and are surrounded by barriers that need to be overcome in order for that option to become a feasible choice.

The three main types of barriers that most programs aim to address are cost, time and lack of knowledge.[6] The efficient option or choice is either too costly, is inconvenient, or the customer is not aware of it. Often, multiple barriers can be present. In order to address these barriers, programs use three main types of incentives:

1. Financial
2. Convenience
3. Educational/Technical Assistance

These incentives can be used in isolation, or in combination with each other, depending on the specific barriers present. All three types of incentives should aim to alleviate barriers to participation.

Often, the main component of utility or government sponsored energy conservation programs are financial incentives for residential and business customers to encourage them to make an energy-efficient choice. Financial incentives address the cost barrier. The jurisdictions investigated in this project feature financial incentives as a key component of their program strategy.

Depending on the program and jurisdiction, financial incentives were found to be as high as 75-80 percent of the total efficiency program portfolio expenditure. For example, National Grid has incentive expenditures in this range for their entire portfolio of electricity conservation programs. This level of magnitude indicates that financial incentives are a significant portion of any energy efficiency program or portfolio budget, which emphasizes their influence. Some jurisdictions, such as Massachusetts and Oregon, feature requirements that program administration costs be minimized as a portion of the total program delivery budget to ensure participants receive the majority of financial benefit from the programs via financial incentives.

Often, direct financial incentives to program participants are supported with convenience incentives. These types of incentives exist to address the time barrier; they are composed of mechanisms or structures that make participation easier. Convenience incentives are sometimes quantified financially as incentives, and at other times they have ancillary benefits that are captured under program administration costs. It should be noted that there is a cost associated with providing the convenience incentive, regardless of whether they are accounted for as financial incentives or fall under other program administration costs, and that these costs should be tracked. For example, appliance retirement programs often leverage convenience incentives by offering in-home pick up of old appliances. Small business and low income programs often feature direct install components, where a pre-qualified contractor performs the work for the customer. In general, all direct install programs are examples of convenience incentives, combined with financial incentives.

The costs associated with providing convenience in both appliance retirement and direct install programs are often quantified financially as incentives, versus program administration costs. These specific types of programs in the ENS portfolio account for these costs as financial incentives. In some cases, items that make customer participation easier are not considered convenience incentives since they are categorized as part of good customer service or optimal program delivery. For example, an online incentive submission system that is developed to maximize the user experience may make participation easier, but the development and operational costs are not considered incentives. This quantification is due to the online application system not directly being related to energy efficiency, and the value of the ancillary benefits to the program administrator, such as improved application review, reporting and incentive payment processes.

The final type of incentives that are common in energy conservation programs are educational and technical assistance incentives. These incentives address the lack of knowledge barrier. From posting energy savings tips and a home energy assessment tool on a public website to providing residential and commercial on-site energy assessments or large industrial energy management labor resources, educational and technical assistance incentives can cover the entire spectrum of customers. Depending on the type of activity, these incentives may be quantified as a financial incentive if they are tied to specific energy efficiency projects and are associated directly with energy savings. For the programs in the ENS portfolio, educational incentives are not quantified as financial incentives.

[6] Canadian Energy Efficiency Alliance, “CEEA 2014 Survey: Canadian Business Attitudes on Energy Efficiency,” http://energyefficiency.org/wp-content/uploads/2014/05/CEEA-Survey-2014-Final.pdf, (2014).

Incentives are critical to achieving program success by removing barriers to participation. The ultimate goal of energy conservation programs is to achieve market transformation, which is discussed in the section below. Market transformation ensures that the efficient behaviour becomes standard practice, and savings can be attributed to Codes and Standards rather than claimed through incentive programs. This is considered sustainable success, since the market then leads the way on making the energy-efficient choice. However, it can take multiple years for any given technology or behaviour to achieve market transformation, and there may always be new efficiency levels or best practices for that technology or behaviour.[7]

MARKET TRANSFORMATION

The ACEEE defines market transformation as the "strategic process of intervening in a market to create lasting change in market behaviour by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective energy efficiency as a matter of standard practice."[8] Standard practice refers to the state where incentives are no longer necessary; the energy efficient behaviour becomes the norm and the market naturally gravitates towards that option without the need for intervention. The market transformation process can be illustrated using the following technology adoption curve:

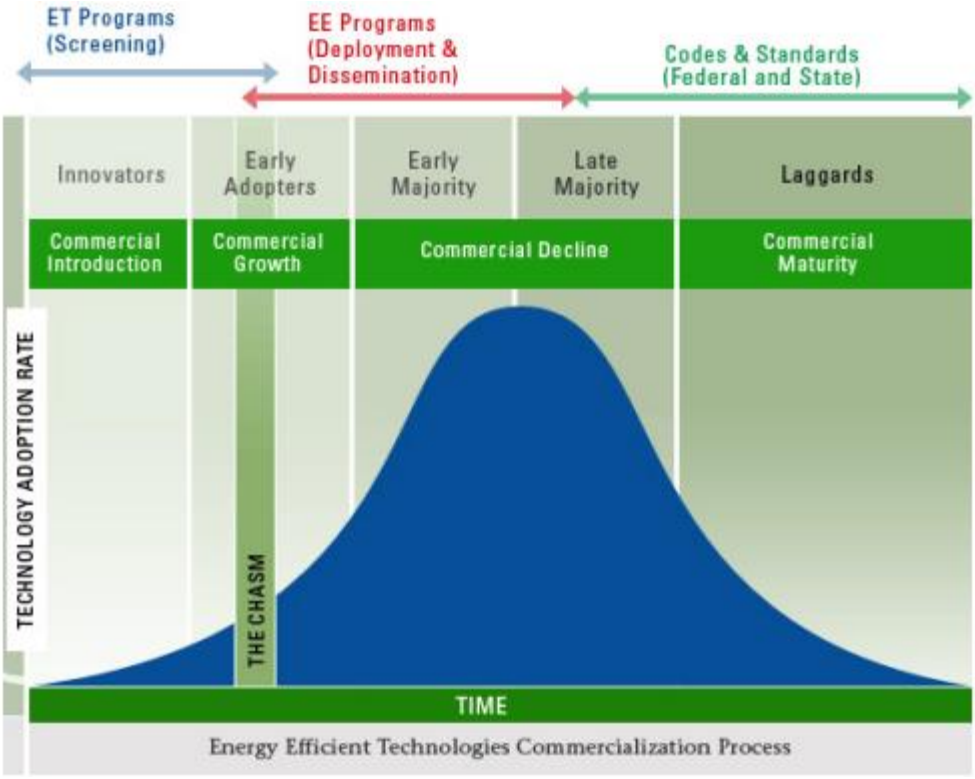


Figure 1: Technology Adoption Process [9]

For utility or government-sponsored energy efficiency programs, it is important to consider a technology's maturity when determining the best time to begin providing financial incentives to drive the market uptake of that technology. As identified in Figure 1 above, "The Chasm" is typically a time when a technology is sufficiently market ready yet requires financial assistance to begin market transformation at a large scale. Incentives are usually offered until the start of the late majority period. Usually, adjustments to baselines and energy savings persistence numbers need to be considered as the early majority period begins. Once the late majority period is reached, a program administrator must consider whether financial incentives are still required to

[7] ACEEE, http://aceee.org/files/proceedings/2008/data/papers/10_56.pdf. Adapted from SoCal Edison
[8] ACEEE, http://aceee.org/portal/market-transformation
[9] ACEEE, http://aceee.org/files/proceedings/2008/data/papers/10_56.pdf. Adapted from SoCal Edison

drive additional market transformation. Quantitative indicators of this point will vary depending on the market and technology. Accordingly, during the early adopter to late majority period where energy efficiency programs are active, incentive setting and review is very important to program success. Program and technology maturity and penetration is a critical consideration during the incentive setting process.

INCENTIVE SETTING THEORY

Incentive setting for energy efficiency programs is a form of price setting, with some unique characteristics. The discussed theory is based on CLEAResult's knowledge and experience with conducting program design and incentive setting exercises, as well as our ongoing discussions with the energy efficiency industry.

PRICE SETTING

Price setting is the process of coming up with the cost of a good or service for a consumer. With price setting, there are two influences:

1. The value a consumer is willing to pay (participant perceived value)
2. The production and distribution costs plus the required premium (return on investment)

The first influence is based on the perceived value for the product or service. This is defined as the value the consumer is willing to pay for a product or service. The second influence is based on the associated return on investment criteria. These two influences must be balanced during any price setting process, as illustrated in Figure 2.

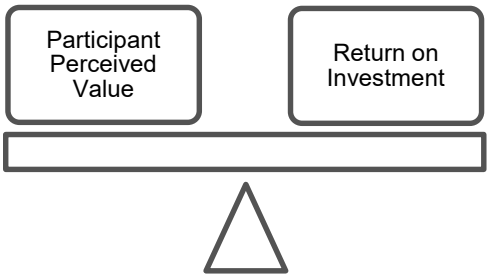


Figure 2: Balance of Price Setting Influences

The return on investment criteria, in most cases, can be quantified and precisely calculated; however, the perceived value to a consumer can only be measured on an individual basis. These individual values can potentially be aggregated, and a representative number for value established, but it is an imprecise exercise, affected both by sample size and the variable nature of a survey response. Additionally, what constitutes value will vary by consumer, depending on their priorities. The value to a consumer can never be known exactly; there is no mathematical formula that can be used to get a precise number. This makes establishing an exact minimum or maximum price extremely difficult.

Participant perceived value curves for sales will typically follow a sigmoid relationship, based on the price elasticity of demand. This relationship is shown in Figure 3, though it is meant to be illustrative. While uptake and incentives generally follow these relationships, it is difficult to quantify precisely. Energy efficient product uptake typically does not increase linearly with increased incentive levels until a critical value is reached.

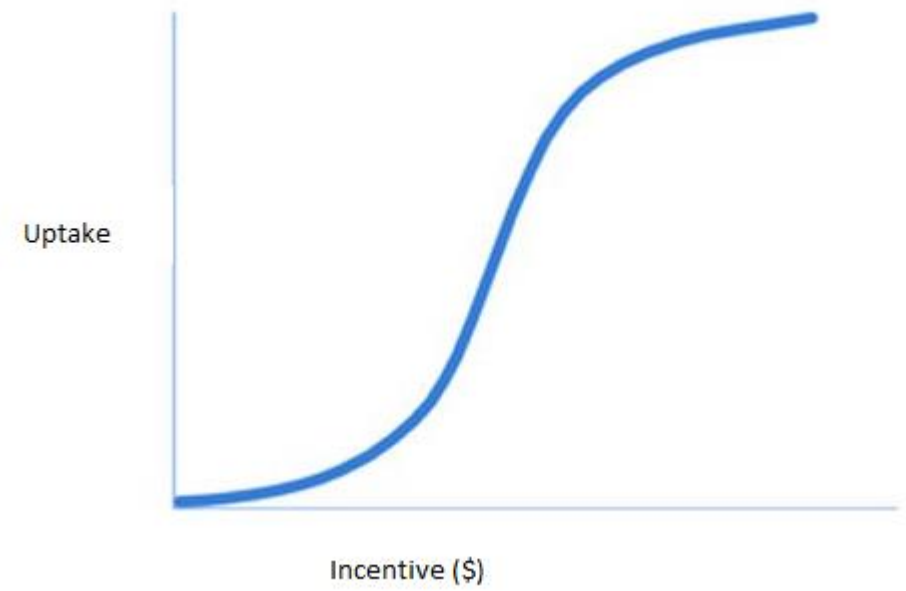


Figure 3: Uptake-Incentive Relationship[10]

Therefore, to identify participant perceived value to better understand how to characterize the curve, firms use several strategies for triangulation.

1. Consumer Surveys
    - Price Sensitivity
    - Conjoint Analysis
2. Research Competitive Products
3. Supply Chain Discussion
4. Jurisdictional Benchmarking
5. Historical Experience

APPLICATION TO ENERGY EFFICIENCY PROGRAMS

As mentioned, incentive setting in energy efficiency programs is a unique form of price setting. For incentive setting in energy efficiency programs, the perceived value to the customer is the driving influence, while the return on investment can assist with setting target expenditure amounts. It should be highlighted that using the analysis from investigating these two influences to set incentives is not a precise exercise.

Due to a general lack of competing incentives from other utilities or agencies, program administrators encounter less immediate, natural compliance (checks and balances) in terms of price setting rigor, other than for budget and reputational risks. In the private sector, an inappropriate price can lead to immediate failure; this risk is only present for program administrators for incentives that are substantially incorrect. This lack of natural compliance is a systemic problem that can be guarded against through applying an incentive setting methodology that features best practices in determining the two key influences to price:

[10] "The 3 Charts That Will Teach You Everything You Need to Know About Business," Business Insider, Available: http://www.businessinsider.com/the-3-charts-that-will-teach-you-everything-you-need-to-know-about-business-2010-7?op=1

participant perceived value and return on investment. Finally, there needs to be a review protocol, which specifies how incentive levels should be reviewed, and if necessary, updated.

PARTICIPANT PERCEIVED VALUE

The determination of the participant perceived value is an evaluation of factors from the participant's perspective.

For energy efficiency programs, participant perceived value leads to the motivation to participate. As discussed earlier, energy efficiency programs feature options that are not standard practice. Therefore, an incentive needs to be deployed to match the customer's perceived value of the energy efficient product or service. Often, the customer looks at much more than just the financial considerations of a decision, but it is a good place to start in determining participant perceived value.

Financial Considerations as Related to Participant Perceived Value

There are several different costs and metrics that may affect the financial considerations involved a participant's perceived value:

1. Retail Price
2. Project Costs
3. Project Payback
4. Incremental Equipment Costs (Participant Costs)

Retail Price: The market price that a customer would have to be pay for the efficient option.

Project Cost: The total upfront costs that a customer would have to pay for the efficient option including purchase and installation.

Project Payback: Some customers will only make purchase decisions based on a project payback meeting a certain maximum amount of years. Before a project payback can be calculated, there needs to be an assessment of the participant's Incremental Equipment Costs.

Incremental Equipment Costs: For incentive-setting, the Incremental Equipment Costs are an assessment of a participant's costs, be it a purchase or usage of a technology or service, when compared to a base case scenario. For the purposes of this study, the Incremental Equipment Costs are defined to include the difference in purchase and installation costs of the efficient equipment or service as compared to a base case. The Incremental Equipment Costs are determined as a Net Present Value (NPV) over the estimated useful life of the efficient option. In other jurisdictions, for specific programs and projects, lifecycle Operations and Maintenance (O&M) costs, and fuel costs, both for the efficient option and the base case, are included in the Incremental Equipment Cost calculation.

Per the above definition of the Incremental Equipment Cost, there are several different types of scenarios and calculation methodologies, which all vary by the status of the base case. As such, determining the base case is critical for Incremental Equipment Cost analysis (as well as other components of incentive setting and broader program design). The common base case scenarios have been outlined in Table 2.

Scenario	General Description
New Purchase/Installation	A customer may decide to make a new purchase for a technology or service. There is not a current technology or service in use. For example, if a customer purchases a new home and they have a choice of different new light fixtures and central air conditioning, since nothing currently exists, the base case would be a New Purchase/Installation scenario. The Incremental Equipment Cost is determined based on the comparison between the efficient technology or service, and the standard technology or service that is available to the customer. The standard technology or service is the base case. The standard technology is often considered to be the most popular technology in terms of sales or penetration at the time, or a hybrid of technology options based on sales or penetration mix assumptions. In some cases, the standard technology can be considered to be non-existent. For example, for a homeowner considering to upgrade their exterior wall insulation, if they currently don't have any insulation or are not planning to get any insulation in absence of the program, the standard technology is the non-insulated wall. The standard service is often considered to be the most popular service offering in terms of sales or penetration at the time. For example, if a program is offering any energy management service, and energy management services are not considered to be standard practice, the standard service could be considered to be not having an energy management service. For this scenario, Incremental Equipment Costs are defined as difference between the efficient option's purchase and installation costs, and those of the base case.
Replacement on Failure/Burnout	A customer may decide to make a purchase of a technology or service after their current technology or service has failed, burned out or expired. The Incremental Equipment Cost is determined based on the comparison between the efficient technology or service, and the standard technology or service. The standard technology or service is the base case. The standard technology is often considered to be the most popular technology in terms of sales or penetration at the time, or a hybrid of technology options based on sales or penetration mix assumptions. It does not need to be the current technology that has burned out. The standard service is often considered to be the most popular service offering in terms of sales or penetration at the time. It does not need to be the current service that has expired. For this scenario, Incremental Equipment Costs are defined as difference between the efficient option's purchase and installation costs, and those of the base case.
Early Replacement	A customer may decide to make a purchase of a technology or service before their current technology or service has failed, burned out or expired. The Incremental Equipment Cost is determined based on the comparison between the efficient technology or service and a combination of two different base cases: 1) The currently installed technology or currently used service for the Remaining Useful Life (RUL) of the currently installed technology or currently used service. The RUL is often estimated at one-third to one-half of the estimated useful life of the technology or service. 2) The standard technology or service for the remaining years from after the RUL throughout the duration of the EUL.

Scenario	General Description
	For example, if a customer was considering buying a new efficient window air conditioner, and their existing window air conditioner still worked, the base cases would as follows: • Year 1 to RUL: Existing Window Air Conditioner • RUL to EUL: Standard Window Air Conditioner The standard technology is often considered to be the most popular technology in terms of sales or penetration at the time, or a hybrid of technology options based on sales or penetration mix assumptions. The standard service is often considered to be the most popular service offering in terms of sales or penetration at the time. This approach to the calculation where a combination of two base cases is used is called the Remaining Useful Life Discounted Incremental Equipment Cost method (RULDICM). This method discounts the material and installation costs of the base case across the Remaining Useful Life of existing equipment, before subtracting them from the material and installation costs of the efficient equipment.
Replacement After Assumed Failure/Burnout	A customer may decide to make a purchase of a technology or service after their current technology or service is supposed to have failed, burned out or expired, but is still continuing to function. The Incremental Equipment Cost calculation is treated the same as the Early Replacement scenario. Even though the current technology or service is supposed to have failed, burned out or expired, it is still assigned an appropriate RUL.

Table 2: Incremental Equipment Cost Scenarios

A participant might look at one, a combination of some, or all of the above factors in their financial analysis of a purchase decision. In addition, they may conduct their own version of the Participant Cost (PC) test.

Participant Cost Test

In evaluating a participant's purchase decision from a financial perspective, the PC test is a useful analysis to deploy. It assesses all of the direct financial considerations that a participant faces in making a purchase decision, and indicates whether the financial benefits are greater than the financial costs.

General Description of PC Test	Influence of PC Test on Incentive Levels
The PC test is an evaluation of the financial benefits of a technology or service compared to the financial costs, from the perspective of the participant. The financial benefits include incentives, tax credits and utility bill savings. The benefits are evaluated throughout the estimated lifetime of the product or service, with an NPV determined using a set discount rate. The financial costs are the total costs to the participant to purchase, install and maintain the equipment or service, compared to the base case. The utility bill savings should not be included in this calculation, since they are considered in the financial benefits, and should not be double-counted. The costs are evaluated throughout the estimated lifetime of the product or service, with an NPV determined using a set discount rate.	The PC test can be used in incentive setting, since it allows the program administrator to quantify the financial impact that a technology or service has on a participant. The financial impact can be closely correlated to a participant's perceived value of a technology, especially for more sophisticated commercial and industrial customers who primarily make purchase decisions based on financial metrics. For example, if a PC test ratio is below 1.0, it indicates that the customer will not achieve payback on their purchase, and the incentive may have to be increased for the customer to be motivated to purchase. Depending on the program and jurisdiction, program administrators may have their own internal targets for PC test, which are often reflected through payback metrics. These metrics depend on the value of the incentive.

The PC test is typically reported as a ratio (benefits/costs). A ratio over 1.0 indicates that the benefits are greater than the costs.	

Table 3: Participant Cost Test and Relationship to Incentive Setting from a Participant Perceived Value Perspective

The analysis involved in determining the Incremental Equipment Cost and the PC test involve some of the same components. Both types of analyses require a definition of the base case, and a calculation of the cost differences between the efficient option and the base case. As discussed, the Incremental Equipment Cost can be broadened to include O&M and fuel costs, based on the specific program, measure, technology or project.



Figure 4: Components of Incremental Equipment Cost and Participant Cost Test

As required, the individual components may require an NPV analysis and discounting, depending on when the components are incurred.

Broader Considerations as Related to Participant Perceived Value

In the real world, determining participant perceived value during price-setting should not be thought of as a precise science that is only based on financial quantification. The same holds true for incentive setting within energy efficiency programs. While it may be possible to determine a customer's financial perspective as viewed through multiple lenses (e.g. retail price, project costs), there are broader considerations that affect a participant's perceived value. These considerations might not always be directly quantifiable. However, there are some key activities and processes that should be used when conducting incentive-setting exercises to assist with determining participant perceived value and the value of a potential incentive. These activities and processes are applicable to determining both the financial considerations, and the broader considerations associated with a participant's perceived value.

Customer Research

A critical component of determining participant perceived value is actually asking potential customers what they would pay for a product or service, and what their price points are for difficult technology options. Additionally, asking customers what other barriers they face in making a purchase decision can help determine incentive values. For example, the financial considerations associated with the purchase of Compact Fluorescent Lamps (CFLs) a few years ago indicated that customers should be motivated to purchase them; however, CFLs reached a saturation point where adoption stalled due to light quality and environmental concerns due to the presence of mercury; elements that the financial considerations did not capture.

Based on the Incremental Equipment Cost and PC analysis for Residential LED A Lamps, again, it would seem that customers should be motivated to purchase them. While Residential LED A Lamps are some of the most popular DSM measures in North America, they still have not become standard practice due to the feeling of customers that the upfront retail costs are still too high.

The customer research can be done directly through focus groups and surveys. With any incentive-setting exercise, it is important to get customer input frequently. It is also important to understand the greater picture surrounding the customer's purchase decisions. This perspective can often be answered by asking the following questions:

- What is their value proposition for moving forward?
- What do they think of their options?
- What are their primary barriers to moving forward?
- What are their challenges with the existing standard option?

This research is especially important when there are multiple potential customers/stakeholders for an efficiency project, and they have different motivations and barriers. This is often called the principal-agent problem and is most commonly encountered in rental units, where tenants and landlords have different motivations, based on:

- Which party is responsible for paying the energy bills;
- The structure for how the bill is determined and who makes the spending decisions for new equipment; and
- Who has the right to upgrade that equipment?

Incentives and their associated delivery strategies need to be considered carefully in attempting to solve barriers in these situations.

Technology Research

Technology research is essential when identifying participant perceived value as well as completing other analysis associated with incentive setting. The three forecasts that need to be developed are:

- Market price;
- Technology penetration; and
- Technology performance.

It is important to know the price points for the different technologies and options. Additionally, understanding current and future market pricing and the impact on incremental equipment costs is essential in developing an incentive strategy. Pricing considerations can include upfront capital costs, labour costs for installation, operations and maintenance costs, etc.

Finally, it is important to consider limitations and how the technology is expected to evolve over the short to long-term (next few months to a one to two year) period. This analysis is critical for technology performance and setting energy consumption baselines, energy persistence values and incremental equipment costs. All of these factors are usually analyzed during the review and update of the Technical Reference Manual (TRM), which typically contains measure assumptions.

After gathering the required information from the Technology Research, it should be possible to determine the inputs for cost effectiveness calculations and financial analysis from the participant's, the program administrator's and society's perspective.

Supply Chain and Stakeholder Discussion

In designing and delivering any best-in-class energy efficiency program, it is important to involve the supply chain and key stakeholders such as industry associations, other government agencies and community groups. Often, they can help with both customer and technology research, especially with providing supporting information and access to their contacts. They can also provide insight into their costs which can help shape the incentive-setting analysis. Finally, the supply chain and stakeholders can identify if there are other barriers or considerations in the market that need to be addressed through the incentive, or broader program design. For example, if an energy efficiency program targeted at commercial refrigeration used a direct install approach where only one centrally-procured contractor was able to install the equipment, and the target customers all wanted to use their own contractors due to trust and familiarity, then the value of the financial incentive may need to be adjusted, or the delivery strategy changed.

For optimal program delivery, the supply chain and stakeholders should also review potential incentive changes and be provided notice to prepare for those changes. Additionally, if the supply chain will be a critical component of a program's go-to-market strategy, it is important to determine the supply chain's barriers to participation. For example, if the program is a midstream lighting program delivered by distributors, it is important to know what the distributors' barriers are and what incentive will be required for them to stock, promote and sell the efficient products.

Another important element to the supply chain and stakeholder discussion is to determine if there are other incentives in the market that are not offered by program administrators. It is likely that the supply chain and stakeholders will be aware of these incentives, since they are a common vehicle for customers to learn about all of the incentives present in a market and help take advantage of them. Examples of other incentives for energy efficiency programs can be things like tax rebates, government incentives through other vehicles or other offers such as low cost financing on certain purchases.

Benchmarking

If an incentive or technology is new, there may not be any historical data to assist with forecasting price and penetration curves in a utility's local market. Benchmarking incentive rates against similar technologies or programs in other jurisdictions can mitigate this lack of local data. However, it should be noted that not only considering the disparity between the Canadian and U.S. dollar, some products and services have significantly different costs due to regulatory, infrastructure, supply chain, environmental and demographic factors.

To address the issue of the comparison of different jurisdictions, incentives in one jurisdiction can be established by referring to incentives in a comparable jurisdiction (direct benchmarking). A comparable jurisdiction may be determined through the evaluation of population size, population demographics, climate, housing and building characteristics etc. A second option to address the issue of comparing different jurisdictions is involves explicitly accounting for the differences by making adjustments. For example, for comparison between Nova Scotia and Maine, an adjustment can be made to pricing based on the currency exchange rate. However, making adjustments for differences will not be an exact science.

An important element of benchmarking is to open up a dialogue with the other jurisdictions, if possible, to understand the nuances in the market and program delivery structure and how they may affect incentives. Any benchmarking exercise should consider these differences.

Program Evaluation Review and Historical Experience

The final consideration in determining participant perceived value is reviewing previous evaluation reports and accounting for historical experience. Program evaluations typically include an analysis of barriers, customer and supply chain insight and recommendations for improvement. They also provide quantitative performance information regarding participation, savings and, depending on the jurisdiction, expenditure. Historical experience allows program administrators to understand the uptake implications of previous incentives. For example, if an incentive for an individual LED A Lamp was $8.00, and the measure

uptake was significantly above the forecasted participation rates and allocated budget, the historical experience may indicate the need to lower the incentive rate.

RETURN ON INVESTMENT

The determination of the return on investment is an evaluation of factors from the program administrator's and broader society's perspective.

For efficiency programs, return on investment is based on two general considerations:

1. Cost effectiveness
2. Budget impact.

Cost Effectiveness

Cost effectiveness is usually determined using a benefit-cost analysis which explicitly or implicitly compares the cost of energy efficiency to other electricity or natural gas supply resources and may include other considerations (e.g., environmental benefits). The two common explicit cost effectiveness tests used in determining return on investment with regards to incentive setting are the Total Resource Cost (TRC) and the Program Administrator Cost (PAC) tests.

In addition to using cost effectiveness tests explicitly, there may be an opportunity to use unit costs based on lifetime energy savings. If these unit costs are below a certain target value, it serves as another potential indicator of cost effectiveness.

Cost Effectiveness Test	General Description and Features	Implication for Incentive Setting
TRC	The TRC is an evaluation of the total utility and participant benefits (both energy and non-energy benefits) compared to the utility and participant costs. The benefits are typically quantified as the avoided costs of supply and distribution for all resource savings (electricity, natural gas, water) as well as any non-energy benefit considerations. The program administration costs are the costs to the program administrator to run the program, excluding financial incentives. The participant costs are the total costs to the participant to purchase, install and maintain the equipment or service, compared to the base case. Incentives are not included in the participant cost calculation for the TRC. The utility benefits are evaluated during the lifetime of the assumed savings persistence, with a Net Present Value (NPV) determined, using a set discount rate. The program administration costs and participant costs are evaluated during the estimated lifetime of the product or service, with an NPV determined using a set discount rate. The program administration costs are often paid up front, without a need for discounting and future cash flow analysis. For simplicity of calculation, the assumed savings persistence and the estimated useful life are often set at the same value. The TRC can be reported as a ratio (benefits/costs) or as a net benefit (benefits-costs). A ratio over 1.0 indicates that the benefits are greater than the costs.	The TRC does not include the incentive in its calculation directly, though by including all participant costs, the incentive amount is included as a sub-set of the participant cost, provided the incentive is less than the participant cost. NEBs used in the TRC should be consistent with the guidance of Nova Scotia's DSM Advisory Group (DSMAG).
PAC	The PAC is an evaluation of the total utility benefits of a technology or service for society compared to the utility costs. For electricity efficiency and conservation programs, the utility benefits are typically quantified as the avoided costs of supply and distribution for electricity. The utility costs are composed of program administration costs and incentive costs. The program administration costs are the costs to the program administrator to run the program, excluding financial incentives. The utility conservation benefits are evaluated during the lifetime of the assumed savings persistence, with a Net Present Value (NPV) determined, using a set discount rate. The program administration costs and the incentive costs are evaluated during the estimated lifetime of the product or service, with an NPV determined using a set discount rate. Both the program administration costs and the incentive costs are often paid up front, without a need for discounting and future cash flow analysis. For simplicity of calculation, the assumed savings persistence and the estimated useful life are often set at the same value.	The PAC can be used in incentive setting. It forms the basis of the PAC Benefits (Cost Effectiveness) incentive threshold which is discussed later in this report. Depending on the program and the jurisdiction, program administrators may have their own internal targets for the PAC, which can affect the amount of money available for the incentive.

Cost Effectiveness Test	General Description and Features	Implication for Incentive Setting
	The PAC can be reported as a ratio (benefits/costs) or as a net benefit (benefits-costs). A ratio over 1.0 indicates that the benefits are greater than the costs.	
PC	The PC is an evaluation of the participant's financial perspective to participate. It quantifies the financial benefits and costs to the participant over the lifetime of the measure, with NPV used with a set discount rate. The PC is not an approved cost effectiveness test by the URB.	As discussed later in the report, the PC evaluates a participant's financial perspective. If it is found while calculating the PC that a participant's costs are greater than their financial benefits, it indicates the opportunity to increase an incentive to get the PC to a desired level.

Table 4: Cost Effectiveness Tests and Relationship to Incentive Setting from a Return on Investment Perspective

Budget Impact

Program administrators are not only affected by cost effectiveness concerns when determining their return on investment. From CLEAResult's experience, in several jurisdictions, the program budget is usually the limiting factor for expenditure; not cost effectiveness. These budget-limited programs by default are cost effective if they generate the required lifetime net energy savings within the assigned budget.

An incentive may be cost effective, but may not fit within a program budget. Therefore, the budget impact needs to be considered in addition to cost effectiveness as the budget may set the financial ceiling.

The budget impact should be considered not only on a per unit savings basis, but also on a per participant basis and on a total budget impact basis. An incentive may be considered great value for money on a per unit savings basis, but due to high potential uptake, it may not make sense for the program budget.

Return on investment criteria typically set ceilings for incentives in energy efficiency programs. They ensure a minimum return for both the program administrator and society. However, incentives are often set at values far below the return on investment ceiling, since the considerations involved in determining participant perceived value typically triangulate an incentive at a lower value.

THEORETICAL THRESHOLDS FOR INCENTIVES

Based on the return on investment criteria as well as perceived value considerations, there are three theoretical thresholds for incentives that are based on quantitative analysis:

1. Customer Cost
2. PAC Benefits (Cost Effectiveness)
3. Budget

Customer Cost Threshold

The Customer Cost theoretical threshold for incentive setting is based on a customer's perception of what they are paying for a product. There are several considerations that may go into determining Customer Cost (since customers evaluate their costs differently depending on the situation), and the parameter that is chosen to represent the Customer Cost is dependent on the combination of the customer, the efficient option and the replacement decision. There are several different parameters that can be considered including retail price, project cost, Incremental Equipment Cost and Participant Cost test/project payback.

Retail Price: Retail price is one of the first parameters to be considered. It is the market price that a customer would have to be pay for the efficient option.

Project Cost: For some efficient options, retail prices are not comprehensive in determining the cost to the customer. For example, some efficient options require installation and maintenance costs. These costs may not be included in retail pricing, but contribute to the customer's costs.

Incremental Equipment Cost: As discussed earlier, the Incremental Equipment Cost can be thought of as the difference in costs between the efficient option and the standard option.

Participant Cost Test/ Project Payback: Instead of providing customers with Participant Cost Test results, payback analysis is a simpler method of communicating the benefits of making a purchase decision for an efficient option. For example, it is much easier to tell a customer that their purchase decision will pay back within 2-3 years, instead of providing them with a Participant Cost test ratio that is greater than 1.0, which indicates that their NPV is positive. Sophisticated commercial customers will evaluate both NPV and payback analysis, but residential customers and smaller, less sophisticated commercial customers may not; as such, this information is useful to them.

Additionally, even if an efficient option has an attractive payback, there may still be challenges with access to upfront capital that an upfront incentive and/or financing offer can solve.

All of the above considerations (retail price, project cost, Incremental Equipment Cost, Participant Cost Test/payback analysis) contribute to the Customer Cost, depending on the type of customer, the efficient option and the replacement decision. A key focus of the customer, technology and supply chain research is to determine which Customer Cost threshold is applicable to the customer, if there is a combination of different parameters that need to be accounted for in incentive design, and if there is an opportunity for customer education (e.g. the Retail Price is very high, but the Participant Cost test shows that the efficient option will generate a positive NPV over the lifetime of the technology or service).

In Table 5 below, CLEAResult has provided suggestions for the Customer Cost threshold for different combinations of customers, technologies and replacement scenario. These suggestions are based on CLEAResult's program design and program management experience; they should be confirmed through the research activities involved in determining a participant's perceived value.

Unique Combination	Customer Cost Considered	Rationale for Selection
Residential Customer LED A Lamp Purchase Current Incandescent A Lamp Burned Out (Replacement on Burnout)	Retail Price	Residential customers for small purchases look at retail price. They do not typically look at Incremental Equipment Cost analysis or payback when making small purchases. As such, when setting incentive levels for this specific combination of customer, technology and replacement decision, the cost to customer threshold may be best aligned with retail price.
Residential Customer New Air Source Heat Pump Purchase Current Electric Baseboard is Working (New Purchase)	Project Costs, Incremental Equipment Cost, Payback	Residential customers for larger purchases will look at a combination of upfront costs and utility bill savings. They may look at purchases in terms of payback. As such, when setting incentive levels for this specific combination of customer, technology and replacement decision, the cost to customer threshold may be best aligned with the project costs as well as the Incremental Equipment Cost and payback.
Commercial Customer New Chiller Current Chiller is Working (Early Replacement)	Project Costs, Incremental Equipment Cost, Payback	Commercial customers for larger purchases will look at a combination of upfront costs, lifecycle operations and maintenance costs including utility bill savings, as well as the project payback. As such, when setting incentive levels for this specific combination of customer, technology and replacement decision, the cost to customer threshold may be best aligned with the project costs as well as the Incremental Equipment Cost and payback.

Table 5: Selection of Parameter for Customer Cost

After the appropriate Customer Cost parameter has been selected based on the different research activities, a percentage, proportion or limit can be assigned to develop the incentive level. For example, certain jurisdictions may have the principle that incentives should not be higher than 50% of the appropriate cost to customer. Another popular cost to the customer threshold for the commercial and industrial sectors is limiting incentives to a maximum that produces a two year payback.

As can be seen in the Recommendations, a full financial analysis should be documented for all incentive-setting including analysis of both current and estimated future retail pricing, Incremental Equipment Costs, running the Participant Cost Test, conducting measure-level TRC and PAC analysis, and assessing the budget and cost effectiveness impacts of the incentives.

PAC Benefits (Cost Effectiveness) Threshold

The PAC is the cost effectiveness test that reflects a program administrator's financial expenditure for a measure, program or portfolio. It is calculated by dividing the PAC benefits, which are the avoided supply and distribution costs of the electricity savings, by the PAC costs, which is the financial expenditure (program administrator costs for program overhead and delivery and incentive costs). At the measure level, PAC costs may include an assumption adder for program overhead and delivery costs, or may only include the incentive costs alone.

The PAC benefits are a financial quantification of a measure, program or portfolio's value to the electricity system, using the Avoided Costs. As discussed earlier, incentives are usually the largest component of a utility budget. As such, the PAC Benefits of a measure, program or portfolio provide a natural limit for incentives (when adjusted for overhead costs); Incentives (when adjusted for overhead costs) ideally should not be higher than the measure-level PAC benefits of a measure.

While most jurisdictions have a minimum requirement for measures, programs and portfolios to have a minimum PAC of 1.0, and remain cost effective, often incentive setting, program design and portfolio design can be developed to meet a higher PAC. For example, if a target PAC is 2.0, it means that incentives and overhead costs are limited to 50% of the PAC benefits.

Budget Threshold

Measure level, program or portfolio budgets can also limit incentive levels. For example, for high-volume measures, there may be an overall budgetary restriction due to the volume risk of participation. Additionally, certain jurisdictions may limit incentive spending using unitary savings metrics like $/kWh or $/kW. For example, if a jurisdiction has a total budget allocation of $0.30/kWh for their portfolio, there may be caution regarding setting any incentive levels higher than this amount. While all jurisdictions feature a certain level of portfolio management, with $/kWh spending in the commercial and industrial sectors typically lower than the residential sector, a balance must still be maintained, and as such, incentives may be limited by available budget.

Application of Thresholds

Incentives can exceed all three of these thresholds (and often do), but they provide a reference point that can be used during the design process. The thresholds are independent of one another. They can all contribute to the concept of a maximum eligible incentive for a measure that program designers can use during the incentive setting process.

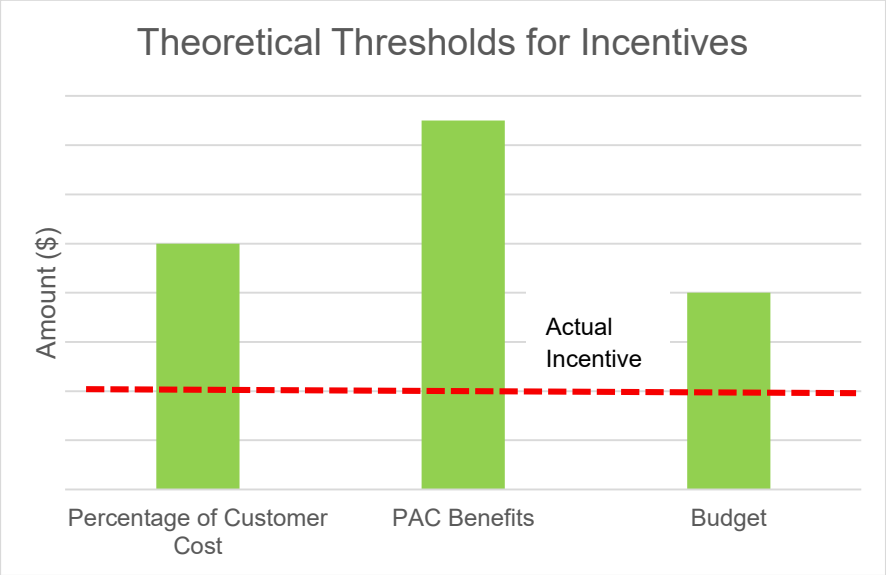


Figure 5: Theoretical Limits for Incentives

For any particular measure, any one of the theoretical limits can be the lowest or highest value.

The Role of Financing

If upfront costs are an issue, but not monthly or annual cash flows, the provision of low-interest or zero-interest financing may be valued by customers, either as a stand-alone incentive, or in combination with an upfront incentive. Program situations where financing may be attractive are when the customer has a PC test ratio greater than 1.0 and when the project payback analysis meets the customer's internal targets, but the upfront costs to purchase the efficient option requires more capital than the customer has available. The provision of financing is able to alleviate the issue of limited upfront capital, with the customer still being able to tolerate the impact on their monthly or annual cash flows.

From CLEAResult's energy efficiency program design and program delivery perspective, customers almost always prefer an upfront incentive to low-interest or zero-interest financing if both options are mutually exclusive.

It should be noted that the NPV of financing costs can be included in the analysis of the thresholds for the program budget and PAC.

The Importance of Education and Awareness

In almost all cases, education and awareness initiatives play a key role in motivating the customer to make a purchase decision. While educational incentives are not specifically discussed in this report, it is important to acknowledge that important role that they play in removing barriers to customer participation. Educational initiatives can also assist with the goal of achieving reduction in incentive levels; for example, if a measure makes financial sense for a customer to install, but the customer is just not aware of the financial benefits and is thus not participating, education and awareness can bridge this gap.

Education and awareness initiatives can also remove non-financial barriers from participation, such as a lack of knowledge about a program, technology, or service.

SUMMARY OF INFLUENCES ON INCENTIVE RATES

The different components involved in incentive setting are listed below in Table 6. The table lists how a change in each component can influence measure level incentives. This highlights the multiple considerations that must be taken by program administrators when setting or altering incentives. In some cases, factors can create either upward pressure or downward pressure on incentives, depending on the specific situation. The considerations lend credence to the feedback obtained from many of the interviewees during the jurisdictional scans who echoed that setting incentive is "as much art as science."

Incentive Setting Component	Factors that can Place Upwards Pressure on Incentive Rates	Factors that can Place Downwards Pressure on Incentive Rates
Budget Impact	• Reduction in administration costs, leaving additional space in the budget. If there is a need to increase participation, increasing incentives may be an option	• If the budget is at risk of being exceeded, lower incentives may be required • Budget impact considerations can set ceilings on incentive levels
Customer Research	• Customers indicate that the incentive is not sufficient to motivate them to participate • There may be a lack of awareness of the technology, program or measure	• Customers indicate that the incentive offer is very attractive, and they may have participated even if the incentive was lower
Technology Research	• The technology has a forecasted increase in costs within the next program period	• The technology has a forecasted drop in costs or increase in market penetration within the next program period • Technology baselines are adjusted such that the Incremental Equipment Cost of the incented measure is lower, thus supporting the reduction in incentive
Supply Chain and Stakeholder Discussion	• Additional barriers are identified, which require more or increased incentives to address (e.g., distributors are unwilling to stock efficient products due to lack of perceived market demand)	• The program delivery structure may leverage cheaper supply chain costs, resulting in a reduction in the incremental equipment cost which may justify a smaller incentive
Benchmarking	• Comparable jurisdictions offer a significantly higher incentive drawing investment and supply chain participation to their market	• Should the majority of other comparable jurisdictions have significantly lower incentive rates for specific measures, it may indicate a change in market conditions which can support a reduced incentive rate
Program Evaluation Review and Historical Experience	• Program evaluation suggests poor program and market performance due to lack of financial incentive	• Program evaluation suggests customers are motivated by other influences outside of the financial incentive
Financing	• Financing is removed or not offered for measures where it is indicated that a barrier for participation is the upfront capital cost	• Financing is included to complement or replace incentives for measures, which should result in incentives being reduced
Education and Awareness	• The benefits (financial or otherwise) of a measure are not included in the customer information materials and messaging, leading to the need for increased incentives to stimulate uptake	• Education and awareness is included to indicate to customers that the efficient measure pays for itself during its lifecycle due to bill savings, leading to reduced incentives

Table 6: Summary of Influences on Incentive Rates

INCENTIVE RATE REVIEW PROTOCOL

After determining incentive values by analyzing the considerations that determine the two influences (perceived value, return on investment) of incentive setting, the final requirement is to establish and follow a review protocol.

In some commercial environments, the review protocol is ongoing. For energy efficiency programs, it is best to review incentives on a periodic basis (ranging from quarterly to every two years). Periodic review is needed because, while certain elements can be ongoing, such as continuing customer and technology research, there are also standing engagement mechanisms that involve the supply chain and key stakeholders. The review frequency is determined by the program delivery structure, the rate of market transformation and the incentive expenditure. It is acceptable to have different review frequencies for different technologies and programs.

Ideally, if there is budget and resources to conduct reviews, each incentive level should be reviewed annually at minimum. However, in some cases, a two year review process may be justifiable. Even if incentive levels cannot be reviewed comprehensively every year, the market price of the measure should always be updated. For certain technologies that either have high participation, are quickly evolving or both, it is important to assess incentive levels more frequently. For example, a quarterly assessment may be appropriate, but it can be a light touch assessment, provided that key metrics are tracked during the program record keeping process. For technologies that are either more mature, do not naturally have a high uptake due to niche application or both, there is less risk in having an annual incentive review process.

The other element of the review protocol is to list the factors for consideration, and how each factor will be assessed. These factors include:

- the price a customer will pay for the product;
- the price and penetration curve of the technology;
- the Incremental Equipment Costs and the Participant Cost Test
- the forecasted change in savings over time;
- the supply chain and stakeholder discussion;
- benchmarking;
- program evaluation;
- historical program performance review; and
- the financial impacts
    - Cost Effectiveness Impacts
    - Budget Impacts.

In some cases, certain factors will be clear regarding analysis and recommendations, and in other cases, there will be additional work required. It is important to establish and understand the tolerance for these factors.

Jurisdictional Research

JURISDICTION IDENTIFICATION AND SELECTION

The selected jurisdictions were as follows:

- Ontario (IESO);
- Ontario (Union Gas);
- British Columbia (BC Hydro);
- California (PG&E);
- Oregon (Energy Trust of Oregon);
- Washington (Energy Trust of Oregon);
- New York (Con Ed);
- New York (NYSERDA);
- Vermont (Efficiency Vermont);
- Maine (Efficiency Maine); and
- Massachusetts (National Grid).

The jurisdictions were chosen for one or more of the following reasons:

- considered best-in-class;
- similar size to Nova Scotia;
- similar market structure, energy efficiency policy environment and energy efficiency program delivery structure to Nova Scotia; and
- similar climate to Nova Scotia.

BEST-IN-CLASS

In Canada, Ontario and British Columbia have the largest energy efficiency budgets and the longest history of designing and delivering energy conservation programs. They are also usually considered the leading provinces for promoting energy efficiency.

In the United States, the American Council for an Energy-Efficient Economy (ACEEE) 2015 State Efficiency Scorecard had the following results:[11]

[11] The 2015 State Energy Efficiency Scorecard, ACEEE, October 2015, Available: http://aceee.org/sites/default/files/publications/researchreports/u1509.pdf

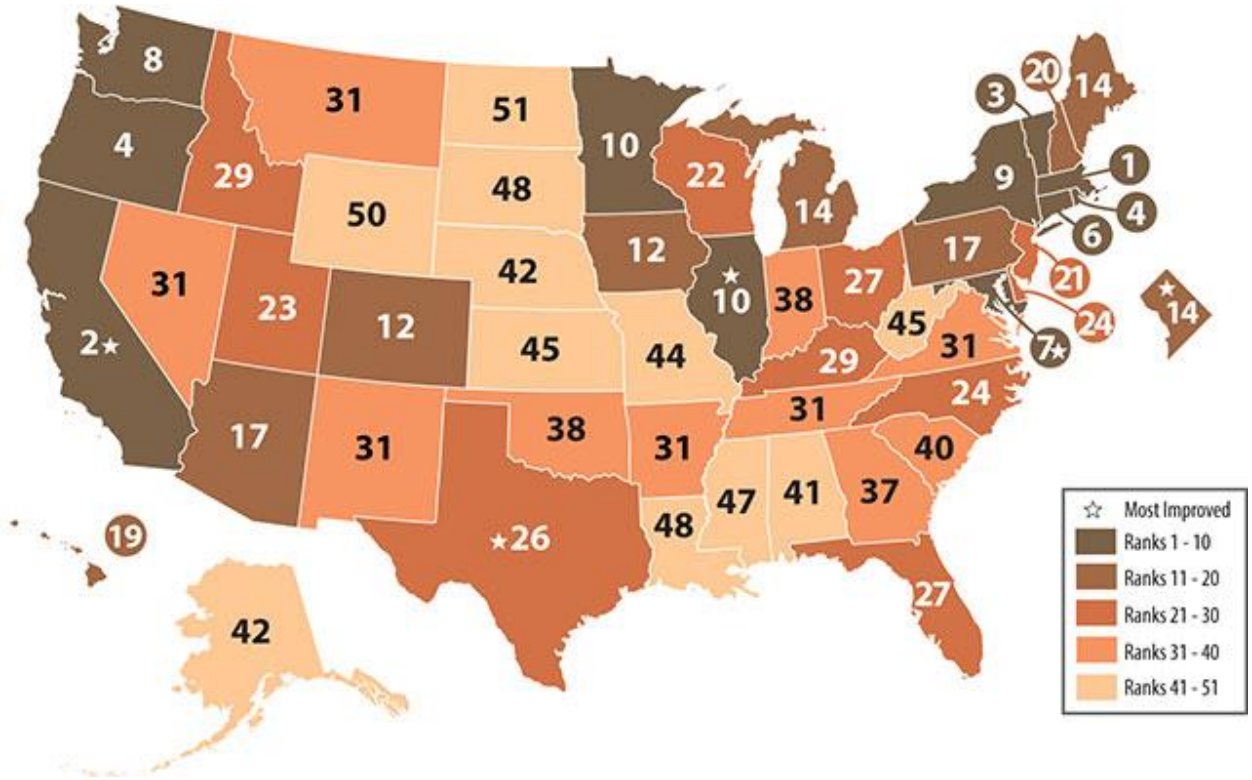


Figure 6: ACEEE State Energy Efficiency Scorecard

The American jurisdictions scanned in this report all rank in the top ten of the 2015 edition of the ACEEE scorecard, other than Maine, which is ranked at 14 out of 51 jurisdictions. The scorecard ranks the states based on criteria that reviews their policy and program efforts, their recent performance, identified best practices and leadership. All of the American jurisdictions selected have long-term Energy Efficiency Resource Standards (EERS), which demonstrate their commitment to energy efficiency as a sustainable form of electricity supply.

SIZE, STRUCTURE AND CLIMATE

Vermont, Maine and National Grid in Massachusetts all serve a similar population to ENS's programs. In terms of budget magnitudes, stock and sales data, and electricity savings targets, their similarity in size allows for comparative analysis. Efficiency Maine and Efficiency Vermont have very similar market structures to ENS, with all three serving as energy efficiency utilities.

Jurisdictions such as BC Hydro, IESO in the Ontario electricity sector, NYSERDA and the three utility companies in National Grid, New York Con Ed and PG&E, all have very different electricity systems, policy goals and oversight structures. They were selected to obtain the full spectrum of environments for which incentives can be set and offered. Union Gas was selected to offer a strictly natural gas energy efficiency perspective. Finally, jurisdictions in Maine, Vermont and Massachusetts were chosen as they have similar climates to Nova Scotia, so the types of efficiency technologies in the market, especially for HVAC and building envelope, are similar.

FINDINGS AND IDENTIFIED BEST PRACTICES

Our jurisdictional research has shown that the majority of jurisdictions employ similar methodologies and approaches to setting incentives. All of the jurisdictions have broad program design, TRM and/or market research processes, but there was not a consolidated, specific process on incentive-setting alone. While there are many detailed nuances which differ from jurisdiction

to jurisdiction (e.g., how they conduct supply chain research), our research has shown that the general framework and best practices for setting incentive rates follow the workflow highlighted below. It is important to note that the workflow does not necessarily represent concrete, sequential steps, as setting incentives is typically a process which incorporates all of the considerations described with analysis performed in parallel.

It is important to note that our research indicates that EfficiencyOne also performs many of these steps at a high-level; as such, our recommendations provided later in this document are focused on the details and nuances.

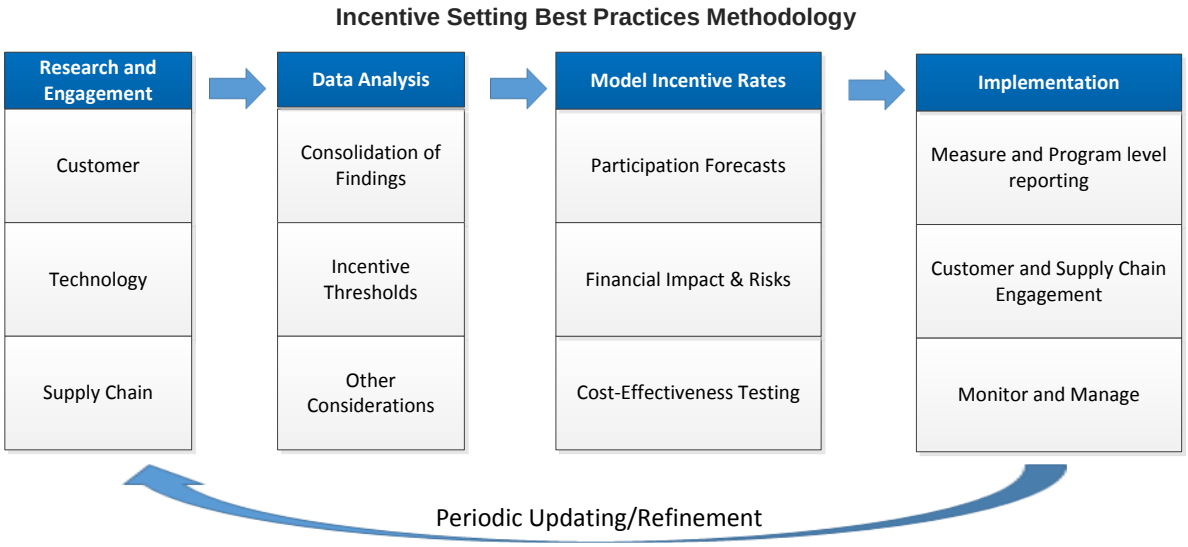


Figure 7: Identified Incentive Setting Best Practices Methodology

Research and Engagement Phase			
General Principle	Definition	Examples	Identified Best Practice
Customer Research	Most jurisdictions studied undertake customer research (either primary or secondary) to identify the motivations to participate in energy efficiency programs and the barriers preventing participation in specific programs or generally in energy efficiency initiatives.	PG&E holds periodic non-residential focus groups used to gather customer barriers and required incentives for moving forward. The Energy Trust of Oregon is mindful of the impact of incentive rates on the market barriers identified during its structured measure and incentive development process. Efficiency Vermont performs market analysis to assess market drivers and barriers as well as the customer value proposition. Efficiency Vermont outlines this information in the Draft Product Brief document. BC Hydro conducts primary research such as one-on-one consultations for larger customers. The objective is to determine awareness, barriers and purchase decisions.	Program administrators perform periodic studies with key participant groups to determine the following: • How customer motivations to participate have changed • How customer barriers to participation have evolved • The impact of existing incentives on participant behaviour The program evaluation process can be an appropriate means to perform this research. For new measures, this process should be undertaken at the outset of incentive development.
Technology Research	This research is conducted with the goal of understanding the savings opportunity for the technology, and to establish a range for the incentive level. All of the jurisdictions investigated identified this as a key element of their incentive setting practices. This phase can include benchmarking to obtain the required data from comparable jurisdictions.	PG&E will perform primary and secondary market research to determine measure performance and metrics. National Grid contributes to the Massachusetts Technical Advisory Committee (MTAC). The Committee reviews new energy efficiency technologies and publishes threshold technical requirements for qualifying products or processes to enable them to become eligible for incentives. Multiple jurisdictions create documents similar to TRMs. For example: Efficiency Maine's Residential and Commercial TRM provides documentation for energy and demand savings calculation of measures and operates as a common point of reference for the methods, formulas, assumptions and sources used. The Commission of Con Ed New York's market approves of technical manuals to provide a uniform, measure-specific approach to estimate the energy and demand savings for measures.	Program administrators maintain a resource similar to a TRM which contains the following information: • Measure savings vs. baseline • Assumptions and calculations used in calculating savings • Current status of baseline and efficiency technology in market

Research and Engagement Phase			
General Principle	Definition	Examples	Identified Best Practice
		The Energy Trust of Oregon will examine other jurisdictions' incentive rates when introducing new measures to its portfolio. For weather sensitive measures, it will examine jurisdictions which experience similar annual weather conditions.	
Supply Chain Research	Surveying the supply chain and service providers is extremely valuable during the incentive setting process. They can provide additional insight into customer barriers and motivations. Through product price research, they can assist in providing a point of reference to update or create incentive levels. Lastly, their feedback can be used to improve program delivery.	PG&E will hold on-camera interviews with distributors and manufacturers to determine measure price points and Incremental Equipment Costs as well as verify measure performance. The Energy Trust of Oregon is mindful of how incentive levels will influence the stocking levels of suppliers and distributors. Efficiency Vermont conducts market testing during the New Product Development process (their process for new program design). This involves testing the product prototype with customers and key stakeholders before launch.	Program administrators perform research in supply chains for their key measures to determine: • Baseline and efficient measure costs • Highlight the major barriers to participation found through customers interactions • Provide feedback on program delivery strategies • Determine how incentive rates in market will alter their business strategies

Table 7: Research Engagement Phase

Data Analysis Phase			
General Principle	Definition	Examples	Identified Best Practice
Consolidation of Findings	Once the research and engagement phase is completed, findings must be compiled to be analyzed and weighed against each other. This sets the first stage for setting incentive rates.	The Energy Trust of Oregon undertakes this exercise during the Preliminary Measure Development stage of its Measure Development and Revision Process.	Program administrators include in their TRM (recommended above) or in separate documentation the major barriers identified in market and the potential means to address them.
Incentive Threshold Setting	Through the supply chain and customer research, the thresholds of Incremental Equipment Cost and the customer's willingness to pay can be determined to act as points of reference for further stages in the incentive development process.	PG&E will set a maximum incentive rate which is roughly 75-100% of Incremental Equipment Cost identified in the Research Phase.	Program administrators: • Capture Incremental Equipment Costs • Capture desired incentive rates from market participants

Data Analysis Phase			
General Principle	Definition	Examples	Identified Best Practice
			• Capture incentive rates used in benchmark jurisdictions (for new incentives) • Develop target budget and cost effectiveness thresholds
Other Considerations	When considering the inclusion of a measure in programs, efficiency administrators may include other considerations aside from the measure savings potential and the measure costs. These varied by jurisdiction but were driven by factors such as policy goals, supply chain availability, market readiness, go-to-market strategy, etc.	While NYSERDA will typically cap commercial incentive rates at 50% of project costs, it allows up to 70% of project cost to be incented for agricultural customers in order to promote energy efficiency in that sector.	Program administrators identify the key driving considerations related to individual measures and ensure that they are addressed in the Incentive Rate Modelling Phase as much as other constraints allow.

Table 8: Data Analysis Phase

Model Incentive Rates			
General Principle	Definition	Examples	Identified Best Practice
Participation Forecasts	To determine the impact of the measure on the total savings target and budget, it is critical to create a participation forecast.	In Ontario, the IESO requires that any new program or measure be approved through a formal business case submission process which includes a program participation forecast. Efficiency Vermont, through the new product development process, will estimate the total size of the market for that measure in order to forecast potential measure uptake.	A measure forecast should be created in order to determine the required program delivery approach and total budget impact. The best practices for determining participation forecasts are using historical experience and the total and achievable market size as indicators. If there other available incentives for ratepayers, or a bundling incentive option being considered, they should be noted and the participation forecast adjusted accordingly.
Financial Impacts & Risks	Using preliminary incentive rates identified in the previous phase and participation forecast, the impact on the aggregate administrator budget and the program budget can be determined. This	The Energy Trust of Oregon is mindful of the impact of incentive rates on the market barriers identified during its structured measure and incentive development process. Accordingly, it seeks to properly balance the needs for	Program administrators should undertake the following activities to identify financial impacts:

Model Incentive Rates			
General Principle	Definition	Examples	Identified Best Practice
	can set the stage for incentive adjustments in order to properly balance the incentive rate vs. the identified market barriers and the requirements to adequately deliver the program to meet savings goals. Many jurisdictions' studies weigh the impact of incentive rates on total program budgets.	administration and incentive funding in its programs required to overcome the identified market barriers. NYSERDA conducts financial forecasting as part of their incentive setting process in order to determine the impact on program budgets.	• Determine the impact of incentives on program budgets • Determine the volumetric risk impacts on program budgets • Identify where/how budget constraints may hinder the desired program delivery strategies to overcome customer barriers
Cost Effectiveness Testing	The cost effectiveness of measures, programs and portfolios should be tested to determine whether a modification in incentive or administration expenses is required to deliver the programs in a manner which meets the cost effectiveness standards set by regulators. All jurisdictions studied perform cost effectiveness testing and certain jurisdictions will perform it at the measure level when setting incentives. Typically, the jurisdictions used variants of the TRC and the PAC as the main tests. It is also important to note that many jurisdictions included other benefits aside from avoided capacity and energy when determining avoided costs.	PG&E performs streamlined cost effectiveness testing at every stage of the product development process in order to determine preliminary incentive rates to ensure that the incentive will allow for the proper market transformation goals to be achieved. There is no obligation for every measure to be cost-effective in PG&E's portfolio. The Energy Trust of Oregon measures cost effectiveness at both the measure and portfolio level using the TRC and the UCT. Yet, the Oregon Public Utilities Commission (PUC) has allowed for non-cost effective measures to be included in the portfolio if it meets certain criteria. This has been very beneficial in maintaining market momentum of measures and programs in a market where natural gas wholesale prices have fallen. Measure level testing excludes administration and delivery costs as these can vary greatly based on the go-to-market approach of the program. For incentives that are increasing, NYSERDA conducts cost effectiveness analysis for the TRC and PAC, and as required, presents it to New York PUC.	The following cost effectiveness testing best practices should be adopted by program administrators: • Measure level screening and either program or portfolio-level cost effectiveness testing • The allowance for non-cost effective measures to be included in portfolios should the measure require temporary cost effectiveness relief, should it be an emerging measure which aligns with policy goals or should the measures be targeted for a specific priority sector (e.g., low income) • The use of appropriate cost effectiveness tests for screening and threshold setting • The use of the average or weighted average costs of energy to determine avoided costs

Table 9: Model Incentive Rates

Review of Nova Scotia's Electricity System and Market

NOVA SCOTIA'S ELECTRICITY SYSTEM

In 2015, Nova Scotia had an annual electricity consumption of 10,400 GWh. The residential sector accounts for 45 percent of consumption, the commercial sector uses about 32 percent, and the industrial sector uses 23 percent. Nova Scotia's industrial load has been significantly reduced over the past few years. The loss of industrial load, the effort to bring renewables into the supply mix and increased fuel costs have all contributed to a 70 percent increase in Nova Scotia's retail electricity rate over the past 10 years.

Nova Scotia Power Inc. (NS Power) owns about 95 percent of Nova Scotia's infrastructure for generating and delivery electricity. NS Power is a private corporation (wholly owned by a public company) that is regulated by the UARB. The other five percent is owned by six municipal electric utilities that can generate their own power or purchase it from NS Power or independent power producers.

Nova Scotia is transitioning away from coal supply.[12] The 2014 supply mix was dominated by coal, accounting for 60 percent of generation. Domestic renewables (wind, hydro and tidal) accounted for more than 15 percent, more than 10 percent coming from natural gas and imported renewables at more than five percent. Efficiency and conservation activities currently contribute about eight percent of total generation.

By 2020, the province aims to dramatically reduce the coal contribution to the supply mix to between 20-35 percent, while increasing the domestic renewables share to 27 percent and the imported renewables share to 23 percent. The key themes that Nova Scotians want followed for the electricity system are:

- accountability;
- market competition;
- stable power rates in an accountable and transparent electricity system; and
- support for innovation, but not at any cost.

Provincial legislation also requires that, by 2020, 40 percent of Nova Scotia's electricity supply must come from renewable sources. Similarly, in 2020, the provincial cap on greenhouse gas emissions will be lowered by 25 percent to 7.5 million tonnes in 2020; this will be further reduced to 4.5 million tonnes by 2030.[13]

Nova Scotia is a winter peaking province with a very diverse load. The 2015 peak was just over 2,100 MW. During the shoulder seasons, loads can be as low as 700 MW. Therefore, the system needs to manage variable loads throughout the year, while maintaining price certainty for customers.

Projects such as the Maritime Link, allowing for a direct renewable to retail market, and expanding conservation efforts to offset load growth are critical.

NOVA SCOTIA MARKET CHARACTERISTICS

Nova Scotia has a population of approximately 950,000 people. There are just under 500,000 residential, commercial and industrial electricity accounts for NS Power.

[12] Our Electricity Future: Nova Scotia's Energy Plan 2015-2020, Nova Scotia Department of Energy, Available: http://energy.novascotia.ca/sites/default/files/Our-Electricity-Future.pdf

[13] Our Electricity Future: Nova Scotia's Energy Plan 2015-2020, Nova Scotia Department of Energy, Available: http://energy.novascotia.ca/sites/default/files/Our-Electricity-Future.pdf

Rate Class	Number of Customer Accounts *
Residential	456,991
Small General Business	24,109
General Business	11,349
Large General Business	19
Small Industrial	2,221
Medium Industrial	198
Large Industrial	32
Municipal	8
Total	**494,927**

*This does not include the customer accounts from the six municipal electric utilities.

Table 10: **NS Power Customer Accounts by Rate Class**

The following information was obtained from the Nova Scotia 2015-2040 DSM Potential Study, authored by Navigant Consulting in 2014[14], from information obtained from EfficiencyOne employees and from other industry data sources such as Stats Canada and ElectroFed.

RESIDENTIAL SECTOR

There are more than 390,280 residential households in Nova Scotia.[15] The majority of customers are on flat-billing residential electricity purchase agreements. Only 1,000 customers are on residential time-of-use pricing, which minimizes the ability to include messaging and incentives that reduce peak consumption in the residential sector. Of these homes, 75 percent are single family dwellings, both detached and attached. Residential new construction has been relatively consistent the past 35 years, with each six year period since 1980 contributing an average of 6-8 percent of the current residential housing stock. The average size of the homes is between 1,550-1,765 square feet, with 75 percent of homes being between 1,000 and 3,500 square feet.[14]

The potential study indicated that 51 percent of all installed lamps were incandescent, with LEDs only making up four percent of the installed base.[14] When comparing these stock numbers to 2015 residential sales data for Atlantic Canada, incandescent technology still dominates the market with the largest contribution in A lamps and decorative lamps, and the second largest share in reflector lamps. LEDs sales are increasing, especially in the reflector lamp category, but the total installed base indicates that significant efforts are still required to achieve market transformation in the residential lighting space.

In Nova Scotia, 31 percent of all primary heating systems in homes are electric.[14] The dominant heating technology is fuel oil, with a 46 percent share. Secondary heating systems are found in 59 percent of Nova Scotia's homes, and of these, 32 percent are electric. This leads to an estimate of 225,000 electric heating systems in Nova Scotia, of which 140,000 are primary and 85,000 are secondary.

EfficiencyOne assumes that primary heating systems have 2,750 operating hours, while secondary heating systems are used a variable amount that is less than the primary hours of operation. This leads to a significant opportunity to pursue electricity savings in residential space heating, since substantial savings can be obtained in one home. Additionally, due to the average housing size (leading to lower heating requirements), there are more options for electricity-efficient heating systems.

Nova Scotia homes do not have a large space cooling load. The primary cooling system is an electric fan, while only three percent of homes have central air conditioning, and 18 percent have portable air conditioning units (room or window air

[14] Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study – Navigant Consulting
[15] http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/famil55a-eng.htm

conditioners). Nova Scotia is a winter peaking province, therefore electricity savings targeted at off-peak periods may not help with capacity management. Additionally, space cooling savings usually have higher unit costs ($/kWh) for electricity conservation programs due to the limited hours of operation.

Finally, Nova Scotia homes have a high proportion (61 percent) of electric water heaters. This majority also presents efficiency opportunities for larger savings coming from individual projects.

BUSINESS, NOT-FOR PROFIT AND INSTITUTIONAL SECTOR

The commercial sector accounts for businesses, not-for-profits and institutional customers. In Nova Scotia, there are 37,679 accounts that are represented by the Small Business Advocate. These accounts cover three rate classes (small general business, general business and small industrial). Of the 37,679 accounts, 24,109 are small business accounts. Not all of the 37,679 accounts are eligible for the Small Business Energy Solutions program, where annual consumption has to be less than 350,000 kWh.

In addition to the accounts represented by the Small Business Advocate, there are 19 large general business accounts, 32 large industrial accounts and 238 other business and industrial accounts.

Weekly operating hours for the different commercial customers are split relatively evenly between the different categories:

- 37-48 hours/week (22 percent) – 2100 hours annually;
- 49-72 hours/week (17 percent) – 3100 hours annually;
- 73-96 hours/week (14 percent) – 4400 hours annually;
- 97-120 hours/week (8 percent) – 5700 hours annually;
- 121-168 hours/week (34 percent) – 7500 hours annually and
- Other (5 percent).

Where possible, project applications should try and capture operating hours, either directly or through a proxy. An example of a proxy could be a listing of the assumed hours of operation for a specific business segment or business type. This is included in the incentive level setting recommendations.

Indoor lighting accounts for 60 percent of lighting energy consumption within the commercial sector. Fluorescent technology dominates indoor lighting in the commercial sector with 94 percent of the installed lamp base. The average lamp wattage is 36W, which indicates that the commercial lighting market is close to market transformation from the T12 to the efficient T8. Engineering estimates lead to the conclusion that total conversion of T12 to efficient T8 annual sales would only yield about 15 percent of the annual target. Tubular LEDs have a limited presence in Nova Scotia, so there may be an opportunity to drive future savings. There is also a large opportunity for lighting controls in indoor applications. As indicated, Nova Scotia commercial facilities are typically average, running 12 hours a day, with limited lighting controls penetration (32 percent of indoor lighting is continuous with no control features, while 58 percent only features on/off control).

Unlike the residential sector, the commercial sector features space cooling systems, with 60 percent penetration. The majority of the space cooling systems are direct expansion, meaning there is not a significant chilled water load. There may be an opportunity for rooftop unit equipment upgrades and maintenance incentives to drive savings. Currently, ENS offers financial incentives for rooftop unit equipment upgrades, but not maintenance work.

Finally, unlike the residential sector, the majority of heating systems in commercial buildings are electric, with baseboard heating as the dominant technology.

Efficiency Nova Scotia – Policy, Performance and Programs

Efficiency Nova Scotia Corporation (ENSC) commenced operations in 2010 after the enactment of the *Efficiency Nova Scotia Corporation Act* in 2009. Revisions to the *Public Utilities Act*, introduced through the *Electricity Efficiency and Conservation Restructuring (2014) Act*, pronounced a structural change for energy efficiency and conservation activities in Nova Scotia in 2015.

ENSC ceased to exist as Nova Scotia's DSM provider on January 1, 2015. In its place, the Minister of Energy created and awarded the ENS franchise. The first franchise holder is EfficiencyOne, an organization incorporated on July 8, 2014 under the *Canada Not-for-profit Corporations Act*. EfficiencyOne is a public utility pursuant to the *Public Utilities Act.*

HISTORICAL RESULTS AND COMPARISON TO OTHER JURISDICTIONS

We provide ENSC's historical portfolio savings from 2010-2014 below, along with a unit cost (first year energy savings), scale of relative effort, and a proxy for "residential customer motivation" comparison to the other jurisdictions:

Year	Residential Energy Savings (GWh)	Business, Not for Profit and Institutional Savings (GWh)	Residential Demand Reduction (MW)	Business, Not for Profit and Institutional Demand Reduction (MW)	Fully Allocated Residential Expenditure ($ million)	Fully Allocated Business. Not for Profit and Institutional Expenditure ($ million)	Fully Allocated Enabling Strategies ($ million)
2010	22	60	5.89	9.96	7.49	11.82	3.39
2011	44	98	12.11	16.75	19.71	13.12	2.96
2012	70	88	17.71	16.08	18.74	20.49	4.44
2013	80	84	16.80	17.30	17.68	18.09	3.85
2014	80	71	15.51	11.57	17.35	16.46	3.30
Total	**297.15**	**401.30**	**68.02**	**71.65**	**80.97**	**79.98**	**17.94**

Table 11: **ENS Historical Performance**

Utility/Agency	Unit Cost of Conservation	Annual Energy Savings as % of Retail Sales (2014)	Residential Electricity Rate (2014)
Nova Scotia	$0.25/kWh	1.3%	$0.148/kWh
Ontario (IESO)	$0.25/kWh	1.3%	$0.10-$0.124/kWh
British Columbia (B.C Hydro)	N/A	N/A	$0.10-$0.12/kWh
California (PG&E)*	$0.43/kWh	1%	$0.1625/kWh
Energy Trust of Oregon*	N/A	N/A	$0.11/kWh
New York (ConEd)*	$0.48/kWh	≈1%	$0.2885 cents/kWh
New York (NYSERDA)*	N/A	≈1%	$0.2005/kWh
Vermont*	$0.40/kWh	2%	$0.125-$0.195/kWh
Maine (Efficiency Maine)*	$0.20/kWh (Electric Base) $0.30/kWh (MACE Low Cost) $0.35/kWh (MACE High Cost)	1.6%	$0.1567/kWh
Massachusetts (National Grid)*	$0.46/kWh	2.94%	$0.165-$0.185/kWh

**The dollar amounts for these jurisdictions are quoted in US dollars.*

Table 122: Unit Cost, Energy Savings, and Residential Rate from Different Jurisdictions

As can be seen from Table 12, the portfolio performance achieved by EfficiencyOne and the current energy efficiency targets in Nova Scotia are comparable to the other jurisdictions studied. The numbers support, at a portfolio level, that that there isn't a significant variation in ENS spending, especially with regards to incentive spending, compared to the other jurisdictions.

EFFICIENCY GOALS

As per the *Electricity Efficiency and Conservation Restructuring (2014) Act*, "Nova Scotia Power Incorporated shall undertake cost-effective electricity efficiency and conservation activities that are reasonably available in an effort to reduce costs for its customers."[16]

After the end of the most recent DSM planning process, ENS's 2016-2018 savings targets and budgets are as follows:

Year	Savings (GWh)	Expenditure ($ million)	Unit Cost ($/kWh)
2016	133.1	$33.21	$0.25/kWh
2017	136.5	$34.02	$0.25/kWh
2018	136.3	$34.92	$0.26/kWh
Total	405.9	$102.15	$0.25/kWh

Table 133: ENS's Targets and Budgets

[16] *Electricity Efficiency and Conservation Restructuring (2014) Act - http://nslegislature.ca/legc/bills/62nd_1st/1st_read/b041.htm*

From a total consumption perspective, ENS's annual target for 2015 is 1.3 percent of electricity sales for that year, which is comparable to other jurisdictions as seen in Table 12.

POLICY CONSIDERATIONS

ACHIEVABLE POTENTIAL

In 2014, Navigant Consulting conducted an achievable potential study for Nova Scotia, (Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study)[17]. It indicated that the achievable potential and required expenditure for 2016, 2017, and 2018 were as follows:

Year	Annual Savings (GWh)	Expenditure ($ million)	Unit Cost ($/kWh)
2016	139.9	$50.5	$0.36/kWh
2017	141.7	$50.0	$0.35/kWh
2018	136.2	$52.4	$0.38/kWh
Total	417.8	$152.9	$0.37/kWh

Table 144: **Nova Scotia Achievable Potential Summary**

The numbers presented are for the base scenario, where the incentives do not change over time. This suggests that ENS's current savings targets are almost 100 percent of the achievable potential. However, the approved budget by the UARB is only between 50-70 percent of the forecasted required budget set forth in the Achievable Potential Study, depending on the year and the scenario.

This leads to the conclusion that ENS is running its portfolio efficiently, and is optimizing its savings for expenditure. The best practices identified earlier will be applied to ENS's portfolio and specific improvements will be suggested, but it should be clear that quantitatively, the performance of the portfolio from an expenditure to annual savings basis is good compared to the available achievable potential. The historical performance has also been good compared to other jurisdictions as shown in the historical results analysis above.

CLEAResult used the data from the *Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study* to provide background and context in terms of understanding the housing, commercial building and equipment stock in Nova Scotia, and the achievable savings potential through the current programs.

COST EFFECTIVENESS AND AVOIDED COSTS

At the portfolio level, cost effectiveness is guaranteed since the combination of savings targets and budget is lower than the cost effectiveness threshold (provided that the persistence of the energy savings is equal to or better than the forecast). However, during each program planning phase, ENS internally sets a cutoff of a TRC of 1.0 for each program. The TRC benefits include any potential impacts from wood or water consumption or savings (which are about 1 percent of the DSM Resource Plan portfolio benefits). The PAC is used for informational purposes, but is not part of the review protocol.

All program measures are tested at the measure level for TRC, and non-compliant measures can be removed. Occasionally, measures that do not pass the measure level TRC are included in programs due to other considerations, such as market transformation or program delivery strategy. Similar strategies are applied to non-cost effective measures in other jurisdictions to maintain market momentum and adapt to sudden changes in avoided costs (e.g., Energy Trust of Oregon). At the measure level, program administration costs are included in the TRC screening.

[17] Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study – Navigant Consulting

The program administration costs are allocated based on a unit program administration costs/kWh savings adder. This is an interesting approach since, for TRC screening, the only cost parameter that ENS controls is the program administration costs (incentives are not directly included in the TRC). Other jurisdictions have applied different approaches for measure level testing, choosing to exclude administration costs as these can vary greatly depending on the maturity of the measure in the market.

In conducting cost effectiveness screening, ENS uses the Energy Efficiency Resource Assessment Model (EERAM), developed by Navigant. This model is typically targeted for long-term (20-25 years) energy savings potential and planning purposes. It is not used for incentive setting.

Avoided costs are updated every three to four years with the filing of the Integrated Resource Plan (IRP). Nova Scotia Power Inc. provides the avoided costs.

The current methodology has conservation activity competing with the lowest cost of supply. This is different to many other jurisdictions where avoided costs are typically calculated using either the average or marginal cost of supply and potentially other costs, such as renewable standards. Nova Scotia is forecasted to have excess electric generation capacity until 2019. Therefore, current avoided costs for capacity are set at $0/kW for any demand savings occurring up to that time. Because of this, measures and projects that pass the TRC and PAC are only able to claim the benefit of avoided energy costs until 2020. After 2020, they can claim both avoided energy and capacity benefits.

This can be a challenge since momentum through awareness and a continued presence in the market is required for long-term efficiency program success. It is difficult to modify energy efficiency program performance and the measure portfolio (both selection and incentive levels) to adjust for annual variations in the avoided costs. Deployment of specific programs or measures can take advantage of annual variations, but it is difficult to apply this approach to an entire portfolio. Other jurisdictions, such as Oregon, have addressed this issue by providing relief from a cost effectiveness perspective when there needs to be alignment with energy efficiency policy and portfolio savings goals.

The avoided costs of energy are the same across all time periods in the year. This means that the benefits derived from energy savings do not depend on the time that the energy savings occur. There is not a premium for measures that contribute energy savings coincidently with peak periods, outside of avoided capacity savings during system peak.

CLEAResult understands that ENS is currently investigating the opportunity to recognize local avoided costs, and to consider discount and premium zones for electricity conservation. This position will be considered in any incentive methodology recommendations.

OTHER CONSIDERATIONS

Through the most recent program evaluation process, ENS has identified that some educational initiatives are incurring savings attribution issues, and have received tentative disallowance. This specifically was the case for the Home Energy Reports (HER) program. In the future, this may lead to additional difficultly minimizing expenditure by moving funding from financial incentives to educational incentives. This issue must be considered if an eventual goal is to ultimately eliminate financial incentives from programs, and reach market transformation of an energy efficient culture.

Finally, ENS does not use dual baselines in their energy savings estimates for measures for operational tracking. Dual baselines involve assuming a set baseline for a number of years, and then another baseline for the remaining number of years assumed in the energy savings persistence. Instead, they use an average wattage/consumption approach. This may be acceptable for determining annual energy savings, but may present challenges when determining lifetime energy savings. An approach should be considered for tracking lifetime energy savings through program management.

EFFICIENCY NOVA SCOTIA'S PROGRAM PORTFOLIO

The following table contains a summary of ENS's current programs, target market and incentive structure.

Commercial customers are defined as businesses, not-for-profits and institutional customers.

Current Programs

Mass Market programs (programs that do not target individual customers specifically) cover all types of program scenarios. For example, a retail program can cover all four of these scenarios (New Purchase/Installation, Replacement on Failure, Early Replacement and Replacement after Assumed Failure), and customers are not accepted into the program or declined from participating based on what category they fit in. In Table 15, CLEAResult and EfficiencyOne have outlined the predominant scenarios considered in the program design.

Program Name	Program Offer and Incentive Structure	Type of Program (for CE modelling purposes)
Residential Profile	An online assessment tool is provided for customers to enter information about their home and receive energy savings tips and information regarding options and incentives. The online assessment tool is provided free of charge. The expenditure for this effort is not included as an incentive, and savings are not attributed to its use.	Education and Awareness (no attributable savings)
Instant Savings	Residential customers receive instant discounts at the point of purchase for qualifying products at participating retailers. Incentives are offered on lighting and lighting control products, power bars, outdoor timers, programmable thermostats, outdoor clothesline kits and qualifying refrigerators and clothes washers. A delivery agent is involved to coordinate retailer efforts, provide the required training and manage compliance issues.	Replacement on Failure New Purchase/Installation Early Replacement
Appliance Retirement	Residential customers receive a financial incentive for the old equipment that is being provided to the program, free equipment pickup, and environmentally friendly decommissioning.	Early Retirement Early Replacement
Home Energy Assessment	Residential customers that are electrically heated receive a subsidized home energy assessment ($99 to the customer) which provides recommendations for energy efficiency upgrades with costs, savings and incentive options. The energy assessment is conducted by service organizations that are procured by EfficiencyOne. As desired, customers complete the upgrades, have a follow-up assessment to evaluate installed projects and savings, and confirm the appropriate incentive.	Early Replacement New Purchase/Installation
Residential Direct Install and Rental Properties and Condos	Residential customers receive products directly installed at no cost by qualified partners. These products include lighting measures, domestic water heating measures (where electric water heating) and power strips.	Early Replacement New Purchase/Installation
Green Heat	Residential customers that are electrically heated receive incentives or low cost financing for the installation of qualifying heating technologies. Pre-approval for installation must be granted for rebate eligibility or low cost financing. A final application/documentation review is required after installation to confirm the rebate payment or access to low cost financing.	New Purchase/Installation Early Replacement
New Home Construction	Residential customers that are planning to build electrically heated homes can have a Certified Energy Advisor review the building plans, and provide customized recommendations to improve the energy efficiency of the design. The review by the Certified Energy Advisor	New Purchase/Installation

Program Name	Program Offer and Incentive Structure	Type of Program (for CE modelling purposes)
	costs $99, and based on changes to the design, the customer can receive up to $2,000 in rebates. The rebate is paid after the Certified Energy Advisor conducts a follow-up assessment to evaluate the new energy performance of the home, either through the ENERGY STAR®, EnerGuide, or R2000 rating systems.	
Business Energy Rebates	This incentive offer for commercial and industrial customers is offered through a midstream with participating distributors, or downstream using an application process. Qualifying equipment is provided with a prescriptive incentive. Alternatively, qualifying customers are offered interest-free financing for 24 months instead of the prescriptive incentives.	Replacement on Failure New Purchase/Installation Early Replacement
Small Business Energy Solutions (SBES)	Qualifying small commercial and industrial customers (with an annual consumption under 350,000 kWh) receive qualifying products installed with up to 60 percent of the costs covered. Customers are also offered interest-free financing for 24 months in addition to the rebates.	Early Replacement New Purchase/Installation
Custom	Commercial, institutional and industrial customers are eligible to apply to the Custom Program for measures or projects that do not fit under a prescriptive project stream. Scoping and/or Feasibility studies have to be conducted before the project is approved to proceed. The incentive is calculated based on multiple factors (total cost, cost per kWh, simple payback and percentage of project cost), and is individually negotiated with each customer. Interest-free, multi-year financing is available for the remaining project costs. There is also a compressed air-focused component where customers can have a no-cost targeted study performed to investigate compressed air energy efficiency opportunities. Additionally, there is a leak fixing incentive. For larger commercial and industrial customers, recommissioning specialists will review the building's original operating documents, equipment, temperature settings and scheduling to ensure everything is working properly and set for optimal efficiency. The specialists provide the customers with a report outlining the enhancements made, and other areas for energy savings. The work conducted by the recommissioning specialists is partially covered (depending on cost, payback, and unit cost), up to a maximum of $25,000 per building. Customers can access other programs for the other energy savings opportunities. For commercial and industrial customers planning a new build, a building expansion or a major renovation, the program provides assistance with design through energy modeling assistance, fully covered up to $15,000. Customers can apply for prescriptive incentives for qualifying equipment, as well as access to additional incentives or interest-free, multi-year financing for the remaining incremental measure costs.	*Dependent on Project Parameters*
Energy Management Information Systems (EMIS)	For larger commercial and industrial customers, the EMIS program offers access to a performance management system to monitor and analyze energy usage in the facility. The program provides funding and facilitates the installation, training for, and evaluation of the installed equipment. The decision to maintain the system at the customer's facility is made annually.	New Purchase/Installation

Program Name	Program Offer and Incentive Structure	Type of Program (for CE modelling purposes)
Strategic Energy Management (SEM)	For larger commercial and industrial customers, SEM provides a comprehensive approach to energy management that results in sustainable energy and cost savings over the long-term. ENS provides support for implementing the SEM approach by facilitating energy mapping, monitoring and reporting, employee training, and support for employee engagement activities.	New Purchase/Installation

Table 15: **ENS Program Overview**

Low Income Program Plans

ENS's DSM portfolio currently does not feature an electricity DSM program exclusively directed towards the low income sector. However, there are plans for an energy efficiency incentive offering to this sector. CLEAResult has included a summary of the plans below:

> *Market analysis performed by Efficiency Nova Scotia in 2015 identified an opportunity to evaluate and begin development of a pilot program specifically designed to support efficiency improvements in low income multi-unit buildings. The pilot program would deliver building-wide upgrades that reduce electricity consumption in eligible properties. It is expected that the pilot program would provide 100 percent coverage for an energy audit to identify all opportunities. Additional rebates would be available for measures such as: insulation; air sealing; efficient heating systems; heat recovery systems; pipe insulation; sensors and timers; and Heating, Ventilation and Air Conditioning (HVAC) controls.*
>
> *The pilot program delivery is intended to be modeled after the SBES delivery model and unit cost, and will support all providers of affordable rental housing. The pilot aims to remove the 350,000 kWh cap currently established under SBES so that larger, affordable housing properties are not arbitrarily neglected. Due to the limited budget of the pilot, considerations on funding caps will also be developed at both the owner and project levels (i.e. restricting the amount of funding for any one landlord or project).*[18]

Programs Studied in Recommendations

The following table contains an analysis of the barriers and the associated incentive strategy for the four investigated programs.

[18] Email Communication from EfficiencyOne Program Management Staff – May 25, 2016

Program	Identified Barriers	Incentive Strategy
Instant Savings	1) Residential customers worry about upfront costs. For example, LED penetration, despite dropping upfront costs from 2013-2015, LEDs still account for less than 10 percent of A Lamp sales due to their retail price compared to incandescent lamps. Appliances are large budget items, and features are prioritized over efficiency. 2) Residential customers need simplicity; submitting incentive applications is a barrier to participation. 3) Retailers and their employees show varying degrees of awareness, engagement and knowledge of the program.	1) Residential customers receive incentives at the point of sale. The incentives are typically between 15-50 percent, but may be higher for some measures. 2) Residential customers receive instant discounts at the point of purchase for qualifying products at participating retailers. Receiving the discount at the point of purchase prevents the need for an incentive application. 3) A delivery agent is involved to coordinate retailer efforts, provide the required training and manage compliance issues. Additionally, strategies, tactics and campaigns are used to promote participation through improving customer awareness and education, while also conducting retailer training to improve engagement and program knowledge.
Home Energy Assessment	1) Residential customers lack knowledge about the potential for savings in their homes. 2) Residential customers worry about upfront costs.	1) Residential customers receive a subsidized energy assessment to learn about the energy efficiency opportunities in their homes, and the potential costs, savings, and incentive options. They also have access to a personal energy planning service for additional support. 2) Residential customers receive incentives for installing eligible measures. The incentive is typically 15-25 percent of the project costs.
Business Energy Rebates	1) For efficiency projects, commercial and industrial customers are concerned about upfront capital. 2) Commercial and industrial customers have a lack of education about energy efficient projects. 3) Commercial and industrial customers show an unwillingness to change their practices.	1) Commercial and industrial customers receive prescriptive incentives for purchased products. Incentives are capped at 50 percent of project costs, but usually do not reach this amount. 2) Through the midstream application, the distributors are engaged to educate the contractors. The contractors are one of the major points of influence for customers, and through this educational effort, awareness for energy efficiency grows. 3) Through the midstream application, in addition to the contractor education benefit that will pass down to the customers, the distributors are encouraged to stock more efficient products, forcing the market to change in terms of the options available.
Custom Program	1) Commercial and industrial customers have measures that are not included in the prescriptive programs. This includes the new construction, recommissioning and compressed air project streams that fall within the Custom Program.	1) The program allows projects that do not fit into the prescriptive incentive programs, provided they meet eligibility criteria, and undergo studies to verify their energy savings and costs.

Table 16: Barriers and Incentive Strategy for EfficiencyOne Programs Studied

Incentive Setting Methodology Analysis and Recommendations

CLEAResult's analysis and recommendations for incentive level setting methodology will focus on the following areas:

1. General Principles;
2. Formal and Documented Incentive Setting Process;
3. Program-Specific Recommendations;
   - Instant Savings Program;
   - Custom Program;
   - Business Energy Rebates Program; and
   - Home Energy Assessment Program.
4. Complementary Excel Tool for Review Protocol Considerations;
5. Program Financial Simulation;
   - Instant Savings Program; and
   - Custom Program.

SUMMARY OF RECOMMENDATIONS

1. **It is recommended that EfficiencyOne consider all of the general principles for incorporation into an incentive setting process.**

   CLEAResult has provided a documented, incentive setting process (that incorporates these general principles) that can be leveraged by EfficiencyOne, along with the required template documents and tools.

2. **In addition, through recommending the general principles be followed in any incentive setting methodology that EfficiencyOne implements, there are several supporting requirements:**

   a) Ensure assumptions for residential and commercial LEDs, residential HVAC technology, commercial fluorescent technology and commercial Variable Frequency Drive (VFD) technology are kept up to date by conducting customer and technology research.

   b) Further support technology research by implementing a TRM approach. The energy savings and cost effectiveness metrics of the measures provide several reference points for setting incentive levels.

   c) Develop a consolidated calculator that can conduct the analysis that supports the incentive-level setting process. The calculator should have the following functionality:

      i. Capture and store measure-level information obtained from the recommended research activities and TRM process
      ii. Perform short-term program design or incentive-level cost effectiveness screening
      iii. Integrate the review protocol that has been provided in the Excel-based tool.

3. **Through adopting an incentive setting methodology that follows the general principles, conduct a program financial simulation of all of the current incentives in the programs to evaluate their current levels.**

GENERAL PRINCIPLES FOR INCENTIVE RATE SETTING

Based on CLEAResult's experience and research on best practices, it is recommended that any incentive level setting methodology should include the following general principles to understand:

1. Customer motivations and barriers for participation;
2. Technology savings, price and market penetration;
3. Supply chain and service provider considerations;
4. Financial impacts; and
5. Jurisdictional benchmarking (for new incentives).

CUSTOMER MOTIVATIONS AND BARRIERS

As discussed, understanding customer motivations and barriers to participation are important. A key component of the customer research is understanding how customers view costs associated with the efficient option; this will allow the appropriate Customer Cost parameter to be identified, and the incentive (and supporting education efforts) to be designed with the customer's perspective and their perceived value in mind.

This customer research can be performed in numerous ways; it is often done through surveys of both randomly selected participants and non-participants, for specific research projects, ongoing program management activity or program evaluations.

For incentive setting and general program design purposes, there are two types of market research that can be used to provide comprehensive incentive modelling assistance.

1. Price Sensitivity Research
2. Conjoint Analysis

Price sensitivity research focuses solely on how customer motivation to purchase changes with the price point of a product or service. It does not analyze customer motivation for any other factors. Conjoint analysis, on the other hand, looks at a multiple-variable analysis to attempt to determine customer motivation to purchase for different combination of variables. Price is often one of the variables for conjoint analysis when it is applied to incentive setting.

These types of research can be expensive, and it is advised that they are only used for high-value incentive expenditure for individual measures (greater than $400,000 in annual expenditure over multiple (2+) years). The $400,000 value was obtained from a high-level evaluation of ENS's current individual incentive expenditure compared to the total portfolio expenditure.

Price Sensitivity Research

Price sensitivity is usually defined as the affect the price for a product or service has on the consumers' motivation to purchase it. For incentive setting in energy efficiency and conservation programs, it is important to understand what is required to move the market and encourage participation, while also ensuring the ratepayer's interests are protected.

Price sensitivity is also known in economic terms as the price elasticity of demand. It is important to note that consumers are not a homogenous group for most energy efficiency purchasing decisions, so it is practically impossible to get an exact answer for optimal pricing, and the associated price elasticity. However, by conducting this research, indications of general accuracy can be obtained, which help support other analyses and historical experience.

A popular price sensitivity analysis is Van Westendorp's Price Sensitivity Meter.[19] A wide variety of researchers prefer this technique since it can apply to multiple industries and it is simple to understand. The technique involves asking four price-related questions, which are then evaluated as a series of cumulative distributions, a distribution for each question. The four questions are:

1. At what price would you consider the product to be so expensive that you would not consider buying it? (Too Expensive)
2. At what price would you consider the product to be priced so low that you would feel the quality could not be very good? (Too Cheap)

[19] Roll et al. Innovative Approaches to Analyzing the Price Sensitivity Meter: Results of an International Comparative Study - https://www.researchgate.net/profile/Heidi_Korhonen3/publication/48330473_Determinants_to_Service_Innovation_Success_an_Organizational_Orientation_Perspective/links/0046353c383c558013000000.pdf#page=182

3. At what price would you consider the product to be starting to get expensive, so that it is not out of the question, but you would have to give some thought to buying it? (Expensive)
4. At what price would you consider the product to be a bargain – a great buy for the money? (Cheap)

Since consumers are not a homogenous group, the distributions are needed with a significant sample size. The intersection of the cumulative distribution curves indicate what could be acceptable pricing levels for consumers for a particular product or service. For example, the intersections of the curves for Too Cheap and Cheap (questions (2) and (4)) predict the price of marginal cheapness, and can set the lower boundary of an acceptable price range for consumers. Similarly, the intersections of the curves for Too Expensive and Expensive (questions (1) and (3)) predict the price of marginal expensiveness, and can set the upper boundary of an acceptable price range for consumers.

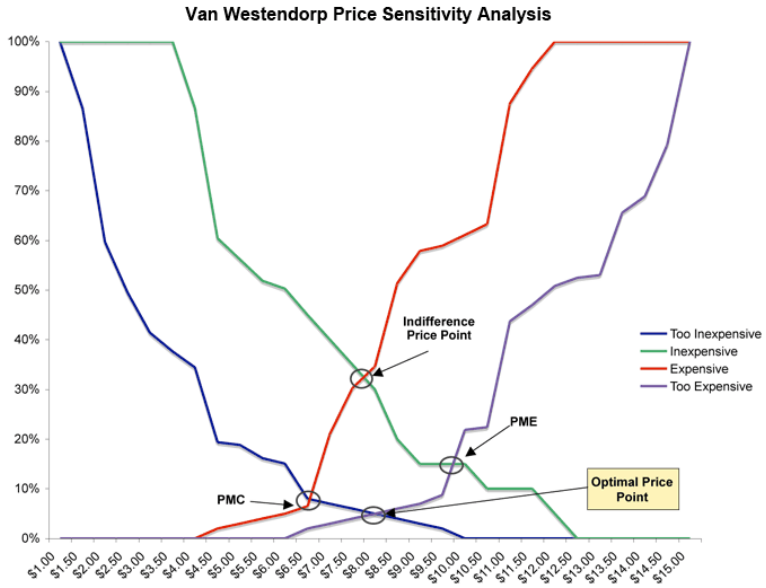


Figure 8: Van Westerndorp's Price Sensitivity Meter[20]

While this analysis is not exact, it provides a useful reference point for setting incentives at one point in time. The Price of Marginal Expensiveness (PME) establishes the upper boundary of acceptable consumer pricing, while the Price of Marginal Cheapness/Inexpensiveness (PMI) establishes the lower boundary.

As the technology and consumer motivations for purchase evolve, the cumulative distribution curves will change, accordingly.

The Van Westerndorp Prince Sensitivity Meter is just one of many options for understanding price sensitivity and consumer reaction to pricing. There are several other price sensitivity options available in the market, some which are similar, and others which are based on completely different methodologies.

CLEAResult does not recommend any particular type of price sensitivity research; instead the broader recommendation is that price sensitivity research should be performed where appropriate, especially for measures that result in large amounts of incentive spending.

Conjoint Analysis

Conjoint analysis can be used to evaluate how individual attributes contribute to consumers' value of a product or service. With many efficiency programs and incentive offers, there can be multiple benefits to the consumer including financial, educational and convenience. All of these benefits increase consumer value, and it may be possible to understand how much of a customer's

[20] https://rmsbunkerblog.wordpress.com/2010/09/09/understanding-the-van-westendorp-pricing-model-market-research-in-central-ny-syracuse-upstate-new_york-surveys/

value is financially driven. If this can be understood, there is a platform to understand what should be an acceptable incentive level.

Conjoint analysis is based on asking consumers to make a series of trade-offs regarding individual product or service attributes. When these trade-offs are analyzed, the relative importance of each benefit can be observed. The trade-offs are usually conducted based on a ranking or rating system that categorizes individual benefits. To better understand the data, consumers should be segmented as much as possible, so that the analysis can be conducted by different consumer segments.

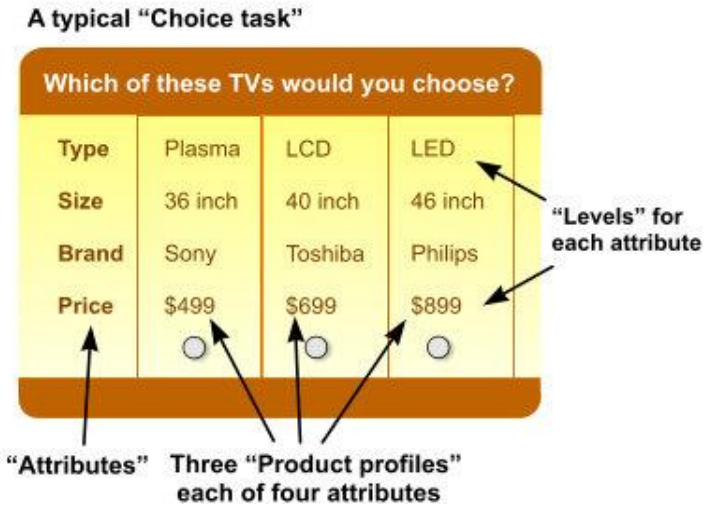


Figure 9: Example of Conjoint Analysis Choice Task[21]

CLEAResult recommends using both Price Sensitivity Research and Conjoint Analysis for individual measure incentives but only for incentive expenditure over $400,000 annually over multiple (2+) years. Otherwise, it is not needed to have research of this level of sophistication.

EfficiencyOne already conducts a lot of the customer (and technology) research required for the incentive level setting process. In evaluating future research requirements, it is advisable that EfficiencyOne review its currently available research, compare it to the documentation requirements in the proposed incentive level setting process, and identify if additional efforts are required. In many cases, the existing research efforts can be leveraged for both customer and technology research.

TECHNOLOGY RESEARCH

Technology research can provide both the basis for the value of the incentive investment through understanding the energy savings and it can provide insight into how often the incentive should be reviewed. It is very important to maintain a continued understanding of the following parameters for incentivized measures:

- Efficient Technology Name;
- Efficient Technology Description;
- Efficient Technology Wattage (if available);
- Efficient Technology Penetration Estimate;
- Forecast Efficient Technology Penetration Estimate (in 1 year);
- Efficient Technology Retail Price;
- Forecast Efficient Technology Retail Price (in 1 year);
- Sector;
- Customer;

[21] http://www.dobney.com/Conjoint/Conjoint_analysis.htm

- Application(s);
- Operating Hours;
- Base Case Technology Name(s);
- Base Case Technology Description(s);
- Base Case Technology Penetration(s);
- Forecast Base Case Technology Penetration(s) (in 1 year);
- Forecast Base Case Technology Retail Price(s) (in 1 year);
- Annual Operating Costs
- Annual Maintenance Costs
- Current Incremental Equipment Cost;
- Forecast Incremental Equipment Cost (in 1 year);
- Energy Savings;
- Expected Energy Savings Persistence;
- Any Program Dependent Parameters (*Should be clearly identified*);
    - Net-to-Gross (NTG) Ratio
- Measure-level TRC and PAC results (*can include adders for overhead delivery costs as required*)
- Participant Cost test results
- Incentive screening threshold in terms of cost to the customer (discussed in financial impact analysis);
- Incentive screening threshold in terms of the program budget (discussed in financial impact analysis); and
- Maximum incentive in terms of cost effectiveness (discussed in financial impact analysis).

Understanding these parameters provides another analysis point for setting incentive levels. For example, if the market penetration of the efficient technology is estimated to be higher than 50 percent, it may be time to consider reducing or eliminating the associated incentive. The above analysis is often performed through a measure assumptions review or TRM update process.

Through the TRM process and from Program Evaluations, this information for prescriptive measures can be reviewed and updated annually or bi-annually as required. During these review, all parameters listed can be updated accordingly.

SUPPLY CHAIN AND SERVICE PROVIDER RESEARCH

The supply chain and service providers should be engaged to support the customer and technology research efforts. It may be difficult to directly contact customers and technology manufacturers to conduct customer and technology research. The supply chain may be able to facilitate the research activities by providing their contacts, and hosting research events.

Additionally, it can be difficult to get firsthand information about customer motivations, price elasticity and the parameters associated with technology. In these situations, it is important to involve the supply chain to obtain additional insight. Also, the supply chain can provide another point of reference for incentive setting analyses by providing reference data (sales, shipments, installations etc.), as well as offering their insight for whether the incentive is appropriate, and if it will motivate customers as desired.

Finally, discussions with the supply chain and service providers, along with other stakeholders, can identify other barriers that the incentives and the broader program design and program delivery strategy must overcome. For example, even if an incentive is extremely financially lucrative for customers, it may be administratively burdensome for the supply chain to apply on behalf of customers due to the program delivery strategy; in such a situation, increasing or decreasing incentive levels may not have an impact, unless the application barrier is overcome.

Having regular interactions with the supply chain and service providers is important for incentive setting activities, and for broader program design and management. Many jurisdictions feature standing panels and/or scheduled discussions with the supply chain, service providers and key stakeholders to obtain this insight.

FINANCIAL IMPACT ANALYSIS

Any incentive setting exercise needs to incorporate the financial impacts into the analysis. It is important to understand how changes in incentives could affect the financial performance of a program.

There are six main components to understanding the financial impact of changing incentive levels.

1. **What is the current incentive, forecasted participation and forecasted incentive expenditure?**
2. **What is the market penetration?**

The incentive thresholds discussed in Figure 5 and Figure 10 can be used to provide three points of reference for the incentive setting process.

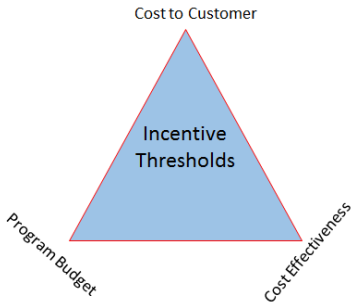


Figure 10: Incentive Thresholds used in Financial Impact Analysis

3. **What is the acceptable incentive threshold in terms of Customer Cost?**

With respect to Customer Cost, there may be an acceptable incentive level threshold that is based on the retail price, project cost, Incremental Equipment Cost or project payback. In every case, incentive amounts have a suggested limit of 100% of Incremental Equipment Cost. This limit can be exceeded, but should be justified by the Program Administrator. For early replacement projects, the RULDICM should be used in place of the Incremental Equipment Cost.

The appropriate basis for the Customer Cost threshold should be informed by conducting the customer research, and understanding what customers think about when making purchase decisions. Based on CLEAResult's program design experience, we have provided a suggested basis for the Customer Cost incentive threshold in Table 17 below. However, each individual program design with its' associated go-to-market, promotion and cost effectiveness approach is unique.
For certain programs, this threshold is often set at 50-70 percent of retail price or project costs, or a minimum of a one year payback period. This does not mean the incentive should be 50-70 percent of the retail price or project costs or that projects should have a minimum of one year payback. These are suggested upper limits. **In some cases, it may be required to exceed the Suggested Upper Limit. These values are guidelines only, and should not be implemented as a hard limit or cap.** In the majority of cases, incentives will be at or below the upper limit.

There may be an acceptable compensation level threshold in terms of cost to the customer that is based on the retail price, Incremental Equipment Cost or simple payback. The threshold is defined for design purposes, and is not a target; it serves as a ceiling.

Customer and Decision	Basis for Customer Cost Incentive Threshold	
	Suggested Basis	Suggested Upper Limit
Low Income Customer, Direct Install Model	Project Cost	100%
Residential Customer, Small Purchase at Retailer	Retail Price, Incremental Equipment Cost	50%, 100%
Residential Customer, Direct Install	Project Cost	100%

Customer and Decision	Basis for Customer Cost Incentive Threshold	
	Suggested Basis	Suggested Upper Limit
Residential Customer, Large Capital Equipment Purchase	Incremental Equipment Cost	100%
Residential Customer, Large Purchase	Incremental Equipment Cost	100%
Commercial and Industrial Small Business Customer, Direct Install	Project Cost	70%-100%
Commercial and Industrial Customer, Small Purchase at Distributor	Retail Price, Incremental Equipment Cost	50%, 100%
Commercial and Industrial Customer, Large Capital Equipment Purchase	Incremental Equipment Cost, Payback	100%, ≥ 1 Year
Commercial and Industrial Customer, Large Purchase	Incremental Equipment Cost, Payback	100%, ≥ 1 Year

Table 17: Basis for Customer Cost Incentive Threshold

Where more than one suggested basis is recommended, the corresponding upper limits are listed in the same order as the suggested basis

4. What is the acceptable incentive threshold in terms of program budget?

With respect to program budgets, there may be an acceptable incentive level threshold that is based on total expenditure or unit costs. For certain programs, this threshold is often set at a maximum incentive for a project, or on some kind of unit cost parameter such as $/kWh. Recommendations for a Suggested Upper Limit should be based on the forecasted program expenditure net of any expected program administration costs. It should be emphasized that budget considerations can set ceilings for incentives, but they shouldn't be the driver for the amount of the proposed incentive; understanding the Customer Cost is always the priority.

Customer and Decision	Basis for Program Budget Incentive Threshold	
	Basis	Suggested Upper Limit
Low Income Customer, Direct Install Model	$/kWh	$1.20/kWh
Residential Customer, Small Purchase at Retailer	$/kWh	$0.50/kWh
Residential Customer, Direct Install	$/kWh	$0.75/kWh
Residential Customer, Large Capital Equipment Purchase	$/kWh	$0.50/kWh
Residential Customer, Large Purchase	$/kWh	$0.50/kWh

Customer and Decision	Basis for Program Budget Incentive Threshold	
	Basis	Suggested Upper Limit
Commercial and Industrial Small Business Customer, Direct Install	$/kWh, Total Incentive	$0.75/kWh
Commercial Customer, Small Purchase at Distributor	$/kWh	$0.25/kWh
Commercial Customer, Large Capital Equipment Purchase	$/kWh, Total Incentive	$0.25/kWh, $500,000
Commercial Customer, Large Purchase	$/kWh, Total Incentive	$0.25/kWh, $500,000

Table 18: Basis for Program Budget Incentive Threshold

Where more than one suggested basis is recommended, the corresponding upper limits are listed in the same order as the suggested basis

5. What is the acceptable incentive threshold in terms of cost effectiveness?

With respect to cost effectiveness, there may be an acceptable incentive level threshold that is based on measure, program or portfolio cost effectiveness targets for the PAC. Suggestions for an upper limit could be based on the forecasted PAC benefits net of any expected program administration costs. This approach is similar to using a lifetime energy savings approach. Lifetime energy savings will have an associated cost effectiveness benefit, and as long as spending is under that amount, the cost effectiveness is not threatened. The lifetime energy savings approach won't include the capacity benefits that the cost effectiveness approach includes in the calculation.

It should be emphasized that cost effectiveness considerations can set ceilings for incentives, but they shouldn't be the driver for the amount of the proposed incentive; understanding the Customer Cost is always the priority.

It is recommended that EfficiencyOne develop a consolidated calculator, where one of the functionality elements is to be able to determine the individual cost effectiveness incentive level thresholds for each measure. The data points and functionality needed to build an appropriate consolidated calculator are listed in Appendix B.

Substantiation for Upper Limits

The values for the upper limits have been recommended from the jurisdictional studies and CLEAResult's experience from program design and incentive setting activities. The concept of setting Upper Limits for incentive levels is a relatively new practice, and there is limited documentation.

From CLEAResult's experience working with retailers and distributors, customers find 50% discounts enticing when making small purchases; as such, it is suggested that 50% be the upper limit for these kinds of purchases. Traditionally, small business direct install programs across North America typically include 100% of the project cost covered, but a new trend has been to include an element of cost-sharing. As such, CLEAResult has included a suggested upper limit of 70-100% for this specific type of incentive/program combination to account for this new trend in cost-sharing.

The following is a selection of jurisdictional evidence that support the concept of incentive level thresholds and suggestions for upper limits. The evidence is not intended to be comprehensive, but has been included to demonstrate there is precedent for these concepts in the energy efficiency world.

It should be noted that the project methodology did not involve a detailed review of Nova Scotia's market and customers (i.e. we did not follow the five principles of incentive setting ourselves) to understand what the limits should specifically be. CLEAResult has provided a starting point in the incentive-setting framework. EfficiencyOne has a responsibility for ensuring the effectiveness of these limits going forward – as products/prices/customer value perceptions change, these limits may need to be adjusted. For

example, if the incentives are very often or never exceeding the upper limits, it could be interpreted that as a reason to pursue an update. At a minimum, the upper limits should be reviewed each year.

As mentioned above, the actual incentives should be below the upper limits in almost all situations.

Jurisdiction	Specific Example	Type of Threshold	Incentive Threshold Upper Limit
BC Hydro	During the interview, it was indicated that incentives are typically set at 50-75% of incremental costs.	Cost to Customer	75% of incremental cost
PG&E	During the interview, it was indicated that incentives are set at 75-100% of incremental costs for new measures, and then updated accordingly as the technology matures and market penetration increases. Measures with paybacks greater than 10 years without incentives typically do not receive incentives.	Cost to Customer	100% of incremental cost (for new measures) *Measures with paybacks greater than 10 years without incentives typically do not receive incentives*
NYSERDA	During the interview, it was indicated that incentives for small prescriptive projects are usually capped at 50% of measure/project cost, though exceptions are made for specific markets and measures.	Cost to Customer	50% of Measure/Project Costs
Union Gas	During the interview, it was indicated that incentives traditionally have fallen between 25-35% of the incremental costs	Cost to Customer	35% of incremental cost
Ontario LDCs	In the Retrofit Program, incentive spending is capped at 50% of project costs if the project involves exterior lighting or custom projects, regardless of the individual incentive amounts for other prescriptive measures or the customer incentive calculation. All other prescriptive measures are capped at 100% of the project cost. In the Process and Systems Upgrade Program, incentives for generation projects are capped at 40% of project costs, while incentives for energy efficiency projects are capped at 70% of project costs	Cost to Customer	100% of Project Costs
ETO	During the interview, it was noted that the ETO has an internal guideline whereby a portfolio's maximum Levelized Unit Energy Cost (LUEC) must be approximately 3-3.5 cents/kWh for electricity programs and approximately 50 cents/therm for natural gas programs	Program Budget, Cost Effectiveness	$0.035/kWh LUEC $0.50/therm LUEC

Table 19: Jurisdictional Examples of Upper Limits

6. What is the proposed incentive, forecasted participation and forecasted incentive expenditure?

Ideally, the proposed incentive is supported by the customer and technology research, and is within the incentive screening thresholds identified above. When the proposed incentive and forecasted participation are determined, the total forecasted incentive expenditure can be found, and compared to the current incentive's forecasted incentive expenditure (Component 1). This allows program administrators to understand the macro-level budget impact for any incentive changes. The historical performance would be one of the main factors in determining the forecasted participation.

Beyond using the lifetime energy savings to quantify the overall PAC cost effectiveness benefit of the measure and using it to document the cost effectiveness incentive level threshold, cost effectiveness screening is not being explicitly recommended as a part of the financial impact analysis.

JURISDICTIONAL BENCHMARKING

Jurisdictional benchmarking is not essential for existing incentives. The current program performance, historical experience and recommended research should provide a comprehensive analysis for incentive setting. It is recommended as best practice to check in periodically with other jurisdictions regarding their programs and incentive levels.

For new incentives, jurisdictional benchmarking should be included due to the absence of current program performance and historical experience. It is important to understand what other jurisdictions offer as incentives, and what nuances and factors may affect these incentive levels due to market size, delivery approach and other influences.

GENERAL PORTFOLIO SUMMARY FOR CURRENT AND RECOMMENDED ACTIVITIES

General Principle	Current Activities	Recommended Activities
Understand Customer Motivation and Barriers for Participation	Currently, EfficiencyOne uses four different methods to understand customer motivation and barriers to participation: 1. Market research to assess customer awareness of programs and reasons for participation/non-participation; 2. Annual surveys through program evaluation process; 3. Active program management which involves customer feedback and CSAT/QA surveys; and 4. Specialized research engagements such as program design or achievable potential study.	• EfficiencyOne should continue these current activities. • An annual survey on key customer and technology combinations should be introduced to provide trending data going forward. It is suggested that the following technology portfolios be studied as they show the highest current participation/savings or future potential (key measures): o Residential LED Lighting Technology; o Residential HVAC Technology; o Commercial Fluorescent Lighting Technology; o Commercial LED Lighting Technology; and o Commercial Variable Frequency Drive Technology. • If any measures or technologies could lead to a large annual incentive expenditure (over $400,000 over multiple years), it may be worth conducting some price sensitivity or conjoint analyses. *Since the retail price of electricity has increased 70 percent in the past ten years, it is important to understand customers affordability concerns and enhance their understanding of available options for reducing their electricity bill. This has been indicated as a consideration in Nova Scotia's electricity system planning[22]. A consistent, multi-pronged market research effort to understand customer motivation and barriers can aid in these efforts. Any existing research activities or data sources can be leveraged to support the recommended research efforts.*

[22] Our Electricity Future: Nova Scotia's Energy Plan 2015-2020, Nova Scotia Department of Energy, Available: http://energy.novascotia.ca/sites/default/files/Our-Electricity-Future.pdf

General Principle	Current Activities	Recommended Activities
Understand Technology Savings, Price and Market Penetration	EfficiencyOne currently understands technology savings, price and market penetration through three different avenues: 1. Annual review through program evaluation process; 2. Specialized research engagements for program design; and 3. Collecting cost/price information, where possible, through program delivery.	• EfficiencyOne's ability to collect cost/price information through program delivery and account management activities should be commended and continued. • EfficiencyOne should continue these current activities. • EfficiencyOne should introduce a formal measures assumption validation process and summary manual. Many other jurisdictions refer to the manual as the TRM and have formal processes for introducing and updating the assumptions for the measure savings and cost information. ○ The parameters should be supported by appropriate primary or secondary research and calculations and these metrics should be reviewed on a periodic basis to confirm they are still valid. Some of this activity may be covered by the program evaluations. Please refer to the Technology Research section for a list of parameters that CLEAResult recommends including in the research. ○ For LEDs in the residential and commercial sector, the updates should occur annually. ○ The updates should be reviewed by a committee, which consists of technical experts from EfficiencyOne's staff, and at least one external member. All members on the committee should have a technical background, and specifically understand and have experience with quantifying measure energy savings, penetrations and costs. The review process for updates should occur annually, ideally in conjunction with, or adjacent to the program evaluation process, so that the two exercises can be collaborative and leverage research.
Understand Supply Chain and Service Provider Considerations	EfficiencyOne interacts with the supply chain through three different avenues: 1. Active program management which involves supply chain interaction; 2. Annual surveys through program evaluation processes; and 3. Specialized research engagements such as program design or achievable potential study	• EfficiencyOne should maintain the current manner that it uses to engage the different supply chains and service providers. It may be a consideration to develop program-specific standing advisory panels that involve the supply chain and service providers as a value add activity but it is not an essential recommendation.

General Principle	Current Activities	Recommended Activities
Understand Financial Impacts	EfficiencyOne conducts cost effectiveness testing using the TRC test. The TRC is calculated at the measure level to qualify measures, though some measures are included that do not pass the TRC test for strategic considerations. The measure level cost effectiveness screen includes total portfolio administration costs spread using a unit cost approach. The TRC is also used at the program level to screen programs for potential implementation, with the program administration costs included. Ex-post cost effectiveness is not conducted. EfficiencyOne currently tracks the programs' financial impact through individual program management operations. When incentive changes are considered, EfficiencyOne creates a financial forecast of the incentive impact on the program budget and unit costs. EfficiencyOne is implementing a new software-based data management and tracking system to track measure implementations.	• EfficiencyOne should continue understanding the macro-level budget impacts from incentive level changes • EfficiencyOne should determine the three appropriate incentive screening thresholds for each measure, either through the TRM process, or through a different process. • For the software-based data management and tracking system, based on the program delivery structure, there may be options to improve tracking frequency. It is advised that as much granularity as possible should be used for frequency. This granularity will provide insight into potential program or portfolio budget risks before they arise and allow EfficiencyOne to modify program spending accordingly. It is understood that some programs may only be able to track data monthly.

Table 20: General Portfolio Summary Table Recommendations

The priority for ensuring information is updated to account for the four principles is based on the relevance of the research at hand. For example, if EfficiencyOne has recently conducted customer research to understand motivations and barriers to participation, it may not be necessary to re-do the customer research for the specific incentive level setting exercise. It may be of more use to put research resources to another effort.

FORMAL & DOCUMENTED INCENTIVE SETTING PROCESS

It is recommended that ENS use a formal and documented incentive setting process for all incentive setting exercises. This does not necessarily mean that every step of the process needs to be fully completed, or even conducted, but there should be justification and documentation for what was included in the process. The following flow charts illustrate three potential processes to use:

1. Initial Process (applicable to all incentive setting exercises);
2. Existing Incentive Development Process (for existing incentives that are being reviewed); and
3. New Incentive Development Process (for new incentives that are being considered for implementation).

The flow charts do not explicitly list the need to document other incentives that may be available in the market for ratepayers to access. It is important to take the potential availability of these other incentives into consideration in terms of the customer research for reduced barriers, the technology research for the potential in reduced energy savings and demand reduction due to attribution issues, and for the financial impact analysis which includes both the incentive screening thresholds and the participation forecast.

INITIAL PROCESS

The initial process should be followed for the beginning of all incentive setting exercises.

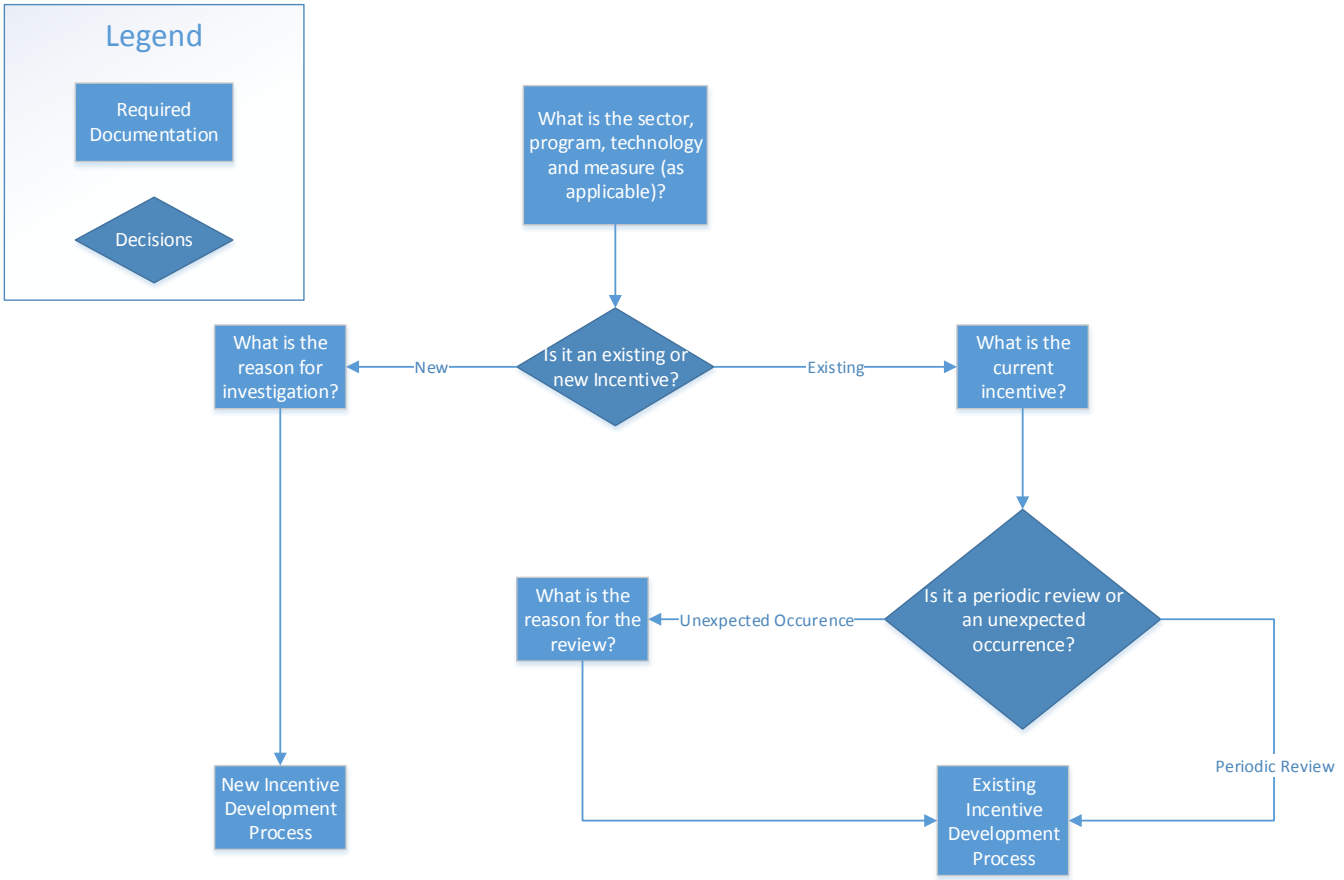


Figure 11: Initial Process for Incentive Setting

EXISTING INCENTIVE DEVELOPMENT PROCESS

The existing incentive development process should be followed for all existing incentives. While it does not necessarily need to be step-wise, all four steps should be covered in the analysis. It would be difficult to complete step (4), without completing steps (1)-(3).

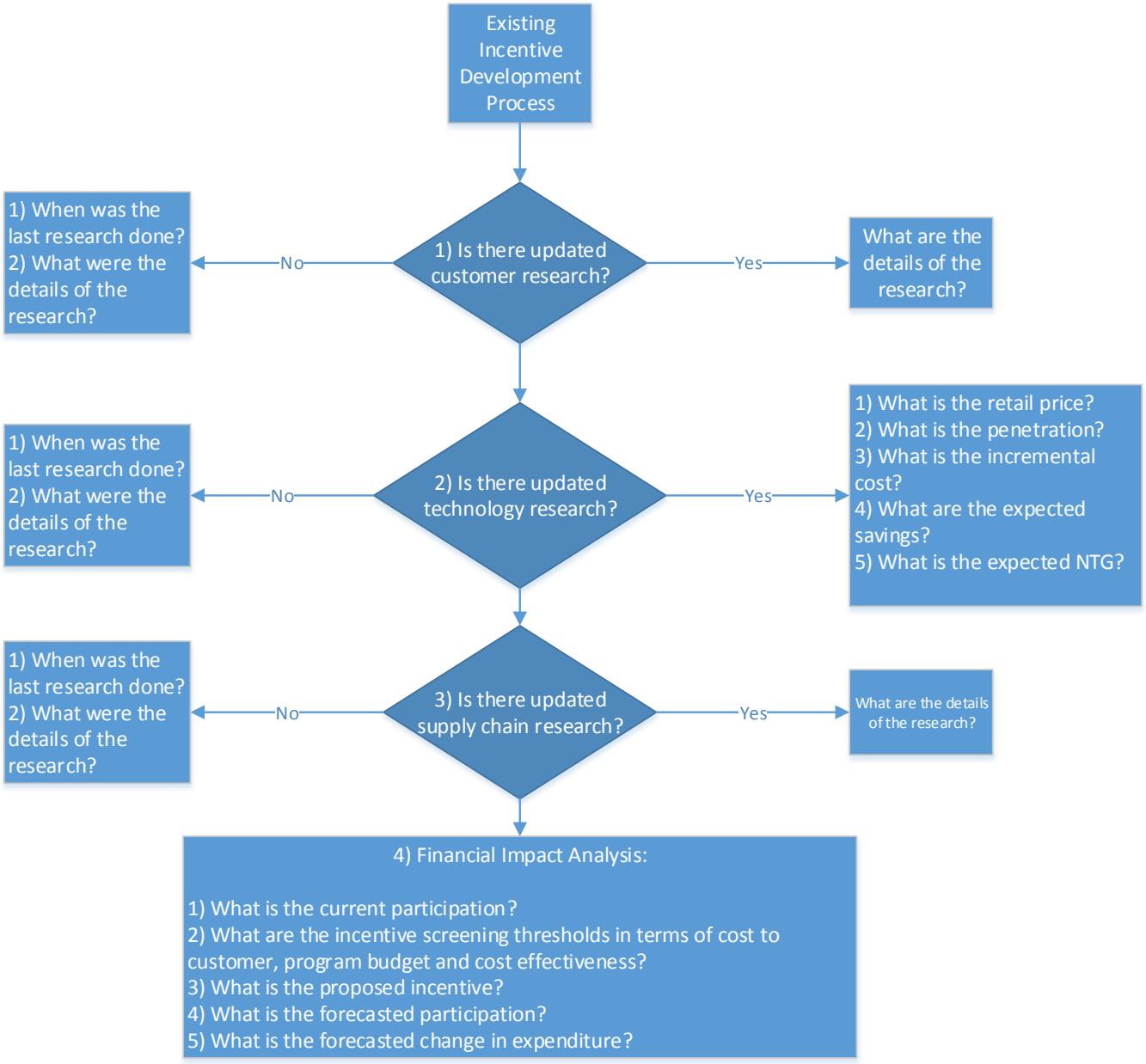


Figure 12: Existing Incentive Development Process

NEW INCENTIVE DEVELOPMENT PROCESS

The new incentive development process should be followed for all new incentives. While it does not necessarily need to be step-wise, all five steps should be covered in the analysis. It would be difficult to complete step (5), without completing steps (1)-(3).

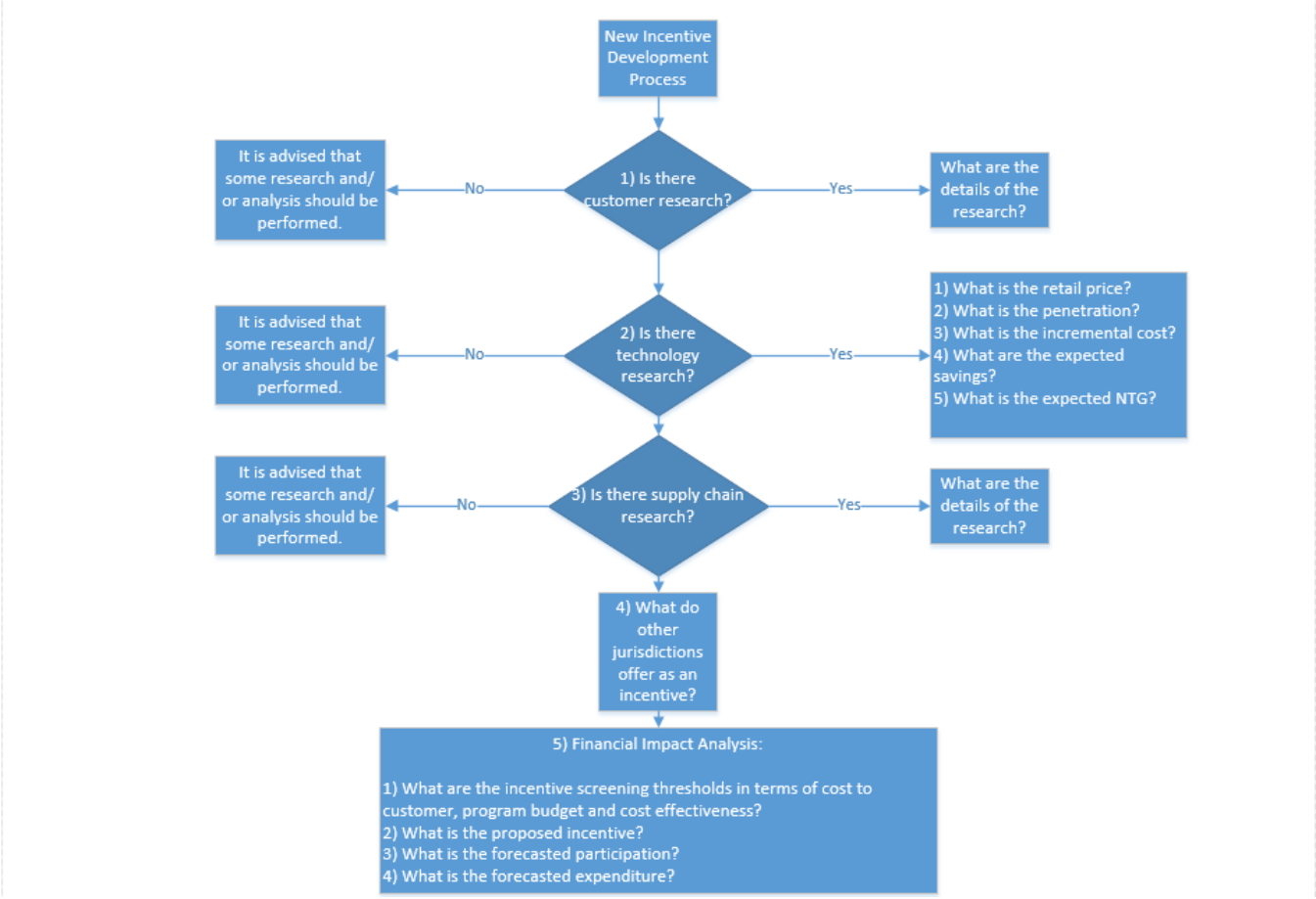
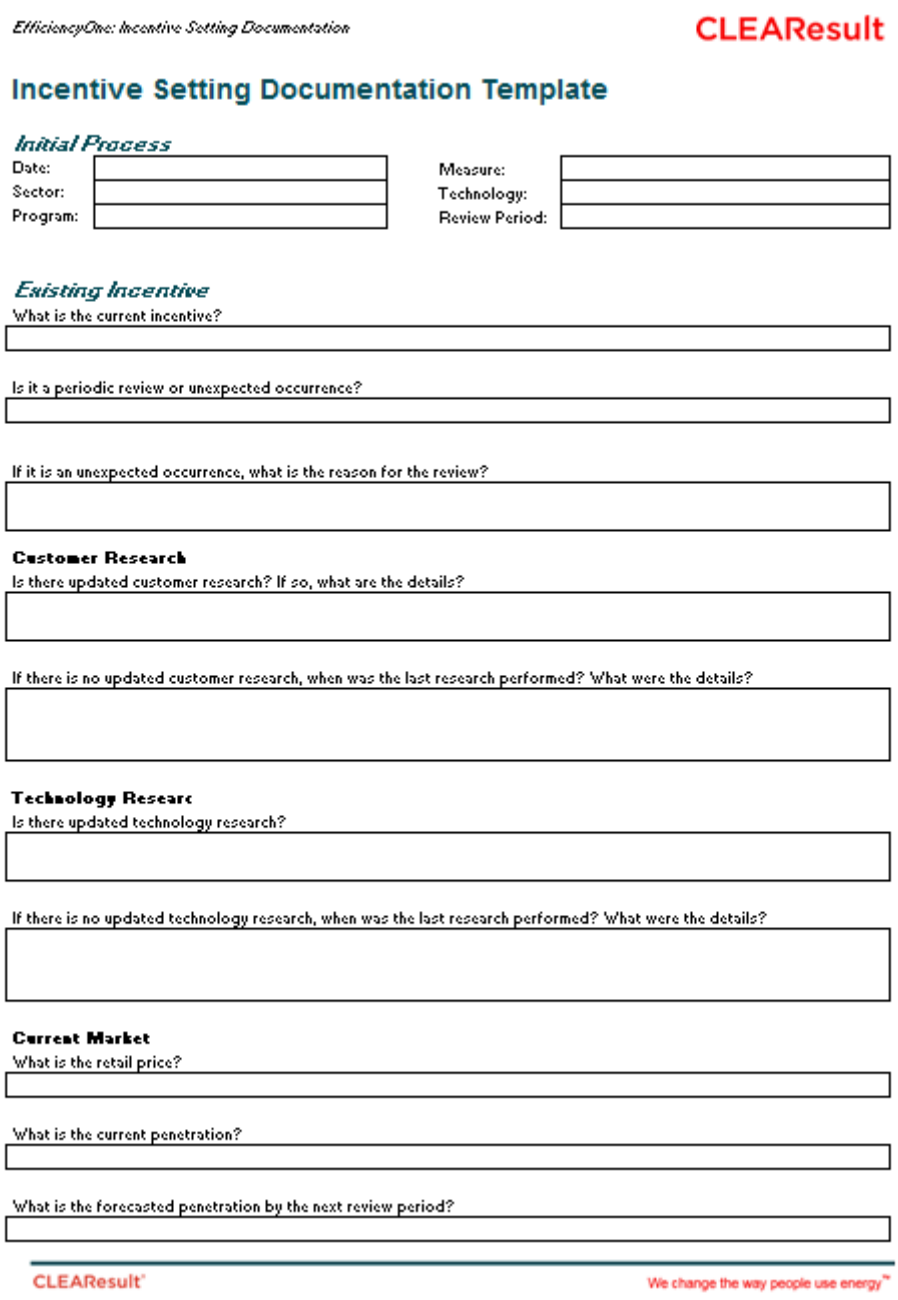


Figure 13: New Incentive Development Process

DOCUMENTATION

To complement the processes, CLEAResult is providing a template document that can be used for review and approval of any incentive setting exercise. This template document can provide a record of the considerations involved in setting the incentives, and can also serve as a platform for the review and approval process. The template document contains all of the required documentation steps in the flow charts, as indicated by the legend.

The template is provided as an attached Excel file, with a selected screenshot of the first page provided below:



EfficiencyOne: Incentive Setting Documentation

CLEAResult

Incentive Setting Documentation Template

Initial Process

Date:		Measure:	
Sector:		Technology:	
Program:		Review Period:	

Existing Incentive

What is the current incentive?

Is it a periodic review or unexpected occurrence?

If it is an unexpected occurrence, what is the reason for the review?

Customer Research

Is there updated customer research? If so, what are the details?

If there is no updated customer research, when was the last research performed? What were the details?

Technology Researc

Is there updated technology research?

If there is no updated technology research, when was the last research performed? What were the details?

Current Market

What is the retail price?

What is the current penetration?

What is the forecasted penetration by the next review period?

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INSTANT SAVINGS PROGRAM SUMMARY FOR CURRENT AND RECOMMENDED ACTIVITES

For the Instant Savings Program, CLEAResult has the following recommendations:

General Principle	Current Activities	Recommended Activities
Understand Technology Savings, Price and Market Penetration	For Instant Savings, EfficiencyOne gains an understanding of technology savings, price and penetration through the following activities: 1. Energy Efficiency Standards (Regulations); 2. Program Evaluation; 3. Industry Data; and 4. Specific Studies. In 2014, in response to upcoming codes and standards and penetration forecasts, EfficiencyOne eliminated CFLs from the program. This provides a recent example of proactivity regarding the incentive setting process. Annually, through the program evaluation process, the energy savings assumptions are reviewed, and updated as required. EfficiencyOne has active conversations with retailers (please see below) to understand market price and penetration information as well as access to other industry data for sales/shipments of certain products. Through the Achievable Potential Study conducted in 2014, EfficiencyOne has an understanding of the stock of different technologies in the residential sector, some of which are associated with the Instant Savings program.	• The current activities should be continued. • The recommendations in the General Principles section should be implemented to support this program. This covers both incentive level changes and introduction of new measures. • The energy savings assumptions validation should be expanded as required by the recommended TRM process outlined in the General Principles recommendations section. • LED-associated technology, such as dimmer switches whose savings are affected by the technology consumption, should also be updated annually for savings assumptions. *As discussed in General Principles, there should be annual reviews of the assumptions for LEDs in the residential and commercial sector. In the residential sector, the installed base of technology still seems to favour incandescent technology, but sales data shows LEDs increasing in penetration. This increased penetration is expected to happen quickly within the next five years. This anticipated transformation is the reason for the annual updates.*
Understand Customer Motivation and Barriers for Participation	For Instant Savings, EfficiencyOne gains an understanding of customer motivations and barriers through the following activities: 1. Market Research; and 2. Program Evaluation. In 2014, EfficiencyOne commissioned market research to identify the optimum rebate levels for products supported by the Instant Savings program. This research confirmed the incentive that customers would require to participate in the offer. Annually, through the program evaluation process, participant and non-participant surveys are conducted to determine free ridership and spillover savings.	• Conduct the price sensitivity research every year for the most popular program measures ≥ $400,000 in annual expenditure. • The participant and non-participant surveys should continue to be held annually, as they are required to evaluate customer motivation and barriers. • The recommended semi-annual survey for residential LED technology can be used to help understand customer motivations and barriers for this program.

General Principle	Current Activities	Recommended Activities
Understand Supply Chain and Service Provider Considerations	For Instant Savings, EfficiencyOne gains an understanding of the supply chain and service provider considerations through the following activities: 1. Ongoing Program Management; and 2. Program Evaluation. EfficiencyOne conducts annual one-on-one meetings with participating retailers and manufacturers to identify stocking plans, product pricing and joint marketing strategies for the following year. This provides insight into the technology assessment required for the TRM process. It is recommended that these annual meetings continue. Additionally, the delivery agent provides EfficiencyOne with an open channel of communication to retailers and manufacturers. Through the annual program evaluation process, there are interviews conducted with retailers and the delivery agent to understand their perspective, and suggestions for improvement.	• The current activities should be continued. EfficiencyOne, both through active program management (including with the delivery agent) and through the program evaluation process, receive insight from the supply chain. This communication is encouraged to continue, and this insight to be frequently sought out. This insight can also support the recommended market and technology research activities. • Additionally, it is recommended that EfficiencyOne try and understand if retailers or manufacturers will provide their own incentives on products during the next campaign or immediate program period. It may be difficult to gather this insight as it is understood that retailers reserve the right to make “game time” decisions regarding product sales. A complementary incentive will greatly affect uptake through increased participation, and ideally, it should be accounted for in any incentive analysis. This insight becomes even more valuable since real-time reporting of program activity is difficult to achieve for this program, which prevents instant correction.
Understand Financial Impacts	For Instant Savings, EfficiencyOne gains an understanding of financial impacts through the following activities: 1. Program Evaluation; 2. Program Planning; and 3. Financial Analysis. During the program evaluation process, the energy savings assumptions and net-to-gross ratios are reviewed, and updated as required. These inputs affect the cost effectiveness impact. During the DSM planning process, a cost effectiveness forecast is developed with all measures, programs, and the portfolio being screened for cost effectiveness using the TRC and PAC. Regulatory requirement is TRC of ≥1.0 at the program level. Since retailers require at least six months’ notice, incentive levels are not changed during campaigns. When an incentive change is proposed during the program planning process, EfficiencyOne conducts a financial forecast to track the budget impact.	• The current activities should be continued. • The recommendations in the General Principles section should be implemented to support this program. This covers both incentive level changes and introduction of new measures.

Table 21: Instant Savings Program Recommendations

Other Considerations for the Instant Savings Program

The current price floor for a participating measure is $0.99, regardless of the incentive. This floor ensures the customer pays something for the measure, and may assist with increasing the Net-to-Gross ratio. The price floor plays a similar role to incentive caps in commercial sector programs that require customers to contribute a portion of the incremental equipment or project cost. This is not possible with a point-of-purchase retailer program, since the cashier at the retailer cannot perform individual calculations on project costs or percentage contributions. However, to provide similar protection as the commercial sector programs, ENS may choose to consider different price floors for different measures in Instant Savings, based on their anticipated retail prices and the incremental equipment costs because customer contribution caps are rarely reached in the commercial sector programs, so the protection is rarely encountered.

CUSTOM PROGRAM SUMMARY FOR CURRENT AND RECOMMENDED ACTIVITIES

For the Custom Program, CLEAResult has the following recommendations:

General Principle	Current Activities	Recommended Activities
Understand Customer Motivation and Barriers for Participation	For the Custom Program, EfficiencyOne gains an understanding of customer motivations and barriers through: 1. Market Research; 2. Ongoing Program Management; 3. Program Benchmarking; and 4. Program Evaluation. <u>Market Research</u> In 2014, EfficiencyOne conducted research into the existing market barriers and consequentially the required support that businesses need to pursue energy efficiency options. This research indicated that financial support is critical for participation. For the New Construction component, customer surveys found that program implementation incentives of $1/square foot were insignificant compared to the total construction costs of $100-$200/square foot. Because of these surveys, ENS understood that financial incentives were not driving participation decisions, and that an educational incentive was more valuable in terms of energy modeling and commissioning expertise, in combination with giving customers access to financial incentives in Custom and through another program, the Business Energy Rebates. <u>Ongoing Program Management</u> Through general program management, EfficiencyOne has business development managers who are responsible for major customers. The business development managers are frequently in contact with customers. This direct customer communication and project payback documentation requirements provide key data points that EfficiencyOne uses	• Market research should continue to be conducted, especially for areas that are underperforming in terms of participation. • From the recommendations in the General Principles, the semi-annual surveys for commercial fluorescent technology, commercial LED technology, and commercial VFD technology can be used to help understand customer motivations and barriers. • ENS should continue its current program management, program benchmarking (required for new programs) and program evaluation activities to understand motivations and barriers for the large commercial and industrial sector. If possible, ENS should attempt to aggregate this research, and conduct segmentation analyses to develop a commercial sector market characterization.

Table 22: Custom Program Recommendations

	for incentive level setting and understanding customer motivation barriers. Through ongoing program management efforts, the limited uptake in the low cost financing offer indicates that direct financial support in the form of an incentive is more attractive, versus alleviating cash flow and capital purchasing concerns. For larger Custom Retrofit projects, EfficiencyOne has seen a 10 percent uptake on financing, indicating that some larger customers are sensitive to capital outlays and cash flow considerations. This level of uptake in financing has not been observed for smaller Custom projects or the residential sector. The small business sector has seen a significant uptake in financing in the past, Through the delivery of the Custom Compressed Air Optimization service, customers frequently identified that they were aware that their compressed air networks leaked, but they did not know how to assess the leaks or quantify the potential savings from optimization. EfficiencyOne introduced a new education incentive that provided technical assistance to customers to address these knowledge gaps. Customers were then offered an incentive to fix the leaks. The results from the educational incentive for leak fixing led to the deployment of low incentive costs for annual savings. <u>Program Benchmarking</u> When the Custom Retrofit program was designed in 2008, the initial incentive was designed using a $/kWh incentive rate based on a similar program by Manitoba Hydro. It was unknown what incentive level customers in Nova Scotia would respond to. Through program experience and discussions with customers, this incentive rate now sets a ceiling for individually negotiated incentives with each prospective program participant. <u>Program Evaluation</u> Through the annual program evaluation process, participant surveys are conducted to determine free ridership and spillover savings.	

Understand Technology Savings, Price and Market Penetration	For the Custom Program, EfficiencyOne gains an understanding of technology savings, price and penetration through ongoing program management. EfficiencyOne currently captures all technology savings and cost information through the feasibility study and/or project application process which are the best methods for obtaining this information, especially if it is supported by engineering calculations, technical due diligence and vendor invoices.	• Continue the current activities of collecting the energy savings and cost information through the feasibility studies and/or program application process. Due to the variability in operating hours in the commercial sector, this is important information for determining the energy savings. • The recommendations in the General Principles section should be implemented to support this program. This covers incentive level changes. • Additionally, EfficiencyOne should start tracking project type data so that it can be matched with the measure type to provide insight into general participation trends in participation, which will assist with analyzing market penetration. The semi-annual surveys for commercial fluorescent technology, commercial LED technology and commercial VFD technology can be used to complement the analysis of market penetration. • EfficiencyOne should engage the supply chain to gather insight into the types of projects they are expecting and any forecasted changes in costs or savings due to increased adoption or new efficiency options. This insight assists with market penetration analysis. The recommended supply chain engagement events in the General Principles section can be leveraged for this work. Below are two examples for large savings opportunities provided with Nova Scotia's market characteristics in mind: 1. Space cooling systems that feature direct expansion technology, either through incentives for purchasing efficient equipment or controllers, or for system maintenance. This analysis would assist with setting incentive levels for these measures. 2. Electric baseboard space heating systems especially for the installation of controls or with major renovation projects. This analysis would assist with setting incentive levels for these measures. • Finally, the incentive screening thresholds for program budget and cost effectiveness should be established on a per kWh basis for the Custom Program. It may be better to do this on a lifetime kWh basis, or account for energy savings persistence separately. Since the avoided costs are consistent amongst time periods in Nova Scotia, the incentive screening threshold (per kWh) is the same for any measure that has the same amount of energy savings persistence. These numbers should be calculated and updated every time the avoided costs are

		updated, consistent with the recommendations in the General Principles section.
Understand Supply Chain and Service Provider Considerations	For the Custom Program, EfficiencyOne gains an understanding of the supply chain and service provider considerations through: 1. Ongoing Program Management and 2. Program Evaluation. <u>Ongoing Program Management</u> Through the program management/account management process and the development of the different feasibility studies, EfficiencyOne's Business Development Managers regularly interact with the supply chain. <u>Program Evaluation</u> Through the annual program evaluation process, there are interviews conducted with select supply chain partners to understand their perspectives and suggestions for improvement.	• The current activities should be continued. • EfficiencyOne's should use its active program management and program evaluation processes to actively solicit insight from the supply chain and to support recommended market and technology research activities. • The major reason for continued engagement of the supply chain (beyond good program management) is to understand market penetration of the different technologies and to validate findings regarding customer motivations and barriers.
Understand Financial Impacts	For the Custom Program, EfficiencyOne gains an understanding of financial impacts through: 1. Individual Project Screening; 2. Ongoing Program Management; and 3. Program Evaluation. During the review of the project application, a TRC cost effectiveness analysis is conducted for each project to confirm eligibility. Due to ongoing program management (the individual negotiations of financial incentives), the budget impact is always being quantified from both a total financial impact and a unit cost perspective. During the program evaluation process, the energy savings assumptions and NTG ratios are reviewed and updated as required. These inputs affect the cost effectiveness impact.	CLEAResult recommends that: • The current activities should be continued. • The recommendations in the General Principles section should be implemented to support this program including incentive level changes. • The individual project screening for cost effectiveness should be expanded to include the PAC as well.

Other Considerations for the Custom Program

The Custom Program Retrofit incentive provides a level of flexibility that is best-in-class. Incentives are individually negotiated, based on four different parameters:

1. Capped at percentage of project costs;

2. Capped by simple payback;
3. Informed by incentive rate ($/kWh of first year savings); and
4. Capped at total dollar amount.

Through obtaining energy savings, project costs and required payback thresholds from the customer, the program has complete visibility into the potential financial implications of the incentive from the customer, the utility and society's perspective. This allows ENS to set an incentive that satisfies all three perspectives. Additionally, any costs for feasibility studies are included in the final incentive payment.

Current program data indicates that incentives are on average 20-25 percent of project costs, while they contribute to just under 60 percent of the program expenditure. Total program expenditure is averaging $0.10/kWh - $0.15/kWh, with a split between lighting and non-lighting projects that is beginning to skew towards non-lighting. The incentives typically result in a 2-3 year simple payback, though some institutions will accept a lower payback threshold.

In Nova Scotia, the avoided supply costs for energy do not differentiate the benefits derived associated with the time of the energy savings. This means there is not a cost effectiveness benefit (from energy savings) to promoting a diversity of measures in the portfolio. ENS should be encouraged to continue to promote more non-lighting measures to encourage portfolio diversity. The current incentive framework provides the flexibility to do so without changing any of the current parameters; this minimizes the impact of any such change.

Another issue to be aware of is being able to deal with participant and potential participant communication. Since the incentives are individually negotiated, there is the possibility for increased incentive costs due to information sharing and/or collusion. However, the current incentive framework caps protect against this risk. There is also the additional protection of the incentive contract containing a confidentiality clause regarding the amount of the incentive.

Finally, since the location of the energy savings are known, the consideration of local avoided costs with premium and discount zones can be applied to the Custom Program and can be used to influence the incentive negotiation. EfficiencyOne can implement these considerations once the local avoided costs are developed.

BUSINESS ENERGY REBATES CURRENT AND RECOMMENDED ACTIVITIES

For the Business Energy Rebates program, CLEAResult has the following recommendations:

General Principle	Current Activities	Recommended Activities
Understand Customer Motivation and Barriers for Participation	For the Business Energy Rebates Program, EfficiencyOne gains an understanding of customer motivations and barriers through: 1. Market Research; 2. Ongoing Program Management; 3. Program Benchmarking; and 4. Program Evaluation. <u>Market Research</u> In 2014, EfficiencyOne conducted research into the existing market barriers and, consequentially, the required support that businesses need to pursue energy efficiency options. This research indicated that financial support is critical for participation. <u>Ongoing Program Management</u> Through general program management, EfficiencyOne has a Business Development Manager that is dedicated to reaching out to participating distributors. Distributors can provide insight on the contractor and customer program experience. EfficiencyOne also has dedicated Application Coordinators for application support and approval in the program. They work with both the distributors in the midstream program and customers who access the downstream application process. Through these efforts, as well as the need for project invoices to be submitted, reference points are provided for what is acceptable in terms of an incentive, when understanding customer motivation and barriers. <u>Program Benchmarking</u> When the original program was designed, the incentives were based on a similar program that was offered for Efficiency Vermont, with adjustments made for different product pricing in the two jurisdictions. <u>Program Evaluation</u> Through the annual program evaluation process, participant surveys are conducted to determine free ridership and spillover savings. Through these surveys, their motivations and barriers are determined.	• Continue to conduct the market research, especially for areas where participation is underperforming. • From the recommendations in the General Principles, the semi-annual surveys for commercial fluorescent technology, commercial LED technology, and commercial VFD technology can be used to help to understand customer motivations and barriers. • Continue all current program management, program benchmarking (as required for new programs) and program evaluation activities to develop a clear understanding of motivations and barriers existing within the commercial and industrial sector. If possible, EfficiencyOne should aggregate this research, and conduct segmentation analyses to develop a commercial sector market characterization.

General Principle	Current Activities	Recommended Activities
Understand Technology Savings, Price and Market Penetration	For the Business Energy Rebates program, EfficiencyOne gains an understanding of technology savings, price and penetration through: 1. Ongoing Program Management and 2. Program Evaluation. <u>Ongoing Program Management</u> EfficiencyOne currently captures technology savings and cost information through discussions with the manufacturers and distributors, as well as through the submission of project invoices, which confirm product pricing. <u>Program Evaluation</u> Through the annual program evaluation process, the energy savings assumptions are reviewed, and updated as required.	• Continue the current activities of engaging the supply chain and reviewing the project invoices to understand technology savings and pricing. • Investigate the potential to develop a method, beyond randomized audits, to document and understand the different operating hours for the program participants in the Instant Rebates stream because those hours are highly variable within the commercial sector. It is understood that a runtime analysis has been conducted recently. • Implement the recommendations in the General Principles section to support this program. Those recommendations include both incentive level changes and introduction of new measures. • EfficiencyOne should start to understand the technology penetration of the different products in the program. The semi-annual surveys for commercial fluorescent technology, commercial LED technology and commercial VFD technology can be used to complement the analysis of market penetration.
Understand Supply Chain and Service Provider Considerations	For the Business Energy Rebates program, EfficiencyOne gains an understanding of the supply chain and service provider considerations through: 1. Ongoing Program Management and 2. Program Evaluation. <u>Ongoing Program Management</u> Through the delivery of the program, EfficiencyOne interacts with the supply chain regularly through the Program Manager, Business Development Manager and Application Coordinators. <u>Program Evaluation</u> Through the annual program evaluation process, interviews are conducted with select supply chain partners to understand their perspectives and suggestions for improvement.	• EfficiencyOne should continue these current activities.
Understand Financial Impacts	For the Business Energy Rebates Program, EfficiencyOne gains an understanding of financial impacts through: 1. Ongoing Program Management and 2. Program Evaluation.	• EfficiencyOne should continue these current activities. • Implement the recommendations in the General Principles section to support this program. This

General Principle	Current Activities	Recommended Activities
	Ongoing Program Management Due to ongoing program management, the costs of the products are always monitored. This monitoring allows the Program Manager to understand whether incentives are too high compared to the Incremental Equipment Cost, and whether the 50 percent financial cap is being reached. Program Evaluation During the program evaluation process, the energy savings assumptions and net-to-gross ratios are reviewed, and if required, they are updated. These inputs affect the cost effectiveness impact.	covers both incentive level changes and introduction of new measures.

Table 23: Business Energy Rebates Program Recommendations

Other Considerations for Business Energy Rebates Program

From reviewing program operations, the Business Energy Rebates program tracks retail pricing through the application process. This allows program managers to understand if incentive levels are too high compared to the retail prices, using the first type of incentive screening threshold, which is the cost to the customer. The program is forecast to have a high PAC, which assumes that the cost effectiveness threshold is not in danger of being breached due to incentives being too high. As long as there is continued active program tracking to monitor program budgets and the retail prices, the program should be effective in setting appropriate incentive levels. It is understood that similar to the retail program, customer/project information is not provided for the Instant Rebates stream. With this chosen program delivery structure, it will be difficult to include premium and discount zones to align with local avoided costs, when they are available.

HOME ENERGY ASSESSMENT CURRENT AND RECOMMENDED ACTIVITIES

For the Home Energy Assessment program, CLEAResult has the following recommendations:

General Principle	Current Activities	Recommended Activities
Understand Customer Motivation and Barriers for Participation	For the Home Energy Assessment Program, EfficiencyOne gains an understanding of customer motivations and barriers through the following activities: 1. Market Research; 2. Ongoing Program Management; 3. Program Benchmarking; and 4. Program Evaluation. <u>Market Research</u> EfficiencyOne conducted research with the participants in the Home Energy Assessment program. It was found that some customers were implementing a subset of recommended measures after receiving an audit report, although they did not complete a final audit to receive the incentives. The research found that the initial audit provided benefit to homeowners, and that it was the key to lowering unit costs for the program, through the tracking of the program-enabled/spillover savings. This was one of the factors that led to the decision to subsidize the audit incentive further. In 2014, EfficiencyOne commissioned research to identify the incentive levels and financing options required to encourage homeowners to make major efficiency upgrades (> $5,000). The research found that a 25 percent incentive would have a greater impact than interest-free financing. This is an example of a conjoint analysis, where different benefits of the program were evaluated to determine their individual contribution to value for the customer. EfficiencyOne conducted demographic research to understand the characteristics of the general population, program participants and non-participants. <u>Ongoing Program Management</u> Through general program management, EfficiencyOne frequently interacts with the service organizations and contractors to understand what customers are saying, and what are their motivations and barriers. Through these efforts as well as the need for project receipts to be submitted by participants, there can be a triangulation point for what is acceptable in terms of an incentive when understanding customer motivation and barriers. <u>Program Benchmarking</u> When the original program was designed, the incentives were based on a similar program offered by the Federal government. The rebates from the federal government were discontinued in 2012, with a corresponding reduction in participation. <u>Program Evaluation</u> Through the annual program evaluation process, participant surveys are conducted to determine free ridership and spillover savings. Through these surveys, their motivations and barriers are determined.	• It is recommended that market research continue to be conducted, especially for areas that are underperforming in terms of participation, either in terms of technology, demographic segments or geographical areas. • As per the recommendations in the General Principles, the semi-annual surveys for residential HVAC technology should be conducted to help understand customer motivations and barriers. • EfficiencyOne should continue all of the current activities with regards to ongoing program management, program benchmarking (as required for new measures) and program evaluation.

General Principle	Current Activities	Recommended Activities
Understand Technology Savings, Price and Market Penetration	For the Home Energy Assessment program, EfficiencyOne gains an understanding of technology savings, price and penetration through the following activities: 1. Ongoing Program Management and 2. Program Evaluation. <u>Ongoing Program Management</u> EfficiencyOne captures technology savings through the confirmation of the information in the final audit report. There are also frequent discussions with the service organizations that help support this analysis. <u>Program Evaluation</u> Annually, through the program evaluation process, the energy savings assumptions are reviewed, and updated as required.	• The current activities of engaging the Service Organizations and Natural Resources Canada to understand technology savings should be continued. • The recommendations in the General Principles section should be implemented to support this program. This covers both incentive level changes and introduction of new measures. • Additionally, EfficiencyOne should start to understand the technology penetration of the residential HVAC and building envelope technologies in the program. The Achievable Potential study indicates that Nova Scotia has a significant base of primary and secondary electric heating systems. As the technology mix changes due to the increased price of electricity and the decreased in costs of other options, the base case assumptions may change.
Understand Supply Chain and Service Provider Considerations	For the Home Energy Assessment program, EfficiencyOne gains an understanding of the supply chain and service provider considerations through the following activities: 1. Ongoing Program Management and 2. Program Evaluation. <u>Ongoing Program Management</u> Through the delivery of the program, EfficiencyOne interacts with the supply chain regularly through the discussions with the service organizations. <u>Program Evaluation</u> Through the annual program evaluation process, there are interviews conducted with select supply chain partners (Service Organizations) to understand their perspective, and suggestions for improvement.	• The current activities should be continued.

General Principle	Current Activities	Recommended Activities
Understand Financial Impacts	For the Home Energy Assessment program, EfficiencyOne gains an understanding of financial impacts through the following activities: 1. Program Evaluation. <u>Program Evaluation</u> During the program evaluation process, the energy savings assumptions and net-to-gross ratios are reviewed, and if required, they are updated. These inputs affect the cost effectiveness impact.	• The current activities should be continued. The recommendations in the General Principles section should be implemented to support this program. This covers both incentive level changes and introduction of new measures.

Table 24: Home Energy Assessment Program Recommendations

Other Considerations for the Home Energy Assessment Program

The Home Energy Assessment program recently introduced an updated incentive structure, which featured an increased incentive for the initial audit, and premiums associated with bundling of incentives to encourage larger projects from participants. It will be of interest to see how these changes are received by customers, and whether there is an increase in participation and/or in savings. From the initial data that CLEAResult has received, it appears that the bundling approach is showing some promising results. The average savings realized per participating home have increased, with the unit cost for delivery decreasing. It is difficult to isolate the effects of bundling since there were changes implemented to both the audit and measure incentive amounts that were introduced at the same time.

It has been observed that bundling is an effective tactic in encouraging participation. Retailers frequently use bundling in their sales strategies to clear inventory. When applied to the energy efficiency program space, bundling may be a worthwhile tactic for programs where there is a significant resource expenditure for customer acquisition. This is because any increases in unit costs (when compared to an unbundled incentive offer) may be offset by generating the additional savings from the expenditure associated with customer acquisition. In short, if customer acquisition is a sunk cost, it may make sense to leverage as much as possible from that cost.

The provision of the personal energy planning services has helped customers understand their options and increased the savings from each project. Since delivery of the program is through the participating service organizations, and the project locations are clearly identified, there may be the opportunity to include premium and discount zones for incentives to align with local avoided costs.

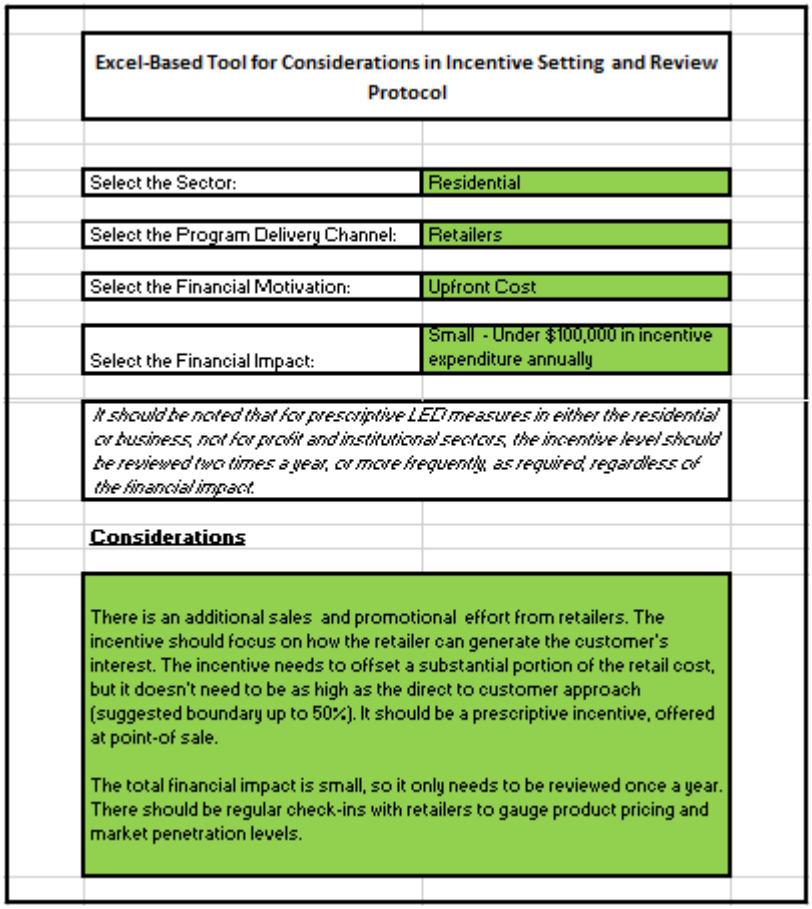
Incentive Level-Setting Excel-Based Tool for Review Protocol

To assist with determining incentive levels, CLEAResult has developed an Excel-based tool (which is provided as a separate file). The tool requires certain parameter inputs, and using those, provides a set of considerations that can be used in setting incentive levels. The considerations are not exhaustive, but they can provide a platform for the analysis. When combined with the general principles, incentive-setting process flow and the incentive documentation template, EfficiencyOne will have a set of recommendations and tools to assist with determining incentives. The tool does not provide any specific financial recommendations for incentives.

The input parameters for the tool are as follows:

- Sector
  - Residential
  - Business, Not for Profit and Institutional (Commercial) and Industrial
- Program Delivery Channel
  - Direct to Customer
  - Contractors
  - Retailers
  - Distributors
  - Other Vendors
- Financial Motivation for Participant
  - Upfront Cost
  - Payback
- Financial Impact
  - Small (under $100,000 in annual measure incentive expenditure)
  - Medium (between $100,000 - $400,000 in annual measure incentive expenditure)
  - Large (greater than $400,000 in annual measure incentive expenditure)

Once these parameters are selected, a set of considerations are provided that should be used in the incentive setting process.



Excel-Based Tool for Considerations in Incentive Setting and Review Protocol

Select the Sector:	Residential
Select the Program Delivery Channel:	Retailers
Select the Financial Motivation:	Upfront Cost
Select the Financial Impact:	Small - Under $100,000 in incentive expenditure annually

It should be noted that for prescriptive LED measures in either the residential or business, not for profit and institutional sectors, the incentive level should be reviewed two times a year, or more frequently, as required, regardless of the financial impact.

Considerations

There is an additional sales and promotional effort from retailers. The incentive should focus on how the retailer can generate the customer's interest. The incentive needs to offset a substantial portion of the retail cost, but it doesn't need to be as high as the direct to customer approach (suggested boundary up to 50%). It should be a prescriptive incentive, offered at point-of sale.

The total financial impact is small, so it only needs to be reviewed once a year. There should be regular check-ins with retailers to gauge product pricing and market penetration levels.

Figure 14: Excel-Based Tool for Review Protocol

It should be noted that for prescriptive LED measures in either the residential or business, not for profit and institutional sectors, the incentive level should be reviewed two times a year, or more frequently as required, regardless of the financial impact.

Program Financial Simulation Analysis

INSTANT SAVINGS PROGRAM FINANCIAL SIMULATION

For the Instant Savings Program, the program financial simulation analysis included the following six steps for each measure:

1. Identify the current (2015) participation and incentive level;
2. Determine the market penetration;
3. Determine an appropriate cost to customer incentive level threshold;
4. Determine an appropriate program budget incentive level threshold;
5. Determine an appropriate cost effectiveness incentive level threshold; and
6. Compare the current incentive level to the three thresholds to determine if a change was required

The following table includes the measure parameters obtained from EfficiencyOne:

Measure Parameters

Measure	Current Incentive Level ($)	2015 Participation	Incentive Expenditure*	Per Unit Net Energy Savings (kWh)**	Per Unit Net Peak Demand Savings (kW)***	Energy Savings Persistence (Years)
ENERGY STAR® LED A Lamp	$3.00	253,461	N/A	25.5	1.021	25
ENERGY STAR® LED Specialty Lamp	$5.00			25.5	1.021	25
ENERGY STAR® LED Recessed Downlight	$12.00	8,709	$104,508	51.9	0.072	16
ENERGY STAR® LED Fixture	$12.00	7,291	$87,492	151.8	0.175	13
Dimmer Switch	$4.00	6,430	$25,720	18.7	0.019	10
Indoor Motion Sensor	$5.00	439	$2,195	50.4	0.003	10
Motion Sensor with Dimmer Switch	$5.00	5	$25	59.0	0.000	10
Outdoor Motion Sensor	$5.00	569	$2,845	174.9	0.015	10
Power Bar with Timer	$5.00	71	$355	59.1	0.001	10
Smart Power Bar	$10.00	299	$2,990	59.2	0.003	10
Heavy-Duty Timer	$10.00	1,558	$15,580	134.2	0.033	10
Programmable Thermostat	$15.00	4,799	$71,985	243.1	0.185	11
Outdoor Clothesline	$5.00	1,448	$7,240	165.0	0.037	10

Table 25: Instant Savings Measure Parameters

Obtained from taking the current incentive multiplied by the 2015 participation. It does not account for any change in incentive levels in 2015.

**Determined by adjusting the per unit gross energy savings for interactive effects, the NTG ratio and line losses.*

**** Determined by adjusting the per unit gross demand savings for interactive effects, the NTG ratio and line losses.*

It should be noted that CLEAResult did not review the individual measure assumptions for the per unit energy and peak demand savings, and energy savings persistence.

Market Penetration

From reviewing the baseline study for the residential sector (a component of the DSM Potential Study[1]), and other data provided by EfficiencyOne, CLEAResult has developed the current estimates for market penetration of the measures. It should be noted that these are estimates only.

Measure	Estimated Market Penetration
ENERGY STAR® LED A Lamp	Low (under 30%)
ENERGY STAR® LED Specialty Lamp	Low (under 40%)
ENERGY STAR® LED Recessed Downlight	Low (under 30%)
ENERGY STAR® LED Fixture	Low (under 30%)
Dimmer Switch	Unknown
Indoor Motion Sensor	Unknown
Motion Sensor with Dimmer Switch	Unknown
Outdoor Motion Sensor	Unknown
Power Bar with Timer	Unknown
Smart Power Bar	Low (under 30%)
Heavy-Duty Timer	Unknown
Programmable Thermostat	Low (under 40%)
Outdoor Clothesline	High (over 50%)

*For the purposes of this analysis, the unknown market penetrations were assumed to be under “Low (under 40%)”. The incentive for outdoor clotheslines should be investigated, since their usage may already be standard practice in Nova Scotia.

Table 26: Market Penetration of Instant Savings Measures

[1] Nova Scotia 2015-2040 Demand Side Management (DSM) Potential Study – Navigant Consulting

Cost to Customer Incentive Level Threshold

As discussed in the Financial Impact Analysis section of the General Principles recommendations, a program that features residential customers making small purchases at retailers should use retail prices as the parameter for cost to customer. As per Table 27, CLEAResult suggests the cost to customer upper limit should be 50 percent for this type of incentive.

EfficiencyOne conducted price sensitivity research in 2014. The results of that analysis were used in this exercise. It should be noted that EfficiencyOne should update these numbers internally with the information provided from ongoing program management activities, as the estimated 2016 retail prices for the measures will be more accurate.

Measure	2014 Retail Price	2014 PMI	2014 PME	Estimated 2016 Retail Price	2016 Cost to Consumer (Estimated 2016 Retail Price – Current Incentive)	Estimated 2016 PME*	Cost to Consumer Less than PME?	Current Incentive as % of Retail Price
ENERGY STAR® LED A Lamp	$15.00	$5.00	$13.50	$12.00	$9.00	$13.50	Yes	25%
ENERGY STAR® LED Specialty Lamp	$30.00	$7.00	$20.50	$25.00	$20.00	$20.50	Yes	20%
ENERGY STAR® LED Recessed Downlight	$45.00	$20.20	$44.30	$45.00	$33.00	$44.30	Yes	27%
ENERGY STAR® LED Fixture	Not Included	Not Included	Not Included	$45.00	$33.00	$44.30	Yes	27%
Dimmer Switch	$30.00	$7.00	$20.70	$25.00	$21.00	$20.70	No	16%
Indoor Motion Sensor	$24.00	$10.10	$28.80	$25.00	$20.00	$28.80	Yes	20%
Motion Sensor with Dimmer Switch	Not Included	Not Included	Not Included	$30.00	$25.00	$24.84	No	17%
Outdoor Motion Sensor	$24.00	$15.00	$35.10	$25.00	$20.00	$35.10	Yes	20%
Power Bar with Timer	Not Included	Not Included	Not Included	$20.00	$15.00	$18.00	Yes	25%
Smart Power Bar	$50.00	$15.60	$45.00	$50.00	$40.00	$45.00	Yes	20%
Heavy-Duty Timer	Not Included	Not Included	Not Included	$20.00	$10.00	$18.00	Yes	50%
Programmable Thermostat	$30.00	$11.75	$29.99	$30.00	$15.00	$29.99	Yes	50%
Outdoor Clothesline	Not Included	Not Included	Not Included	$20.00	$15.00	$20.00	Yes	25%

*The Estimated 2016 PME was based on the 2014 PME

Table 27: Cost to Customer Incentive Threshold for Instant Savings Measures

It appears that in terms of the customer cost incentive level threshold, all of the current incentives are suitable. The only two measures where the current customer cost is more than the PME are the dimmer switch and the motion sensor with dimmer switch. The PME's of both these measures are based on the analysis for the dimmer switch. It should also be noted that the difference between the customer cost and the PME for both of these measures is ≤two percent of the customer cost.

From reviewing the current incentive compared to the retail price, all of the current incentive levels fall within acceptable ranges of typical retail sales events (between 10-30 percent). The only three measures that do not are ENERGY STAR® A Lamps, Heavy-Duty Timers and Programmable Thermostats.

ENERGY STAR A Lamps have low market penetration and deliver the highest amount of savings for the Instant Savings program. It is advised that based on the cost to customer incentive level threshold, the incentive level does not change.

Programmable Thermostats have low market penetration, so the cost to customer incentive level threshold (50 percent) being reached is justified.

The market penetration of heavy duty timers is unknown. The cost to customer incentive level threshold is not breached at 50 percent, so the incentive can be justified based on this threshold.

Program Budget Incentive Level Threshold

As discussed in the Financial Impact Analysis section of the General Principles recommendations, a program that features residential customers making small purchases at retailers should use $/kWh for the program budget impact. As per 14, CLEAResult suggests the program budget upper limit should be $0.50/kWh for this type of incentive. EfficiencyOne has a program budget of $0.26/kWh for this program. Based on historical expenditures, the costs for program administration have been between 20-30 percent of the total expenditure. Therefore, the incentive expenditure, on a $/kWh basis is as follows:

Parameter	Program Budget Incentive Level Threshold
Total Expenditure (Incentive + Program Administration)	$0.26/kWh
Incentive Expenditure (@ 30% Program Administration Expenditure)	$0.18/kWh
Incentive Expenditure (@ 20% Program Administration Expenditure)	$0.21/kWh

Table 28: Program Budget Incentive Level Threshold for Instant Savings Program

Each measure in the Instant Savings program has its associated program budget incentive level threshold listed below.

Measure	Current Incentive ($)	Per Unit Net Energy Savings (kWh)	Program Budget Incentive Level Threshold at 30% Program Administration Expenditure	Program Budget Incentive Level Threshold at 20% Program Administration Expenditure	Is Current Incentive Lower than Program Budget Incentive Level Threshold at 30% Program Administration Expenditure
ENERGY STAR® LED A Lamp	$3.00	25.5	$4.59	$5.35	Yes
ENERGY STAR® LED Specialty Lamp	$5.00	25.5	$4.59	$5.35	No
ENERGY STAR® LED Recessed Downlight	$12.00	51.9	$9.35	$10.91	No
ENERGY STAR® LED Fixture	$12.00	151.8	$27.33	$31.88	Yes
Dimmer Switch	$4.00	18.7	$3.37	$3.93	No
Indoor Motion Sensor	$5.00	50.4	$9.07	$10.58	Yes
Motion Sensor with Dimmer Switch	$5.00	59.0	$10.61	$12.38	Yes
Outdoor Motion Sensor	$5.00	174.9	$31.48	36.73	Yes
Power Bar with Timer	$5.00	59.1	$10.63	$12.40	Yes
Smart Power Bar	$10.00	59.2	$10.65	$12.43	Yes
Heavy-Duty Timer	$10.00	134.2	$24.16	$28.18	Yes
Programmable Thermostat	$15.00	243.1	$43.76	$51.05	Yes
Outdoor Clothesline	$5.00	165.0	$29.70	$34.65	Yes

Table 29: Program Budget Incentive Level Threshold for Instant Savings Measures

It appears that in terms of the program budget incentive level threshold, the majority of the current incentives are suitable. The only three measures that breach the program budget incentive level threshold are the ENERGY STAR specialty lamp, ENERGY STAR recessed downlight and the dimmer switch.

The current incentive for the ENERGY STAR specialty lamp is 9 percent higher than the program budget incentive level threshold (assuming a 30 percent program administration expenditure). It means a reduction of $0.41 from the current incentive of $5.00 to meet the threshold. The current incentive for the ENERGY STAR recessed downlight is 30 percent higher than the program budget incentive level threshold (assuming a 30 percent program administration expenditure). It means a reduction of $2.65 from the current incentive of $12.00 to meet the threshold.

The current incentive for dimmer switches is 20 percent higher than level threshold (assuming a 30 percent program administration expenditure). It means a reduction of $0.63 from the current incentive of $4.00 to meet the threshold.

It should be noted that EfficiencyOne has a program budget expenditure limit of $0.26/kWh. This is applied at the program level, which allows “less expensive budget impact” measures to subsidize “more expensive budget impact” measures.

Cost Effectiveness Incentive Level Threshold

EfficiencyOne has a PAC target of 1.9 for this program. For the calculation, it is assumed that program administration costs are 30 percent of total expenditure, which leaves the incentive costs at 70 percent of expenditure. Therefore the program administration expenditure is 43 percent of the incentive expenditure. This ratio can allow the PAC target to be adjusted to only include the incentive expenditure.

Alternatively, the program administration costs can be determined for each measure, and included in the cost effectiveness calculations. If this is done, the PAC threshold remains at 1.9.

To model PAC cost effectiveness for each individual measure, CLEAResult developed a simplified cost effectiveness calculator that makes several assumptions that aren't accurate in detailed cost effectiveness calculations as discussed, it is recommended that EfficiencyOne develop a cost effectiveness calculator for incentive level setting, and broader short-term program design purposes.

Measure	PAC of Current Incentive Level (including Program Administration Costs)	Is PAC of Current Incentive Greater than Cost Effectiveness Incentive Level Threshold (including Program Administration Costs)
ENERGY STAR® LED A Lamp	506.49	Yes
ENERGY STAR® LED Specialty Lamp	303.92	Yes
ENERGY STAR® LED Recessed Downlight	9.17	Yes
ENERGY STAR® LED Fixture	20.04	Yes
Dimmer Switch	5.32	Yes
Indoor Motion Sensor	4.10	Yes
Motion Sensor with Dimmer Switch	4.19	Yes
Outdoor Motion Sensor	14.84	Yes
Power Bar with Timer	4.37	Yes
Smart Power Bar	2.36	Yes
Heavy-Duty Timer	7.35	Yes
Programmable Thermostat	16.81	Yes
Outdoor Clothesline	17.57	Yes

Table 30: Cost Effectiveness Incentive Level Threshold for Instant Savings Measures

For all of the measures, the cost effectiveness incentive level threshold is not breached.

Comparison of Current Incentive to Incentive Level Thresholds

Measure	Current Incentive	Cost to Customer Threshold Exceeded?	Program Budget Threshold Exceeded?	Cost Effectiveness Threshold Exceeded?
ENERGY STAR® LED A Lamp	$3.00	No	No	No
ENERGY STAR® LED Specialty Lamp	$5.00	No	Yes	No
ENERGY STAR® LED Recessed Downlight	$12.00	No	Yes	No
ENERGY STAR® LED Fixture	$12.00	No	No	No
Dimmer Switch	$4.00	No	Yes	No
Indoor Motion Sensor	$5.00	No	No	No
Motion Sensor with Dimmer Switch	$5.00	No	No	No
Outdoor Motion Sensor	$5.00	No	No	No
Power Bar with Timer	$5.00	No	No	No
Smart Power Bar	$10.00	No	No	No
Heavy-Duty Timer	$10.00	Yes	No	No
Programmable Thermostat	$15.00	Yes	No	No
Outdoor Clothesline	$5.00	No	No	No

Table 31: Comparison of Current Incentive to Incentive Level Thresholds for Instant Savings Measures

Based on the comparison of the suggested incentive levels, it is proposed that all of the measures maintain their current incentive levels, except for programmable thermostats, heavy duty timers and outdoor clotheslines. These measures warrant further analysis.

Even though programmable thermostats have an incentive of 50 percent of their retail price, their low market penetration and high per unit energy savings make them important for future program success, especially when considering Nova Scotia's base of primary electric heating systems. Therefore, for market penetration and savings potential reasons, this incentive does not need to be updated at the moment.

For heavy-duty timers, the current incentives fall comfortably within the program budget and cost effectiveness incentive level thresholds. It is recommended that the input parameters for this analysis be confirmed, especially their market penetration. There may be an opportunity to reduce the incentive. For example, in Ontario, the incentive is only $4.00 for heavy-duty timers.

For outdoor clotheslines, while the suggested boundaries of the three incentive screening thresholds are not breached, it appears their market penetration is high, and their usage may be standard practice in Nova Scotia. Therefore, it is appropriate to consider reducing the incentive, or removing it since it may be in the early majority or late majority stage of market transformation as indicated by the Technology Adoption Curve.

CUSTOM PROGRAM FINANCIAL SIMULATION

For the Custom Program Retrofit track, the program financial simulation analysis included the following steps:

1. Identify the average project parameters for the analysis;
2. Determine an appropriate cost to customer incentive level threshold;
3. Determine an appropriate program budget incentive level threshold;
4. Determine an appropriate cost effectiveness incentive level threshold; and
5. Compare the current incentive level to the three thresholds to determine if a change was required

Identification of Parameters for Average Custom Retrofit Project

The parameters for an average Custom Retrofit project were provided by EfficiencyOne. To provide multiple options for modelling, three different measure archetypes were selected, each with varying degrees of energy savings persistence that are commonly seen in large custom projects. The energy savings persistence will only affect the cost effectiveness incentive level threshold. It should be noted that since an average measure archetype is used, CLEAResult can only comment on average project incentives, and not specific project incentives.

Measure	Average Gross Energy Savings per Project (MWh)	Average Gross Peak Demand Savings per Project (kW)	NTG	Average Net Energy Savings per Project (MWh)	Average Net Peak Demand Savings per Project (kW)	Energy Savings Persistence	Average Project Incentive ($)
Custom Project Retrofit Track	230.75	17.92	92%	212.29	16.49	10	$24,106
Custom Project Retrofit Track	230.75	17.92	92%	212.29	16.49	15	$24,106
Custom Project Retrofit Track	230.75	17.92	92%	212.29	16.49	20	$24,106

Table 32: Parameters for Average Custom Retrofit Project

Cost to Customer Incentive Level Threshold

As discussed in the Financial Impact Analysis section of the General Principles recommendations, a program that features commercial customers making either large capital equipment purchases or large project purchases should use the Incremental Equipment Cost or the project cost respectively, as well as simple project payback for the cost to customer. As per Table 17, CLEAResult suggests the cost to customer upper limit should be 50 percent of the project cost and no less than a one year simple project payback for this type of incentive. These are suggested boundaries for the incentive level, and the actual incentives will usually be much lower.

Measure	Project Cost ($)	Simple Project Payback	Current Cost to Customer	Cost to Customer Threshold	
Custom Project Retrofit Track	$96,424	4 years	25%	50%	2 years

Table 33: Cost to Customer Incentive Level Threshold for Average Project in Custom Retrofit

The cost to customer threshold is not breached for either the project cost or the simple payback period.

It is recommended that EfficiencyOne start determining Incremental Equipment Costs for each project, so that parameter can be analyzed as well.

Program Budget Incentive Level Threshold

As discussed in the Financial Impact Analysis section of the General Principles recommendations, a program that features commercial and industrial customers making either large capital equipment purchases or large project purchases should use $/kWh and total incentive for the program budget threshold. As per Table 18, CLEAResult suggests the program incentive budget upper limit should be $0.25/kWh and $500,000 for this type of incentive.

For the 2016 Custom Program, EfficiencyOne has a total expenditure limit of $0.20/kWh, so these numbers will be used instead of $0.25/kWh in evaluating the appropriateness of incentives. The program budget incentive threshold is not exceeded for the average custom retrofit project.

Measure	Program Budget Incentive Threshold	Current Program Budget Incentive
Custom Project Retrofit Track	$25,475	$24,106

Table 34: Program Budget Incentive Level Threshold for Average Project in Custom Retrofit

Cost Effectiveness Incentive Level Threshold

EfficiencyOne has a PAC target of 4.9 for this program. For the calculation, it is assumed that program administration costs are 40 percent of total expenditure, which leaves the incentive costs at 60 percent of expenditure. Therefore the program administration expenditure is 67 percent of incentive expenditure.

Measure	Energy Savings Persistence	Cost Effectiveness Threshold
Custom Project Retrofit Track	10	3.14
Custom Project Retrofit Track	15	4.50
Custom Project Retrofit Track	20	5.69

Table 35: Cost Effectiveness Incentive Level Threshold for Average Project in Custom Retrofit

As can be seen from the above analysis, the PAC is greater than 4.9 for measures that have an energy savings persistence greater than 15 years. The break-even point at current incentive and program administration cost targets is an energy savings persistence between 16-17 years. When evaluating individual project incentives, EfficiencyOne should take into consideration the energy savings persistence of the project.

Comparison of Current Incentive Level to Incentive Level Thresholds

Measure	Cost to Customer Incentive Level Threshold Exceeded?	Program Budget Incentive Level Threshold Exceeded?	Cost Effectiveness Incentive Level Threshold Exceeded?
Custom Project Retrofit Track	No	No	No

Table 36: Comparison of Current Incentive Level to Incentive Level Thresholds for Average Project in Custom Retrofit

The Custom Program has appropriate incentive levels for the average project.

A key consideration for EfficiencyOne is to start tracking Incremental Equipment Costs so that the cost to customer can be fully understood. The Incremental Equipment Costs are different than the project costs, and play more of a factor in equipment replacement decisions, versus new purchase,

The program budget incentive level threshold is not exceeded.

Finally, for projects where the energy savings persistence is less than 17 years, consideration should be given to potentially decreasing the incentive. An energy savings persistence between 16-17 years is the break-even point for the target cost effectiveness threshold.

Appendix A – Jurisdictional Scans

JURISDICTIONAL SCANS - GENERAL OBSERVATIONS

Jurisdiction	Peak Load (MW) or Annual Consumption (Therms)	Population Served	Types of Electricity Generation
Nova Scotia (ENS)	2,124 MW	≈950,000	Coal, Renewables, Natural Gas
Ontario Electricity	27,005 MW	≈13.8 million	Nuclear, Natural Gas, Hydroelectric
Union Gas	N/A	N/A	-
British Columbia (BC Hydro)	11,681 MW	>4.4 million	Hydroelectric, Thermal, Diesel-Generation
California (PG&E)			
Energy Trust of Oregon - Oregon			Coal, Hydroelectric, Natural Gas, Nuclear, Wind, Solar, Wood
Energy Trust of Oregon - Washington			
New York (ConEd)	12,316 MW	>9,000,000	Nuclear, Natural Gas, Hydroelectric, Other Renewables, Coal, Petroleum-Fired
New York (NYSERDA)			
Vermont (Efficiency Vermont)	1,255 MW*	≈500,000	Nuclear, Hydroelectric
Maine (Efficiency Maine)	1,863 MW*	1.33 million	Renewable, Hydroelectric, Natural Gas, Coal, Petroleum-Fired
Massachusetts (National Grid)	13,128 MW*	≈1.1 million	Natural Gas, Nuclear

*Peak for all of state

Table 37: Jurisdiction Overview

Jurisdiction	Current Framework Period	Annual Savings Target*	Annual Budget* ($ million)	% Incentive	Unit Cost of Savings Target	Target per Retail Sales	Residential Retail Rates
Nova Scotia (ENS)	2016-2018	135.3 GWh	$34.05	≈70%	$0.25/kWh	1.3%	$0.148/kWh
Ontario Electricity	2015-2020	1,450 GWh	$366.67	N/A	$0.25/kWh	1.3%	$0.10-$0.12/kWh
Union Gas	2015-2020	211,791,091 m3 (Cumulative Cubic Meters)	$51.05	N/A	$0.24/m3		$0.1069/m3
British Columbia (BC Hydro)	2007-2020	884 GWh	N/A	N/A	N/A	N/A	$0.10-$0.12/kWh
California (PG&E)	2016+ Rolling Portfolio	593 GWh	$365.1M	81%	$0.43/kWh	1%	$0.1625/kWh
Energy Trust of Oregon - Electricity	2015-2020	55.1 aMW	$141.3M	65%	N/A	N/A	$0.1109-$0.1137/kWh

Jurisdiction	Current Framework Period	Annual Savings Target*	Annual Budget* ($ million)	% Incentive	Unit Cost of Savings Target	Target per Retail Sales	Residential Retail Rates
Energy Trust of Oregon – Gas	2015-2020	6 MMTh	$26.3M		$4.38/Therm	N/A	10.59 - 11.72 $/Mcf
New York (ConEd)	2009-2015 (EEPS) 2012-2015 (EEPS II)	163.56 GWh (EEPS) ***Average	$78.25 (EEPS) $84.23 (EEPS II) ***Average		$0.48/kWh	≈1%	$0.2885/kWh
New York (NYSERDA)						≈1%	$0.2005/kWh
Vermont	2015-2017	107.27 GWh	$43.43	55%	$0.40/kWh	2%	$0.125-$0.195/kWh
Maine (Efficiency Maine)	2014-2016	136.03 GWh (Base) 191.43 GWh (MACE Low Cost)** 191.43 GWh (MACE High Cost) 54,057.3 Dth (Base) 118,016 Dth (MACE) ***Average	$26.87 (Electric Base) $58.04 (Electric MACE Low Cost) $67.03 (Electric MACE High Cost) $0.529 (Gas Base) $1.18 (Gas MACE) ***Average		$0.20/kWh (Electric Base) $0.30/kWh (MACE Low Cost) $0.35/kWh (MACE High Cost) $9.79/Dth (Base) $10.00/Dth (MACE)		$0.1567/kWh
Massachusetts/ National Grid	2016-2018	646.33	$299.20	80%	$0.46/kWh	2.94%	$0.165-$0.185/kWh

*Annual savings targets and budgets may be presented based on calculation of averages

Table 38: **Jurisdiction Savings Targets and Budgets**

APPENDIX A-1: ONTARIO ELECTRICITY

SUMMARY

Jurisdictional Scan	
State/Province	Ontario
Utility/Agency	Independent Electricity System Operator (IESO)
Fuel	Electricity
Key Contact/Interviewee	Evelyn Lundhild
Consultant	Mayuran Srikantha

JURISDICTION OVERVIEW

Electricity Market

The following entities are the key players in the electricity system in Ontario.

- Ontario Government - Ministry of Energy
- Ontario Energy Board (OEB)
- Independent Electricity System Operator (IESO)
- 72 Local Distribution Companies (LDCs)

The Ministry of Energy sets policy for the electricity sector, and is able to provide the IESO and the OEB with direction through the use of ministerial directives. Through these directives, the IESO received guidance to develop the 2015-2020 Conservation First Framework in collaboration with the 72 LDCs.

The OEB is responsible for providing oversight and regulating the LDCs and natural gas utilities in Ontario. As such, the OEB reviews the LDCs rate applications. Conservation activity is funded separately through the IESO, and is (generally) independent of the rate setting process. Previously, from 2011-2014, participation and performance in Conservation programs were mandatory as a condition of license. This condition has been relaxed slightly since all conservation activities for LDCs are now reviewed and approved by the IESO, but there are still some conservation performance specifications in their distribution licenses.

The IESO has four major roles with regards to the electricity system in Ontario:

1. Operates the real time and day ahead markets
2. Contracts with electricity generators for long-term supply
3. Coordinates the long-term electricity system planning process
4. Provides oversight for Ontario's electricity conservation efforts

With regards to the oversight of electricity conservation efforts, the IESO is responsible for setting individual LDC savings targets and budgets, approving their conservation (CDM) plans, ensuring consistency (where possible) with regards to incentives and program delivery for customers across Ontario, managing the EM&V process, providing innovation funding for both the private sector and LDCs to leverage, and for managing the reporting and financial settlement process with LDCs.

Electric Utilities

Ontario has 72 electric utilities (LDCs). The majority of them are municipally owned, but there are a few investor-owned utilities that operate in Ontario. For conservation and efficiency program purposes, they all follow the same guidelines, regardless of ownership structure.

The LDCs range in size. The two largest LDCs are Toronto Hydro and Hydro One, both with over 500,000 customers. In comparison, Atikokan Hydro, one of the smallest LDCs, has just over 1,600 customers.

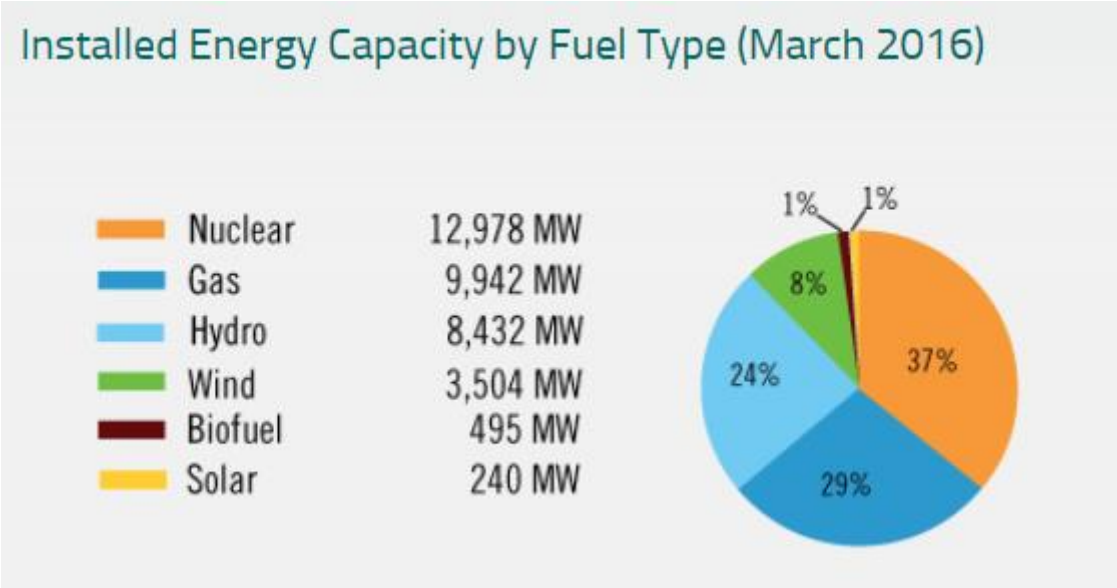
Electricity Generation

Ontario is a summer peaking province, with a peak load of 27,005 MW, which was recorded in August, 2006. Last year, the summer peak was over 22,000 MW. Some LDCs in Ontario are winter peaking.

In 2015, total electricity consumption was 114 TWh, with the sectors having the following individual consumptions:

- Residential: 45 TWh (39%)
- Commercial: 50 TWh (44%)
- Industrial: 19 TWh (17%)

Ontario's supply mix is as follows[1]:



ONTARIO ENERGY EFFICIENCY PROGRAM INCENTIVE AND COST EFFECTIVENESS POLICY

Conservation programs being delivered provincially though the IESO (formerly the OPA) started in 2006, through the delivery of third tranche programs by specific LDCs. Starting in 2007, certain programs began to be offered province-wide such as instant rebates for efficient products at participating retailers (then known as "Every Kilowatt Counts"), an appliance retirement program ("The Great Refrigerator Round up") and a business incentive program delivered through multiple partners ("ERIP", "BOMA", "MEER").

Cost Effectiveness Testing

In their conservation (CDM) plans, LDCs need to show portfolio cost effectiveness (TRC and PAC) if they are offering province-wide programs. If LDCs are offering local programs (only for their territory), those programs need to show program-level cost effectiveness. The only exception is the program to support the low-income sector which can have a TRC of 0.7. The TRC does include societal benefits, so it could be considered an SCT.

The IESO is responsible for maintaining cost effectiveness, both from a TRC and PAC perspective, for the programs province-wide and the entire portfolio.

[1] http://www.ieso.ca/Pages/Power-Data/Supply.aspx

Avoided Costs

For electricity, the major categories of benefit are:

- Avoided Capacity Costs
- Avoided Energy Costs
- Transmission and Distribution Costs
- 15% Adder for additional societal benefits
  - Environmental benefits
  - Employment benefits
  - Other societal benefits

ONTARIO (IESO) –OVERVIEW

Ontario Facts

Ontario covers a land area of 917,741 square kilometers. It has a population of just under 13.8 million people, which is almost 40 percent of Canada's entire population.

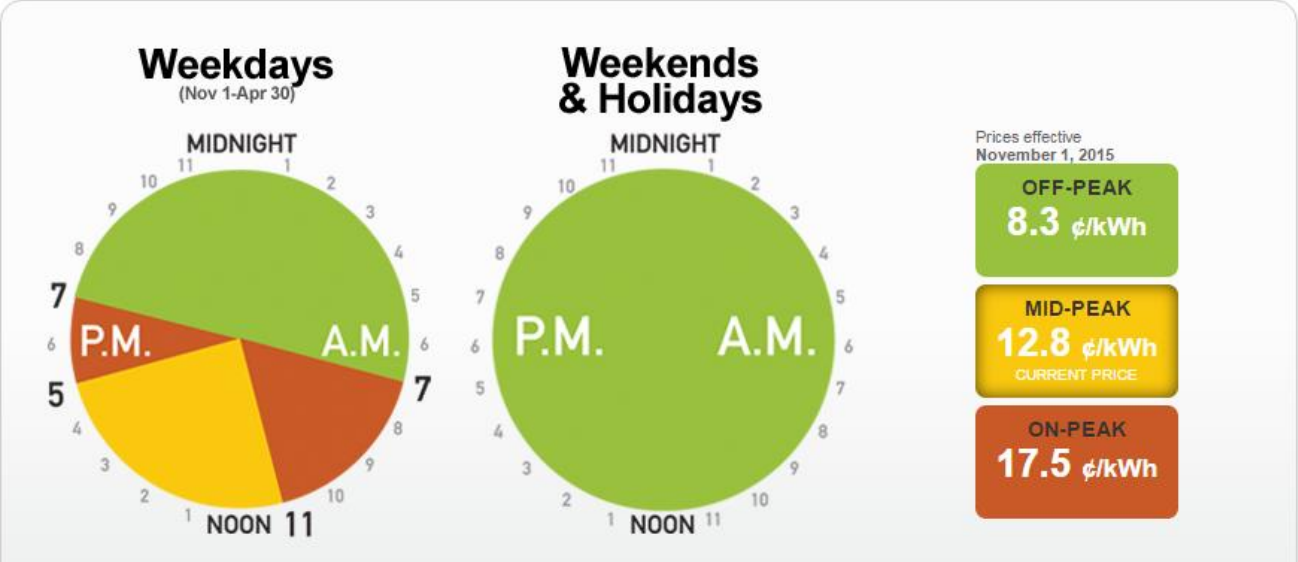
Customer Class Breakdown

In Ontario, there are 4,988,859 total electricity customers. The customers are broken down as follows:

- Residential Accounts: 4,502,650
- GS < 50 kW: 430,842
- GS >= 50 kW: 54,688
- GS > 5 MW: 117

Retail Prices of Electricity

In Ontario, the average retail price of electricity averages between $0.10-$0.13/kWh all-in for a customer's bill. Ontario is on time-of-use rates, with the following pricing structure for the winter period (November 1 – April 30)[2]:



All weekends and holidays are considered off-peak. For the winter period, the on-peak period for pricing coincides with the system peak which occurs in the early morning and evening when the space heating load is highest.

[2] http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity+Prices

In the summer period, the on-peak period for pricing occurs in the afternoon, which also coincides with the system peak, which is driven by space cooling load.

ONTARIO - ENERGY EFFICIENCY PROGRAMMING

Previous Results (Savings, Expenditure, Cost Effectiveness)

Before the current Conservation First Framework (CFF, 2015-2020), Ontario's previous cycle for efficiency programs was from 2011-2014. The following results are summarized for that period[3]:

Program	Net Savings (GWh)	Expenditure
Appliance Retirement	58	Not available
Retailer Coupons	280	Not available
Heating & Cooling Incentive	174	Not available
Home Assistance Program	55	Not available
Other Residential Programs	5	Not available
Total Residential Programs	572	Not available
Retrofit	1,527	Not available
Small Business Lighting	289	Not available
Audit	76	Not available
Process & Systems Upgrade	81	Not available
High Performance New Construction	47	Not available
Energy Managers	117	Not available
Industrial Accelerator Program	69	Not available
Other Business Programs	540	Not available
Total Business Programs	2,746	Not available

Program	TRC	PAC
Consumer	1.3	1.6
Low Income	0.6	0.6
Aboriginal	1.1	1.1
Business	1.3	2.8
Industrial	0.9	1.3
Non-LDC Demand Response	1.6	1.1
Non-LDC Industrial	0.6	0.5

[3] 2011-2014 Conservation Results: http://www.ieso.ca/Documents/2011-2014_Conservation_Results_Report.pdf

Highlights from the results include:

- Retrofit program delivered 46 percent of portfolio savings
- Over 9.9 million energy efficient products incentivized through participating retailers
- Portfolio LUEC: $37/MWh
- Portfolio TRC: 1.2
- Portfolio PAC: 2.1

FUTURE TARGETS

The Conservation First Framework covers the time period from 2015-2020. The province-wide budget for the six years is $2.2 billion, of which LDCs are provided with $1.8 billion. The IESO retains some funds for central services and coordinated program delivery.

For the 2015-2020 period, the total Ontario target is 8.7 TWh. The LDCs have a combined target of 7 TWh. On an annual basis, the total savings target for Ontario is 1.3 percent of sales.

Each LDC is required to complete a CDM plan, which must meet all required cost effectiveness requirements, as well as align with their provided budget and target. A summary table of each LDC's savings targets and budgets is provided below:

LDC Name	Target (GWh)	Budget
Algoma Power Inc.	7.5	$2,107,963
Atikokan Hydro Inc.	1.1	$311,330
Attawapiskat Power Corporation	0.5	$148,832
Bluewater Power Distribution Corporation	62.4	$15,838,687
Brant County Power Inc.	16.0	$4,109,140
Brantford Power Inc.	54.3	$14,048,458
Burlington Hydro Inc.	99.0	$25,825,521
Cambridge and North Dumfries Hydro Inc.	85.0	$21,763,931
Canadian Niagara Power Inc.	28.5	$7,355,555
Centre Wellington Hydro Ltd.	8.7	$2,252,724
Chapleau Public Utilities Corporation	1.0	$298,764
COLLUS PowerStream Corp.	16.9	$4,446,841
Cooperative Hydro Embrun Inc.	1.8	$525,743
E.L.K. Energy Inc.	16.2	$4,273,057
Enersource Hydro Mississauga Inc.	483.3	$122,499,403
Entegrus Powerlines Inc.	56.8	$14,695,867
EnWin Utilities Ltd.	151.3	$38,421,929
Erie Thames Powerlines Corporation	27.6	$7,104,954
Espanola Regional Hydro Distribution Corporation	2.4	$685,489
Essex Powerlines Corporation	31.4	$8,532,573
Festival Hydro Inc.	34.7	$8,768,149
Fort Frances Power Corporation	4.0	$1,109,758
Fort Albany Power Corporation	0.3	$98,990
Greater Sudbury Hydro Inc.	34.7	$9,672,498
Grimsby Power Incorporated	10.9	$2,894,613
Guelph Hydro Electric Systems Inc.	99.0	$24,920,625
Haldimand County Hydro Inc.	19.9	$5,410,280
Halton Hills Hydro Inc.	30.9	$8,387,497

LDC Name	Target (GWh)	Budget
Hearst Power Distribution Company Limited	3.2	$843,903
Horizon Utilities Corporation	330.7	$84,830,304
Hydro 2000 Inc.	1.4	$394,750
Hydro Hawkesbury Inc.	7.9	$2,139,160
Hydro One Brampton Networks Inc.	255.2	$66,798,531
Hydro One Networks Inc.	1,159.0	$321,989,874
Hydro Ottawa Limited	394.5	$105,242,155
Innisfil Hydro Distribution Systems Limited	13.0	$3,680,241
Kenora Hydro Electric Corporation Ltd.	5.3	$1,407,448
Kashechewan Power Corporation	0.5	$155,966
Kingston Hydro Corporation	34.5	$8,674,286
Kitchener-Wilmot Hydro Inc.	105.7	$27,710,719
Lakefront Utilities Inc.	12.2	$3,077,834
Lakeland Power Distribution Ltd.	11.3	$2,970,479
London Hydro Inc.	196.7	$51,192,690
Midland Power Utility Corporation	10.8	$2,739,690
Milton Hydro Distribution Inc.	45.4	$11,911,927
Newmarket-Tay Power Distribution Ltd.	36.2	$9,649,555
Niagara Peninsula Energy Inc.	74.4	$19,056,865
Niagara-on-the-Lake Hydro Inc.	11.7	$2,993,633
Norfolk Power Distribution Inc.	18.9	$5,056,939
North Bay Hydro Distribution Limited	20.3	$5,545,424
Northern Ontario Wires Inc.	4.3	$1,174,934
Oakville Hydro Electricity Distribution Inc.	92.4	$24,575,982
Orangeville Hydro Limited	14.1	$3,705,603
Orillia Power Distribution Corporation	16.6	$4,318,856
Oshawa PUC Networks Inc.	73.0	$19,963,922
Ottawa River Power Corporation	8.7	$2,282,373
Parry Sound Power Corporation	4.5	$1,171,912
Peterborough Distribution Incorporated	37.9	$9,781,455
PowerStream Inc.	535.4	$140,696,240
PUC Distribution Inc.	26.4	$7,440,107
Renfrew Hydro Inc.	4.2	$1,070,574
Rideau St. Lawrence Distribution Inc.	5.0	$1,306,239
Sioux Lookout Hydro Inc.	3.7	$1,016,095
St. Thomas Energy Inc.	17.5	$4,643,532
Thunder Bay Hydro Electricity Distribution Inc.	48.4	$12,927,445
Tillsonburg Hydro Inc.	11.3	$2,881,461
Toronto Hydro-Electric System Limited	1,576.1	$400,296,506
Veridian Connections Inc.	153.0	$40,482,340
Wasaga Distribution Inc.	6.3	$1,814,647
Waterloo North Hydro Inc.	82.4	$21,192,868
Welland Hydro-Electric System Corp.	25.5	$6,584,437
Wellington North Power Inc.	5.9	$1,493,412

LDC Name	Target (GWh)	Budget
West Coast Huron Energy Inc.	8.1	$2,012,404
Westario Power Inc.	23.0	$6,101,269
Whitby Hydro Electric Corporation	58.4	$15,860,460
Woodstock Hydro Services Inc.	23.0	$5,898,316
Ontario LDCs	7,000.0	1,835,264,930.7

INCENTIVE LEVEL SETTING METHODOLOGY

While Ontario does not have a documented incentive level setting methodology, a formal process has been established for all potential program changes and new program proposals. This process covers incentive level changes. All proposed changes and new programs must follow a business case development, review and approval process. Individual LDCs, groups of LDCs, or the official LDC-IESO working groups that oversee program design and delivery can all decide to explore a potential incentive change. The change must get general buy-in from the LDC community and approval from the IESO to proceed to business case development. During the business case development process for an incentive level change, the following considerations have to be addressed:

- Technology Costs
- Technology Savings
- Current and Future Technology Penetration
- Market Structure and Delivery Strategy
- Market Research for Customer and Supply Chain Insight
- Historical Participation and Program Evaluation Insight
- Financial Impact
- Cost Effectiveness Impact
- Program Operations Impact including changes to processes, documents and implementation considerations

The business case, once developed, is reviewed by the relevant LDC-IESO working groups, as well as internal IESO management. The ultimate approval and authorization to proceed is provided by the IESO.

The IESO and the LDCs conduct several activities that support the incentive level setting process:

- Standing market research surveys with residential customers and businesses
- Specific market research projects that assist with incentive level development
- Ongoing channel engagement with key supply chain actors
- Rigorous annual program evaluations that cover both impact and process evaluations
- Ongoing technology and measure research to update the Measures & Assumptions (M&A) list
- Best-practice research from other jurisdictions

The insight, analysis and recommendations from these activities are all inputs into the incentive setting process.

Often, incentive levels are reviewed during the program evaluation or program design process. Program evaluation occurs annually, while program design addresses a gap in the market place or in response to an issue. Ontario does not currently prescribe a frequency for incentive level review for the different programs, but certain programs and delivery strategies have natural review cycles. For example, the retailer program incentive levels are reviewed each year and before each campaign. A key market structure insight to consider is that retailers need six to eight months advance notice for incentive level changes, so analysis and recommendations have to be conducted with this structural issue in mind.

Recently, the Retrofit program approved new incentive levels for the prescriptive lighting track. This process involved reviewing historical participation information; calibrating what the incentive level change would mean for those historical participants; and

analyzing what future impacts would be on uptake, the budget and cost effectiveness based on current and future participation trends.

ONTARIO CORE PROGRAM OFFERINGS (RESIDENTIAL AND BUSINESS)

Currently, the conservation programs in Ontario cover the residential, low income, small business, commercial and industrial, and large industrial sectors. The programs cover financial incentives for energy efficient technologies, energy efficiency and energy management coaching and assistance, assessments and direct install of products for the low income and small business sectors, and various capability building and training initiatives for the supply chain. Ontario has featured rigorous evaluation of the conservation program portfolio for the past five years, and due to program maturity, energy efficiency baselines are moving up. For example, standard efficiency T8s, the foundation of several utility programs are now the baseline for efficiency. Recently, Ontario just released a pay-for-performance framework for LDC funding of Conservation Program delivery, the first of its kind in North America.

Program Name	Program Area	Program Measures	Links
Retailer (Coupons, Instant Rebates)	Residential	This program features prescriptive incentives for qualifying measures, purchased from participating retailers. The incentives are provided at point of purchase. Qualifying measures include LEDs, controls, power strips, pipe wrap etc. The incentives are based on up-front cost to the customer, with program cost effectiveness setting a secondary ceiling. Prior to 2010, incentives were limited to a maximum of 30 percent of the retail price.	https://saveonenergy.ca/Consumer/Programs/Instant-Rebates.aspx
Appliance Retirement	Residential	This program features free pick up and environmentally friendly decommissioning of appliance. Additional incentives were not provided since the program, pilot and barriers analysis determined that biggest barrier to appliance retirement was lack of convenience. The program ended in 2015 due to successful removal of the majority of old, pre-1994 inefficient units. Qualifying equipment included full sized fridges and freezers, with customers given the option of providing window air conditioners and dehumidifiers as secondary equipment.	
Heating & Cooling Incentive	Residential	This program features mail-in or online submission of rebates through participating HVAC contractors for qualifying high efficiency furnaces ($250) and central air conditioners ($250 or $400). The incentives were set based on analyzing the up-front cost difference to the consumer between a standard unit and an efficient unit. Program cost effectiveness set a secondary ceiling, with the program equipment mix (75 percent furnace/25 percent air conditioner) allowing the less cost effective air conditioners to be provided with a higher incentive.	https://saveonenergy.ca/Consumer/Programs/HVAC-Rebates.aspx

Program Name	Program Area	Program Measures	Links
Residential New Construction	Business	This program features both a prescriptive and performance track for incentives. Prescriptive incentives are available for installation of energy efficiency lighting and HVAC equipment. The performance track provides $500 or $1,000 per home for obtaining the appropriate Energuide rating. Incentives were set based on attracting builder to consider program for additional electricity efficiency measures.	
Retrofit Prescriptive	Business	This program features prescriptive incentives for qualifying equipment. Incentive applications are submitted online or through a paper-based approach, and are paid after equipment installation and review of the application. Incentives were set based on upfront cost. The incentives were capped at 50 percent of the total costs. Secondary ceilings for triangulating incentive levels were based on amount of savings delivered and cost effectiveness.	https://saveonenergy.ca/Business/Program-Overviews/Retrofit-for-Commercial/Available-Incentives/Prescriptive.aspx
Retrofit Custom	Business	This program was designed to be for larger projects in the commercial and industrial sector, and to capture any projects that might not fall into the Retrofit prescriptive track. Incentives were set based on kW or kWh savings realized, with lighting savings receiving a lower incentive rate than non-lighting savings to encourage greater penetration of the latter category. The incentives were capped at 50 percent of the total cost. With the recent update, the $/kW incentive rate has been removed. An M&V Plan is required for incentive approval. The incentive rates guarantee measure cost effectiveness for almost all technologies and applications from a program administrator perspective.	https://saveonenergy.ca/Business/Program-Overviews/Retrofit-for-Commercial/Available-Incentives/Custom.aspx
Small Business Lighting	Business	This program is targeted to pursuing lighting efficiency for small business customers (under 100 kW) through a direct install approach. Recently, the incentives for the program were updated to include cost sharing for certain measures that were more expensive on a savings delivered basis. Incentives are based on the lower of the price of the equipment supply and installation, or a prescribed incentive rate per kWh savings. The customer is required to contribute the remaining amount if the incentive rate is the limiting factor. The incentive rate helps guarantee measure cost effectiveness from a program administrator perspective.	https://saveonenergy.ca/Business/Program-Overviews/Small-Business-Lighting-and-AC.aspx

Program Name	Program Area	Program Measures	Links
		The program still features a free lighting assessment audit for the customer.	
Energy Managers		This program provides funding for hiring an Energy Manager for larger commercial or industrial customers. The incentive funding is provided through either a guaranteed salary option or a pay for performance option based on realized savings through the year. The pay for performance stream sets funding at $40/MWh. Energy Managers are provided annual savings targets which help with program cost effectiveness.	https://saveonenergy.ca/Business/Program-Overviews/Energy-Managers.aspx
Process & Systems Upgrade (including Industrial Accelerator Program (IAP) portion)		This program is targeted towards large customers, including transmission-connected customers. The incentive funding is provided based on the lower of three options: a prescribed incentive rate for savings, a 40 percent project cost cap or the incentive required to drop the project to a one year payback. In practice, usually one of the first two options is encountered.	https://saveonenergy.ca/Business/Program-Overviews/Process-and-System-Upgrades.aspx http://www.ieso.ca/Pages/Participate/Industrial-Accelerator-Program/Process-and-Systems.aspx

APPENDIX A-2: ONTARIO GAS (UNION GAS)

The incentive setting methodology and cost effectiveness section was based on secondary research and interview with Union Gas. All other sections are based solely on secondary research performed by CLEAResult.

GEOGRAPHIC DEFINITIONS

Union Gas Limited (Union Gas) and Enbridge Gas Distribution Inc. (Enbridge) are the two primary natural gas utilities in Ontario. Together, they serve close to 3.5 million natural gas customers throughout Ontario.

LOAD AND CONSUMPTION INFORMATION

- Total Number of Customers in Ontario (2014): 3,489,238
- Union Gas: 1,400,536
  - Residential: 1,300,000
  - Commercial and Industrial: 116,000
  - Large Volume: 1,000
- Union Gas Sales in 2014 (General Service, in 10^3 m^3)
  - M1 Rate*: 3,328,692
  - M2 Rate*: 1,284,428
  - 01 Rate*: 1,053,067
  - 10 Rate*: 379,430

*M1 and 01 rates are residential, M2 and 10 rates are commercial. M1 and 01 are for customers who consume less than 50,000 m3 per year. M2 and 10 are for medium - large commercial and small industrial customers who consume greater than 50,000 m4 per year. Most residential customers fit in M1 and 01 but there are some commercial customers in M1 and 01.

Cost Rates

Figure 15: Union Gas' Rates [1]

Area	Residential Rate (cents/m3)	C&I Rate (cents/m3)
Eastern ON	10.8100	10.8100
Fort Francis	10.5266	10.5266
Northern ON	10.7178	10.7178
Northwestern ON	10.6017	10.6017
Southern ON	10.8007	10.8007

[1] Union Gas, "Current natural gas rates," https://www.uniongas.com/residential/rates/current-rates (2016)

Figure 16: Historical Canadian Natural Gas Demand by Sector [2]

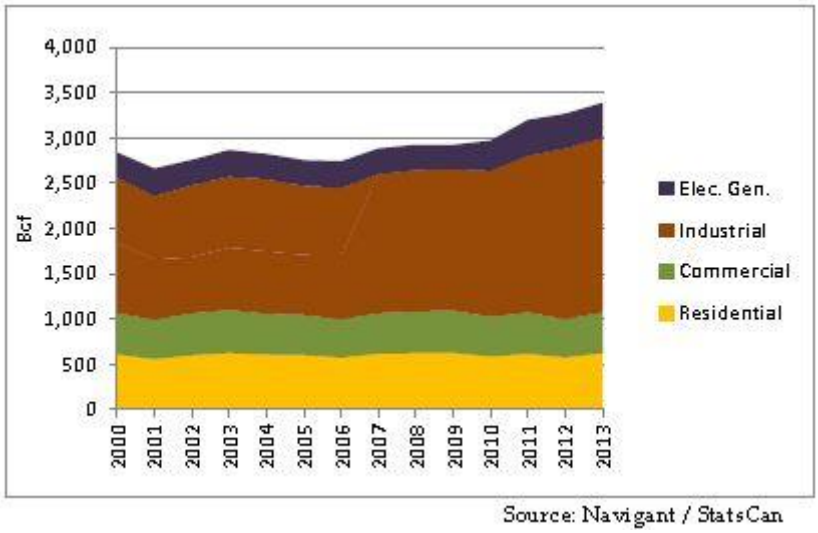
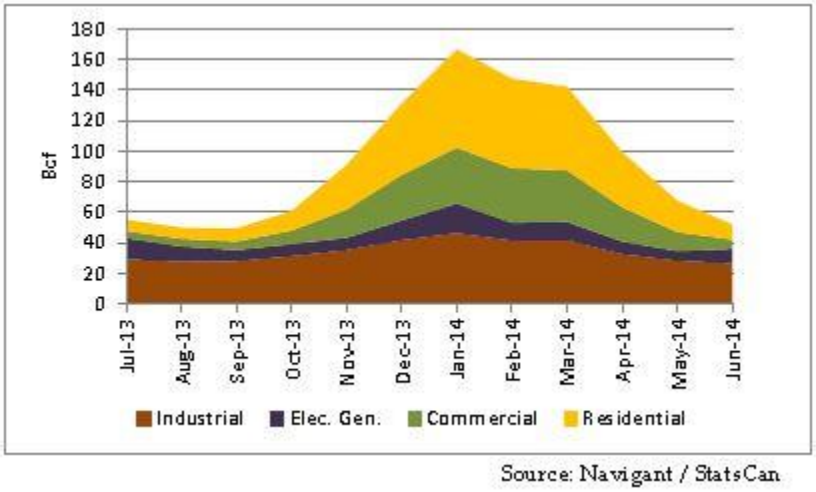


Figure 17: Ontario Monthly Natural Gas Demand by Sector [2]



MARKET STRUCTURE OVERVIEW

DSM is a core part of the conservation first policy in Ontario as per the 2013 Long-Term Energy Plan. In 2014, the Minister of Energy issued a directive to the Ontario Energy Board (OEB) for the development of a new framework for natural gas DSM. The OEB regulates Ontario's natural gas sector and has responsibilities revolving around rates for the transmission and distribution of natural gas.

A part of this directive, the DSM Framework is to enable the achievement of all cost-effective DSM and align closely with electricity Conservation and Demand Management (CDM) efforts as applicable. OEB, along with stakeholders and comments from the public, were to develop this framework with a final version completed in December 2014.

The result is a DSM framework designed to reduce natural gas consumption in Ontario and contains all gas utilities' DSM activities. This includes guiding principles for gas utilities in their design of individual programs, development of DSM strategies

[2] Navigant Consulting Inc., "2014 Natural Gas Market Review Final Report," http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0289/2014_Natural_Gas_Market_Review_Final_Report.pdf (2014)

and for assessing the appropriateness DSM plans for 2015-2020. The framework can also be used in gas utilities' proposal reviews/approvals for their DSM plans by the OEB. Guiding principles include:

1. Invest in DSM where the cost is equal to or lower than capital investments and/or the purchase of natural gas
2. Achieve all cost-effective DSM that result in a reasonable rate impact
3. Where appropriate, coordinate and integrate DSM and electricity CDM efforts to achieve efficiencies
4. Gas utilities will be able to recover costs and lost revenues from DSM programs
5. Design programs so that they achieve high customer participation levels
6. Minimize lost opportunities when implementing energy efficient upgrades
7. Ensure low-income programs are accessible across the province
8. Programs should be designed to pursue long-term energy savings
9. Shareholder incentives will be commensurate with performance and efficient use of funds
10. Ensure DSM is considered in gas utility infrastructure planning at the regional and local levels

For each program developed based on the guiding principles, Union Gas and Enbridge submits participant proposed annual budgets, eligibility criteria, target metrics and shareholder incentives for the OEB's approval. There is a mid-term review in 2018 that intends to establish more specific direction and to assess performance on annual metrics, budget levels, impact on customer rates and shareholder incentives. The utilities will be required to file all completed studies and reports at the mid-term review. These include:

- Infrastructure Resource Planning study
- Natural Gas Conservation Potential study
- Report on free rider reduction efforts and results across all programs
- On-bill presentment status report
- Joint studies and initiatives with electric utilities

The gas utilities are also the administrator of their own programs. Gas utilities are required to provide annual reports to the OEB. The OEB will be leading program evaluation starting in 2016, by hiring the Evaluation Contractor (EC) and chairing the Evaluation Advisory Committee (EAC). The utilities are a member of the EAC.

PORTFOLIO MATURITY AND HISTORICAL PERFORMANCE

DSM of natural gas has been practiced in Ontario for 21 years. The previous DSM Guidelines (EB-2008-0346) were in place from June 2011 regarding development of new multi-year DSM plans for the gas utilities 2012-2014. Prior, the gas utilities were guided by the Decision in the Generic DSM Proceeding in 2006 (EB-2006-0021) from the OEB. The principles and priorities were for gas utilities to follow from 2007-2009.

Figure 18: Total Savings and Costs of Gas Utilities [3]

Year	Annual Savings (m^3)	Costs ($)
2012	137,438,488	31,322,216
2013	179,966,564	32,838,926
2014		30,091,000(Budget)

[3] Ontario Energy Board, Multiple documents from: "Natural Gas Demand Side Management," http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0289/2014_Natural_Gas_Market_Review_Final_Report.pdf (2016)

Figure 19: TRC Ratio in 2012-2013 by Programs [3]

Program Category	TRC Ratio (2012)	TRC Ratio (2013)
Union Gas	3.91	3.83
Residential	5.07	4.4
Commercial/Industrial	3.07	2.01
Low-Income	1.32	0.77
Large Volume	6.33	8.74
Optimum Home	N/A	N/A

CURRENT CYCLE

The gas utilities have developed and submitted their annual DSM program budgets for all proposed programs for OEB approval 2015-2020. The budgets are comprehensive including financial, marketing and communications, administration and staffing requirements and program evaluation. The OEB has approved annual DSM budgets for the 2015-2020 with modifications:

Figure 20: Gas Program Budgets [4]

Approved Annual DSM Budgets

Utility	2014 (Actuals)	2015	2016	2017	2018	2019	2020	2015-2020 Total
Enbridge	$ 32,511,266	$ 37,722,230	$ 56,361,117	$ 62,933,844	$ 67,554,087	$ 66,421,773	$ 67,757,376	$ 358,750,427
Union	$ 33,713,172	$ 33,988,000	$ 56,821,373	$ 58,570,073	$ 63,272,305	$ 63,268,773	$ 64,349,541	$ 340,270,066
Total	$ 66,224,438	$ 71,710,230	$ 113,182,490	$ 121,503,917	$ 130,826,393	$ 129,690,546	$ 132,106,917	$ 699,020,493

Notes:
2014 budgets are actuals while 2015-2020 are approved.
Excludes the maximum annual shareholder incentive of $10.45 million / utility / year.

Figure 21: Gas Program Budgets Incentive/Admin Split [4]

Union Overhead Budgets	2016	2017	2018	2019	2020
Proposed Program Overhead Costs	$10,023,000	$8,342,000	$8,505,000	$8,524,000	$8,542,000
Approved Program Overhead Costs	***$8,747,373***	***$9,696,073***	***$9,868,305***	***$9,901,773***	***$9,919,541***
Proposed Portfolio Overhead Costs	$11,735,000	$6,142,000	$5,642,000	$5,642,000	$5,642,000
Approved Portfolio Overhead Costs	***$11,235,000***	***$5,642,000***	***$5,642,000***	***$5,642,000***	***$5,642,000***
Total Proposed Overhead Costs	$21,758,000	$14,484,000	$14,147,000	$14,166,000	$14,184,000
Total Approved Overhead Costs	***$19,982,373***	***$15,338,073***	***$15,510,305***	***$15,543,773***	***$15,561,541***

Reference: Proposed overhead costs - Union Application, Exhibit A, Tab 3, Schedule 4, Page 6.

The gas utilities have also developed targets for each proposed program 2015-2020. The gas utilities incorporated multiple performance metrics via a weighted scorecard approach that weighs lifetime natural gas savings more highly. It is recognized that the industry and market is to look more broadly at conservation and with other key priorities outside of just savings. The result is the scorecard as seen below.

[4] Ontario Energy Board, "Decision and Order EB-2015-0029/EB-2015-0049," http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/513656/view/Decision_and_Order_Enbridge_Union%20_DSM_20160120.PDF (2016)

Figure 22: Union Gas Scorecard [4]

Union	Resource Acquisition	Low-Income	Large Volume	Market Transformation	Performance-based
Cumulative natural gas savings metric weight	75%	100%	100%	0%	0%
Other metric weight	25%	0%	0%	100%	100%

Union Gas proposed other metrics targeting:

- Participants in the Home Reno Rebate program
- Homes built in the Optimum Home new construction program
- Participants in the RunSmart and Strategic Energy Management programs

Figure 23: Union Gas Targets & Performance Metrics [4]

Resource Acquisition Scorecard

Metric	Units	Weight	2016 Target
Metrics and Targets			
Cumulative Savings	CCM (millions)	75%	1,110
Home Reno Rebate Participants	Homes	25%	3,000

Low Income Scorecard

Metric	Units	Weight	2016 Target
Metrics and Targets			
Single Family Cumulative Savings	CCM (millions)	60%	34
Social & Assisted Multi-Family Cumulative Savings	CCM (millions)	35%	15
Market Rate Multi-Family Cumulative Savings	CCM (millions)	5%	2

Market Transformation Scorecard

Metric	Units	Weight	2016 Target
Metrics and Targets			
Homes built >20% above code	Homes	100%	2015 Actual +20%

Performance Based Scorecard

Metric	Units	Weighting 2016	2017	2018	2019	2020	2016 Target	2017-2018 Targets
Metrics and Targets								
RunSmart Participants	Participants	50%	20%	10%	10%	10%	25	125% of Prior Year Actual
SEM Participants	Participants	50%	20%	10%			3	2+ Prior Year Actual
RunSmart Savings (%)	m3		60%	40%	40%	40%		10% Aggregate Participant Savings
SEM Savings (%)	m3			40%	50%	50%		2018: 5%; 2019-2020: 102% of Prior Year Actual

Figure 24: Union Gas Targets and Budgets [4]

Resource Acquisition - Residential	2016 OEB Approved Budget	2016 OEB Approved CCM Targets	2016 OEB Approved Participant Targets	2017 OEB Approved Budget	2018 OEB Approved Budget	2019 OEB Approved Budget	2020 OEB Approved Budget	Total OEB Approved Budget (2016-2020)
Home Reno Rebate	$ 7,233,000	85,745,550	3,300	$ 9,880,000	$ 12,226,000	$ 12,226,000	$ 12,226,000	$ 53,791,000
Energy Savings Kits (ESK) - *Rejected*	$ -	-		$ -	$ -	$ -	$ -	$ -
Behavioural - *Rejected*	$ -	-		$ -	$ -	$ -	$ -	$ -
Residential Resource Acquisition Program Budget	$ 7,233,000			$ 9,880,000	$ 12,226,000	$ 12,226,000	$ 12,226,000	$ 53,791,000
Residential Overhead (Evaluation & Administration) - Revised	*$ 1,378,657*			*$ 1,488,828*	*$ 1,681,697*	*$ 1,681,697*	*$ 1,681,697*	*$ 7,912,576*
Development and Start-up - Revised	*$ -*			*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Evaluation	*$ 559,000*			*$ 700,000*	*$ 859,000*	*$ 859,000*	*$ 859,000*	*$ 3,845,000*
Administrative costs - Revised	*$ 819,657*			*$ 779,828*	*$ 822,697*	*$ 822,697*	*$ 822,697*	*$ 4,067,576*
Residential Program Total including Overhead	$ 8,611,657	85,745,550		$ 11,368,828	$ 13,907,697	$ 13,907,697	$ 13,907,697	$ 61,703,576
Resource Acquisition - Commercial & Industrial								
Commercial & Industrial Prescriptive	$ 6,755,000	302,055,812		$ 6,763,000	$ 7,486,000	$ 7,149,000	$ 7,149,000	$ 35,302,000
Commercial & Industrial Direct Install - *Revised*	$ 500,000	6,699,181		$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 2,500,000	$ 10,500,000
Commercial & Industrial Custom (Studies & Metering)	$ 7,808,000	819,603,817		$ 7,808,000	$ 7,808,000	$ 7,808,000	$ 7,808,000	$ 39,040,000
Commercial & Industrial Resource Acquisition Program Budget	$ 15,063,000			$ 17,071,000	$ 17,794,000	$ 17,457,000	$ 17,457,000	$ 84,842,000
Commercial & Industrial Overhead - Revised	*$ 4,253,176*			*$ 4,964,334*	*$ 4,931,584*	*$ 4,946,286*	*$ 4,946,286*	*$ 24,041,667*
Evaluation	*$ 180,000*			*$ 180,000*	*$ 180,000*	*$ 180,000*	*$ 180,000*	*$ 945,000*
Administrative costs - Revised	*$ 4,064,176*			*$ 4,775,334*	*$ 4,742,584*	*$ 4,757,286*	*$ 4,757,286*	*$ 23,096,667*
Commercial & Industrial Program Total including Overhead	$ 19,316,176	1,128,358,810		$ 22,035,334	$ 22,725,584	$ 22,403,286	$ 22,403,286	$ 108,883,667
Resource Acquisition Total	**$ 27,927,833**	**1,214,104,360**		**$ 33,404,162**	**$ 36,633,281**	**$ 36,310,983**	**$ 36,310,983**	**$ 170,587,243**
Performance-Based								
RunSmart	$ 297,000	(% savings; no 2016 target)	28	$ 592,000	$ 837,000	$ 582,000	$ 802,000	$ 3,110,000
Strategic Energy Management (SEM)	(budget Included above)	(% savings; no 2016 target)	3	***	***	***	***	***
Performance-Based Program Budget	$ 297,000			$ 592,000	$ 837,000	$ 582,000	$ 802,000	$ 3,110,000
Performance-Based Overhead	*$ 251,000*			*$ 251,000*	*$ 251,000*	*$ 251,000*	*$ 251,000*	*$ 1,255,000*
Evaluation	*$ 35,000*			*$ 35,000*	*$ 35,000*	*$ 35,000*	*$ 35,000*	*$ 175,000*
Administrative costs	*$ 216,000*			*$ 216,000*	*$ 216,000*	*$ 216,000*	*$ 216,000*	*$ 1,080,000*
Performance-Based Total	**$ 548,000**			**$ 843,000**	**$ 1,088,000**	**$ 833,000**	**$ 1,053,000**	**$ 4,365,000**
Low Income								
Home Weatherization - *Revised*	$ 6,335,000	36,049,492		$ 6,136,000	$ 7,495,000	$ 8,063,000	$ 8,374,000	$ 36,403,000
Aboriginal	$ 8,000	N/A		$ 419,000	$ 511,000	$ 456,000	$ 448,000	$ 1,842,000
Furnace End-of-Life	$ 761,000	1,736,856		$ 784,000	$ 924,000	$ 919,000	$ 917,000	$ 4,305,000
Multi-Family	$ 2,651,000	18,855,839		$ 3,359,000	$ 2,984,000	$ 3,031,000	$ 3,573,000	$ 15,598,000
Low Income Program Budget	$ 9,755,000			$ 10,698,000	$ 11,914,000	$ 12,469,000	$ 13,312,000	$ 58,148,000
Low Income Overhead - Revised	*$ 1,652,470*			*$ 1,644,841*	*$ 1,656,954*	*$ 1,675,720*	*$ 1,693,488*	*$ 8,323,473*
Evaluation	*$ 220,128*			*$ 213,015*	*$ 225,948*	*$ 244,982*	*$ 263,008*	*$ 1,167,082*
Administrative costs	*$ 1,432,342*			*$ 1,431,826*	*$ 1,431,006*	*$ 1,430,737*	*$ 1,430,480*	*$ 7,156,391*
Low Income Total	**$ 11,407,470**	**56,642,187**		**$ 12,342,841**	**$ 13,570,954**	**$ 14,144,720**	**$ 15,005,488**	**$ 66,471,473**
Large Volume								
Large Volume - *Revised*	$ 3,150,000	Section 5.29		$ 3,150,000	$ 3,150,000	$ 3,150,000	$ 3,150,000	$ 15,750,000
Large Volume Overhead - Revised	*$ 850,000*			*$ 850,000*	*$ 850,000*	*$ 850,000*	*$ 850,000*	*$ 4,250,000*
Evaluation - Revised	*$ 63,000*			*$ 63,000*	*$ 63,000*	*$ 63,000*	*$ 63,000*	*$ 315,000*
Administrative costs - Revised	*$ 787,000*			*$ 787,000*	*$ 787,000*	*$ 787,000*	*$ 787,000*	*$ 3,935,000*
Large Volume Total	**$ 4,000,000**	**Section 5.29**		**$ 4,000,000**	**$ 4,000,000**	**$ 4,000,000**	**$ 4,000,000**	**$ 20,000,000**
Market Transformation								
			2015 Actuals +					
Optimum Home - *Revised*	$ 841,000		20%	$ 841,000	$ 841,000	$ 841,000	$ 841,000	$ 4,205,000
Commercial Savings By Design - New	$ 500,000		8	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 4,500,000
Program Budget	$ 1,341,000			$ 1,841,000	$ 1,841,000	$ 1,841,000	$ 1,841,000	$ 8,705,000
Market Transformation Overhead - Revised	*$ 362,070*			*$ 497,070*	*$ 497,070*	*$ 497,070*	*$ 497,070*	*$ 2,350,350*
Evaluation - Revised	*$ 26,820*			*$ 36,820*	*$ 36,820*	*$ 36,820*	*$ 36,820*	*$ 174,100*
Administrative costs - Revised	*$ 335,250*			*$ 460,250*	*$ 460,250*	*$ 460,250*	*$ 460,250*	*$ 2,176,250*
Total MT budget	**$ 1,703,070**			**$ 2,338,070**	**$ 2,338,070**	**$ 2,338,070**	**$ 2,338,070**	**$ 11,055,350**
Total Program Budget without Overheads	$ 36,839,000			$ 43,232,000	$ 47,762,000	$ 47,725,000	$ 48,788,000	$ 224,346,000
Total Program Overhead	*$ 8,747,373*			*$ 9,696,073*	*$ 9,868,305*	*$ 9,901,773*	*$ 9,919,541*	*$ 48,133,066*
Total Program Budget with Program-level Overhead	$ 45,586,373			$ 52,928,073	$ 57,630,305	$ 57,626,773	$ 58,707,541	$ 272,479,066
Portfolio-level Overhead - Revised	*$ 11,235,000*			*$ 5,642,000*	*$ 5,642,000*	*$ 5,642,000*	*$ 5,642,000*	*$ 33,803,000*
Research	*$ 1,500,000*			*$ 1,000,000*	*$ 1,000,000*	*$ 1,000,000*	*$ 1,000,000*	
Evaluation	*$ 1,300,000*			*$ 1,300,000*	*$ 1,300,000*	*$ 1,300,000*	*$ 1,300,000*	
Administration	*$ 2,035,000*			*$ 2,842,000*	*$ 2,842,000*	*$ 2,842,000*	*$ 2,842,000*	
Pilots - Revised with Direct Install Pilot Removed	*$ 500,000*			*$ 500,000*	*$ 500,000*	*$ 500,000*	*$ 500,000*	*$ 2,500,000*
DSM Tracking and Reporting System Upgrades	*$ 5,000,000*			*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Total DSM Budget Pre-Inflation	$ 56,821,373			$ 58,570,073	$ 63,272,305	$ 63,268,773	$ 64,349,541	$ 306,282,066
Cumulative Inflation @ 1.68% - Rejected	$ -			$ -	$ -	$ -	$ -	$ -
GRAND TOTAL	$ 56,821,373	1,270,746,547		$ 58,570,073	$ 63,272,305	$ 63,268,773	$ 64,349,541	$ 306,282,066

COST EFFECTIVENESS TESTING

Technical Reference Manual

The EC reviews and proposes updates to the OEB with regards to data within the TRM. This occurs yearly. This review and update includes input assumptions to reflect the findings of the annual DSM evaluation and audit. Additional research may be required to include new technologies to the TRM and improve existing assumptions.

Cost Effectiveness Requirements

The gas utilities' overall DSM goals are to achieve all the cost-effective DSM available in its market. The OEB determined that cost effectiveness should be based on the Total Resource Cost-plus (TRC-plus) test when screening prospective programs.

Low-income programs are screened with the same TRC-plus test as Resource Acquisition programs but have a lower requirement of a minimum of 0.7 while Resource Acquisition programs are to have TRC-plus ratio of at least 1.0.

Market transformation programs and pilots are not held to the same requirement as their goals are to change behaviours throughout the marketplace. These programs are not required to have a cost effectiveness test.

Avoided Supply Cost (Benefits)

Given the differences between Union Gas' and Enbridge's geography, system and customers and such, it is expected the avoided supply cost will be different between the two gas utilities.

Under the TRC-plus test, benefits include:

- Avoided natural gas costs
- Avoided transmission and distribution costs (such as pipelines and storage facilities)
- A 15 percent non-energy benefit adder accounting for other benefits not related to the reduction in natural gas such as environmental, economic and social benefits

Costs

Under the TRC-plus test include:

- Costs incurred by program participants (incremental costs)
- Costs of running the energy efficiency programs (delivery and administration costs)

INCENTIVE RATE SETTING

Union Gas is responsible for setting incentive levels for their programs. Periodic reviews of the appropriateness of incentive levels is conducted and adjustments to financial incentives are made. Below is an overview of the process employed by Union Gas when examining an incentive level for a new measure or proposing a significant change to an existing measure.

1. **Market Research**
   The process starts by performing both primary and secondary market research in order to determine the measure performance metrics and costs. The objective is to determine awareness, barriers and purchase decisions. Market penetration and age of technology is considered as well (e.g. new technology versus widespread solutions).
2. **Technical Reference Manuals**
   The Technical Evaluation Committee approve/deny measures for TRMs which are used for savings and assumptions and enables Union Gas to include solutions in programs. Measures with large savings potential can warrant higher incentive levels.
3. **Benchmarking**
   Union Gas also reviews other jurisdictions and evaluates their measures and incentives relative to what is offered in other territories. The goal is to be relatively similar to other territories in their incentives. Other factors such as Incremental Equipment Costs are investigated.
4. **Incremental Cost Design**
   Based on the market research and technology, Union will attempt to incentivize a portion of the incremental cost determined to motivate customers to implement. Typically, this has fallen between 25-35 percent of incremental costs. Incremental costs for measures with base cases, are calculated by the difference between the measure cost and standard measure cost. For measures without base cases, the incremental cost is taken as the full measure cost.
5. **Incentive Rate Finalized**
   Once the incremental measure cost is finalized, Union Gas will set a standard incentive using the above considerations.

The above process is used for prescriptive measures. For custom measures, a similar process as steps 1-5 is followed but other considers may be evaluated such as customer rate class.

EXISTING MAIN PROGRAMS – UNION GAS [4]

Program Area	Program Name	Description	Incentives	Links
Resource Acquisition	Home Reno Rebate	Program provides an audit of customer homes to identify areas of improvement and also rebates or incentives to perform the recommended improvements.	- Incentives for the audit - Basement Insulation: $450 - $1,000 for insulating 100 percent of the basement (Incentive amount depends on spec) - Exterior Wall Insulation: $1,000 - $1,500 - Attic Insulation: $250 - $500 - Air Sealing: $100 - $150 - Furnace/Boiler: $500 - Water Heater: $200 - Window: $40 per window	https://www.uniongas.com/residential/save-money-energy/rebates-promotions/home-reno
	C&I Prescriptive	Program provides customers rebates for a list of recommended efficient technologies and equipment.	- Check link for list of measures and incentives	https://www.uniongas.com/business/save-money-and-energy/space-heating-programs https://www.uniongas.com/business/save-money-and-energy/water-heating-programs https://www.uniongas.com/business/save-money-and-energy/cooking-programs
	C&I Custom	This program is similar to the above but provides incentives based on overall	- Contract customers: $0.10 up to $100,000	https://www.uniongas.com/busi

		natural gas savings realized by the customer's specific needs.	- General service customers: $0.20 up to $40,000 (Total not to exceed 50 percent of project cost)	ness/save-money-and-energy/engineering-projects
Low-Income	Home Weatherization	Program provides low-income qualified residential customers with a home energy assessment and weatherization at no cost. Customers are also eligible to receive energy efficient showerheads, faucet aerators and a programmable thermostat.	The following at no cost: - Home Energy Assessment - Insulation - Water Saving Products - ProgrammableThermostat	https://www.uniongas.com/residential/save-money-energy/rebates-promotions/weatherization/offer
	Aboriginal	This program combines customers with free natural gas energy efficiency measures installed by Union Gas representatives and carbon monoxide detector at no cost. Also, financial incentive to upgrade existing furnaces.	- No cost for measures and installation - Financial incentives for upgrading furnaces	
	Furnace End-of-Life	Program provides social and assisted housing providers and private market customer financial incentives to upgrade to a 95 percent or higher efficiency rating.	- Financial incentives for upgrading furnaces	
	Multi-family	Program targets customers living in social-housing buildings/privately-owned buildings with a high proportion of low-income residents with measures, audits and education.	- Financial incentives to use towards boilers, ventilation systems, custom measures and window upgrades. Tenants are eligible to receive energy efficient showerheads, faucet aerators, and educational information related to energy conservation	
Performance Based	RunSmart	Program provides smaller commercial and industrial customers with a free on-site building assessment, a report on their energy use and recommendations on how to improve their energy efficiency through operational changes.	- Education, Healthcare, Office, Multi-Unit Residential and Entertainment Commercial Customers has financial rate of: $0.10/m3 to a maximum of $20,000	https://www.uniongas.com/business/save-money-and-energy/engineering-projects

Large Volume	Large Volume	This program provides large volume customers with technical support and customer training along with financial incentives for energy saving projects.	- Check link for details	https://www.uniongas.com/business/save-money-and-energy/engineering-projects
Strategic Energy Management		The Strategic Energy Management is a long-term and deep savings initiative for large customers. The customer's energy will be tracked and measured against their baseline performance for continuous improvements.	Incentives are structured to support initial start-up costs as well as provide incentives for measured energy efficiency improvements over the 5-year participation.	http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/472262/view/

APPENDIX A-3: BRITISH COLUMBIA (BC HYDRO)

GEOGRAPHIC DEFINITIONS

BC Hydro is in British Columbia, Canada. They generate and deliver electricity to 95 percent of the population of the province serving over four million people.

LOAD AND CONSUMPTION INFORMATION

- Peak Demand (2017 Forecast): 11,681 MW
- Consumption (2017 Forecast): 63,238 GWh
  - Residential: 19,761 GWh (31%)
  - Commercial: 17,815 GWh (28%)
  - Industrial: 19,016 GWh (30%)

- Annual Savings Target: 884GWh

Figure 25: Customer Count and Loads[1]

Customers	Count	Electricity Sold 2014 (Gigawatt-Hours)
Residential	1,709,071	17,965
Light Industrial and Commercial	201,812	18,501
Large Industrial	177	13,994
Other	3,489	2,558
Trade	239	50,082
Total	**1,914,788**	**103,100**

In BC Hydro, approximately 90 percent of their customer accounts are residential accounts. The remainder is either commercial or industrial and each represents about one third of the total electricity supplied.[2]

RATE INFORMATION[3]

- Residential Customers: $0.0829/kWh (First 1,350kWh), $0.1243/kWh thereafter
- Small Business: $0.1116/kWh
- Medium Business: $0.1030/kWh (First 14,800kWh), $0.0719/kWh thereafter up to individual baseline
- Large Business: $0.1114/kWh (First 14,800kWh), $0.0536/kWh thereafter up to individual baseline

GENERATING CAPACITY (2015)

- Hydroelectric: 11,440 MW (91%)
- Thermal: 1,069 MW (8.5%)
- Diesel Generation: 59 MW (0.5%)

[1] BC Hydro, "BC Hydro Annual Report 2014," https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-report-2014.pdf (2014)

[2] BC Hydro, "BC Hydro Service Plan 2013/14-2015/16," https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/service-plans/bc-hydro-service-plan.pdf

[3] BC Hydro, "General Service Business Rates," https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/business-rates.html (2016)

MARKET STRUCTURE OVERVIEW

BC Hydro is a provincial Crown corporation. Their mandate is to generate, distribute, purchase and sell electricity. The sole shareholder of BC Hydro is the Province of British Columbia. BC Hydro reports to the Ministry of Energy and Mines (Ministry) with the British Columbia Utilities Commission (BCUC) has their regulator. BCUC's primary responsibility is regulation of natural gas and electricity utilities in the province. They are an independent regulatory agency operating under and administering the Utilities Commission Act.

The Integrated Resource Plan is long-term strategic plan for BC Hydro to address growth in electricity demand over 20 years. The 2007 BC Energy Plan contains policies BC Hydro is to follow. BC Hydro and other utilities that fall within this plan are to pursue and invest in all cost-effective demand side management (DSM). They are encouraged to develop a diversified program portfolio for the benefit of all ratepayers. DSM programs are funded by ratepayers.

The Clean Energy Act also contributes to the 2007 BC Energy Plan providing further guidance to meeting objectives. It sets targets for increased investments in clean and renewable energy, electricity self-sufficiency as well as reduced greenhouse gas emissions. It also directs BC Hydro to have 66 percent of future incremental energy demand be met through conservation by 2020.

The Ministry monitors utilities' progress on DSM and energy efficiency assessing barriers to the cost-effective program implementation. They may also propose regulatory directions to BCUC as required. The Ministry is also involved with assessing if appropriate incentives are available for utilities to identify and pursue cost-effective programs.

PORTFOLIO MATURITY AND HISTORICAL PERFORMANCE

Figure 26: Electricity Savings from Energy Efficiency Programs F2003 - F2007[4]

	Cumulative Electricity Savings (GWh/year)		
F2003	353	358	1%
F2004	610	739	21%
F2005	890	1,147	29%
F2006	1,177	1,391	18%
F2007	1,743	1,879	8%

CURRENT CYCLE

There is a forecast of 10,610 GWh of savings per year and 1,756 MW of savings in 2020. The year 2020 is also the milestone year for the 2007 Energy Plan's conservation target. This is based on the Conservation Potential Review (CPR) conducted in 2006 and 2007. The CPR actually determined a range of 6,200 to 10,800 GWh per year of achievable electricity savings by 2021 impacted by market, government policy and DSM measures. [4]

[4] BC Hydro, "2008 Long-Term Acquisition Plan Appendix K," http://www.bcuc.com/Documents/Proceedings/2008/BCH_LTAP_B-1-1_APPENDICES/Appendix%20K.pdf

Figure 27: Planned Energy Savings in F2020 (GWh/yr)[4]

	Codes and Standards	Rate Structures	Programs	Total
Residential	2,760	980	1,070	4,810
Commercial	500	390	1,480	2,370
Industrial	110	730	2,590	3,430
Total	**3,370**	**2,090**	**5,150**	**10,610**

Figure 28: Planned Capacity Savings in F2020 (MW)[4]

	Codes and Standards	Rate Structures	Programs	Total
Residential	584	217	202	1,003
Commercial	65	63	194	322
Industrial	14	95	321	430
Total	**662**	**375**	**719**	**1,756**

Below is the cumulative rate of annual electricity savings resulting from DSM activities. This includes programs, codes and standards and rate structures.

Figure 29: Cumulative GWh/Year following the 2008 BC Energy Plan[4]

GWH/YEAR	F2008	F2009	F2010	F2011	F2012
Target	295	761	1,700	2,300	3,500
Actual	326	983	1,778	2,348	

BC Hydro has developed annual cumulative targets using the Conservation Potential Review and research related to other DSM tools.[2]

The LTAP 2008 also includes support initiatives in the DSM Plan[4]:

- Codes and standards support
- Public awareness and education
- Community engagement
- Technology innovation
- Indirect and portfolio enabling activities
- Information technology
- Rate structures

INCENTIVE LEVEL-SETTING METHODOLOGY

The following is a rough sketch of what we have seen in other territories.

BC Hydro is responsible for setting incentive levels for their programs and introducing new measures and programs. This is performed through business cases for programs and typically occurs every two to three years. Below is an overview of the process employed by BC Hydro when examining an incentive level for a new measure or proposing a significant change to an existing measure.

1. **Benchmarking**
   BC Hydro reviews other jurisdictions and evaluates their measures and incentives relative to what is offered in other territories. Other factors such as Incremental Equipment Costs are investigated. Benchmarking is usually performed by directly contacting the utility of programs.
2. **Market Research**
   Market research depends on the sector/incentive. It can either be achieved by broad primary research or by one-on-one consultations for larger customers. The objective is to determine awareness, barriers and purchase decisions.
3. **Technical Reference Manuals**
   The engineering team, M&V team, program managers, evaluation group and other in-house BC Hydro resources approve/deny measures for TRMs which are used for savings and assumptions. They enable BC Hydro to include solutions in programs. All proposed incentives go through a governance process for technical and business review.
4. **Incremental Cost Design**
   Based on the market research and technology, BC Hydro will attempt to incentivize a portion of the incremental cost determined to motivate customers to implement. Typically, 50-75 percent of incremental costs have been incented. For "Replace on Burnout" measures, the incremental cost is calculated as the difference between the measure cost and that of the standard measures. For Retrofit/Direct Install measures, the incremental cost is taken as the full measure cost including the price of labour. For larger end uses, it is specific to the project, taking into account technology life left – for instance, a very old pump could be repaired almost indefinitely. An old compressor unit will likely be tossed out.
5. **Incentive Rate Finalized**
   Once the incremental measure cost is finalized, BC Hydro will set a standard incentive using the above considerations. Other considerations include:
   - Interaction with conservation rates
   - Interaction with codes and standards
   - Estimated free-ridership and spillover – for instance, no free ridership might mean that the incentive is too low

COST EFFECTIVENESS REQUIREMENTS

Total Resource Cost (TRC) is used by BC Hydro and the BCUC at the program level to evaluate performance. Programs must have a TRC of 1.0 or greater. There is an expectation of low-income programs. Internally, other cost effectiveness tests are used including utility cost and ratepayer impact measure.

Calculating Cost Effectiveness

Cost effectiveness analysis is performed by looking at the stream of benefits and costs resulting from the DSM investment. Four metrics are calculated for each test:

1. Benefit-cost ratio = PV (benefits) / PV (costs)
2. Net present value (NPV) = PV (benefits) - PV (costs)
3. Gross Levelized cost ($/kWh) = PV (costs) / PV (energy savings)
4. Net Levelized cost ($/kWh)1 = PV (costs – all benefits except for electric energy benefits) / PV (energy savings)

TRC Test

Benefits	Costs
• Avoided electric energy costs • Avoided electric capacity costs • Avoided non-electric fuel costs • Customer non-energy impacts[2]	• Utility program costs • Allocated overhead costs • Customer costs • Partner organization program costs

Utility Test

Benefits	Costs
• Avoided electric energy costs • Avoided electric capacity costs	• Utility program costs • Utility incentive costs • Allocated overhead costs

Non-Participant Test (RIM)

Benefits	Costs
• Avoided electric energy costs • Avoided electric capacity costs	• Utility program costs • Utility incentive costs • Allocated overhead costs • Lost revenues

Participant Test

Benefits	Costs
• Electricity bill savings • Non-electricity bill savings • Utility and partner incentive costs • Customer non-energy impacts	• Customer costs

BC HYDRO PROGRAMS

Program Type	Programs	Details
Residential	Behaviour Program[5]	This program intends to inform and educate residential customers about their electricity consumption and motivate customers to reduce that consumption through behavioural changes in their homes. Customers engage in a one-year challenge in reducing electricity consumption by 10 percent, and receive $50 if successful in addition to the bill savings.
	Lighting Program	This program motivates residential customers to make energy efficient choices in their homes and seasonal lighting to transform the market to include more energy efficient lighting products.
	Renovation Rebate Program[5]	Primarily focused on lowering space heating load, this program is targeted towards electrically heated homes and townhouses with forced-air furnaces. It is followed by a home energy assessment. Based on the recommendations on the assessment, customers choose to complete one or more retrofits to improve energy efficiency in their homes. On average, each participant receives about $1,250 in incentives.
	New Home Program	This program intends to create demand and build homes that are more energy efficient than minimum requirements of the B.C. Building Code. Individual measures vary between sites, but will be measured using the EGNH rating system. On a scale of 0-100, homes that achieve greater than 77 may be branded as Power Smart Silver, rating of 80 or more will be branded as Power Smart Gold. Incentives vary depending on the level of achievement, and incentives are also provided for ENERGY STAR appliance and lighting packages.
	Low Income Program[6]	The Low Income Program provides some low-cost energy savings measures that can easily be installed by a homeowner or tenant. The energy saving package includes CFL lamps, faucet aerators, low-flow showerheads, pipe wrap, caulking, draft proofing materials, outlet gaskets, window film, and a number of additional measures as well as energy saving tips. Further offerings are available and delivered through ECAP. They provide qualified low-income residential account holders with a home energy evaluation, the installation of additional energy saving products such as energy-efficient refrigerators and personalized energy efficiency advice. All services and equipment are provided free of charge.
	Appliances and Electronics (Seasonal)	This program motives customers to purchase ENERGY STAR compliant appliances and electronics. This program will focus on the largest energy consuming and most common appliances and electronics that have an ENERGY STAR label.
Commercial	BC Hydro Leaders in Energy Management	This program provides a range of technologies, but focuses on indoor and outdoor lighting, information technology infrastructure (e.g., data servers), heating, ventilation and air conditioning equipment, refrigeration and building operations. There are a number of tools and resources through the program to support this initiative including: • Business Management: Access tools to help you get started by identifying energy efficiency opportunities in your organization • Asset Management: Apply for funding to support energy efficiency implementation projects • Change Management: Obtain education and training to gain energy efficiency expertise and for participant's employees engaged in the process • Peer and Public Recognition: Celebrate designation and achievements

[5] BC Hydro, "Demand Side Management Milestone Evaluation Summary Report F2013," https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/directive-66-f2013-demand-side-management-milestone-evaluation-summary-report.pdf (February 2014)
[6] BC Hydro, "F2012 Demand Side Management Milestone Evaluation Summary Report," https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/directive-66-f2012-demand-side-management-milestone-evaluation-summary-report.pdf (December 2012)

Program Type	Programs	Details
	High Performance Building	The objective of this program is to acquire energy savings by reducing the energy intensity of new commercial buildings through more efficient design and construction relative to standard practices, and to transform the new commercial building industry to a higher level of energy efficiency. • Whole Building Design: Offers co-funding of energy studies to quantify potential energy savings from integrated design and energy saving measures for the building envelope, lighting and HVAC systems • Energy Efficient Lighting Design: Provides funding for the creation of an energy efficient lighting design and a daylighting study and an incentive for the implementation of approved designs
	Energy Management Assessment (Commercial) Program	This program helps participants to take the first step towards improving energy management practices. It involves: • A diagnostic workshop with senior management • Responding to a series of questions regarding energy management which produces a detailed report that highlights areas of opportunities within your organization • Working together with BC Hydro to provide you with resources to implement recommendations and develop action plans • Conducting a benchmark analysis which ranks your organization against other within your industry • An annual review to track progress
Industrial	Energy Studies & Audits	Energy assessments are given to determine how to use energy and trim costs. Eligibility is based on energy consumption and system size. The types of studies available are: • Customer Site Investigation • Plant-wide Audit • End Use Assessment • Energy Efficiency Feasibility Study
	Project Incentives	• Self-Serve Incentive Program: Industrial customers and facilities that use 500 megawatt-hours or more electricity per year ○ Eligible technologies are: Compressed Air Systems between 40 and 200 horsepower; and/or Industrial Lighting • Distribution: Customers that use more than one gigawatt-hour of electricity per year that will save at least 50 megawatt-hours per year ○ Funding covers all aspects of your project including: design, equipment, installation, disposal and tax • Transmission: Customers that use more than one gigawatt-hour of electricity per year that will save at least 300 megawatt-hours per year ○ Funding covers all aspects of your project including: design, equipment, installation, disposal and tax • New Plant Design: Customers in early stage of planning a new facility or expanding an existing facility, an expectation to increase the power load by five percent or more, and an electricity savings potential of more than 300 megawatt-hours per year
	Strategic Energy Management	• Industrial Energy Manager: Customers with more than 10 gigawatt-hours of electricity consumption per year, must hire an energy manager as a full-time employee ○ 100 percent funding of: energy management consulting services, required training for a new energy manager, on-site Energy Management Assessment • Energy Management Assessment: Must participate in the Strategic Energy Management Program ○ A free three-hour on-site facilitated session provided • Employee Energy Awareness ○ Variety of free materials given to remind, educate, and to introduce new operational procedures

Program Type	Programs	Details
		○ BC Hydro also provides funding to help energy managers deliver on Workplace Conservation Awareness
Others	Sustainable Communities Program	• Community Energy & Emissions Plan (CEEP): Intended for improved energy management and it can be used to foster green economic development in the community • Community Energy Manager (CEM): Funding for a dedicated staff resource within local government to drive sustainable policies and projects that reduce electricity consumption and greenhouse gas emissions within the community • Local Area Plan (LAP): To integrate energy planning and conservation measures into land use planning for a specific area. Funding provided for energy experts to participate on the multidisciplinary planning team and to provide data compilation, analysis and recommendation • Project Implementation (Pilot): Funding to drive energy conservation plans, policies and projects into action
	Business Energy Advisors	A Business Energy Advisor will meet with participants to tour their business and identify energy saving opportunities for both electricity and natural gas. Advisors will also introduce applicable incentives for upgrading to energy efficient technologies to better understand consumption as well as simple energy saving behaviours a business can do.

APPENDIX A-4: CALIFORNIA (PG&E)

BACKGROUND

Efficiency Nova Scotia has contracted CLEAResult to conduct energy conservation and energy efficiency program incentive research. The project covers the following areas:

- Identification of best practices for incentive rate setting from other jurisdictions
- Application to Nova Scotia's market

The goal of the project is to generate a guideline for program incentive setting, which features best practices and considerations. Ultimately, this will be used by Efficiency Nova Scotia to help optimize their energy conservation and efficiency program design and delivery to meet their conservation and environmental protection goals.

To assist with the first part of the project, CLEAResult has identified jurisdictions that are considered best in class for their conservation efforts and program offers. We aim to understand how these jurisdictions set their incentives for their programs. In order to do this, we would require a one-time 30-minute to 1-hour telephone interview with key contact(s) in those jurisdictions.

Regarding publication, the jurisdictional scan will be included in the submission to Efficiency Nova Scotia. It will contain all of the details captured in the interview guide. The key contact(s) will be able to review the final jurisdictional scan document before submission. The final project documents will be included in Efficiency Nova Scotia's submission to the Utility and Review Board (UARB), Nova Scotia's regulatory body, and will be publically available.

OVERVIEW

Jurisdictional Scan	
State/Province	California
Utility/Agency	Pacific Gas & Electric
Fuel	Electricity
Key Contact/Interviewee	Carolyn Weiner Manager, EE Core Products carolyn.weiner@pge.com office: 415-973-2391 cell: 415-852-8663
Consultant	Jonathan Houle

STATE OVERVIEW OF ELECTRICITY MARKET

As the largest U.S. state by population[1], and second largest in terms of energy consumption[2] California has a rich history of providing utility and government sponsored energy efficiency programs to its residential and industrial customer base. Regarding energy efficiency programs, the following are the key stakeholders in utility or agency sponsored energy efficiency and demand management program regulation and delivery:

- California Public Utilities Commission
- Load Serving Entities, specifically the Investor Owned and Publically Owned Utilities
- California Energy Commission
- California ISO

[1] Enchantedlearning.com, http://www.enchantedlearning.com/usa/states/population.shtml

[2] U.S Energy Information Association – Detailed State Data, https://www.eia.gov/electricity/data/state/

Load Serving Entities

California is served by approximately 81 load serving entities (LSEs)[3]. These are broken down as:

- Investor-Owned Utilities - 6
- Electricity Service Providers - 22
- Publicly Owned Utilities - 46
- Rural Electricity Cooperatives - 4
- Community Choice Aggregators - 3

The five largest utilities based on and total electricity consumption (in 2014) were:

1. Southern California Edison Company (SCE)
2. Pacific Gas and Electric Company (PG&E)
3. Los Angeles Department of Water and Power (LADWP)
4. San Diego Gas & Electric (SDG&E)
5. Sacramento Municipal Utility District (SMUD)

Electricity Generation

Figure 1 below highlights the various forms of generation (both in-state and out of state) used to meet California's electricity needs in 2014[4]. Figure 2 highlights the historical trend of installed in-state capacity from 2001 to 2014.[5]

2014 Total System Power in Gigawatt Hours

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix (GWh)	Percent California Power Mix
Coal	1,011	0.5%	-	17,877	18,888	6.4%
Large Hydro	14,052	7.1%	160	2,138	16,350	5.5%
Natural Gas	121,934	61.3%	1	10,151	132,087	44.5%
Nuclear	17,027	8.6%	-	8,193	25,220	8.5%
Oil	46	0.0%	-	-	46	0.0%
Other	16	0.0%	-	-	16	0.0%
Renewables	44,887	22.5%	11,423	3,493	59,803	20.1%
Biomass	6,721	3.4%	762	24	7,507	2.5%
Geothermal	12,186	6.1%	150	694	13,030	4.4%
Small Hydro	2,426	1.2%	361	-	2,787	0.9%
Solar	10,557	5.3%	-	2,009	12,566	4.2%
Wind	12,997	6.5%	10,151	766	23,913	8.1%
Unspecified Sources of Power	N/A	N/A	25,676	18,757	44,433	15.0%
Total	198,973	100.0%	37,261	60,609	296,843	100.0%

Figure 30: California Total System Power 2014

[3] http://energyalmanac.ca.gov/electricity/overview.html

[4] http://energyalmanac.ca.gov/electricity/total_system_power.html

[5] http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html

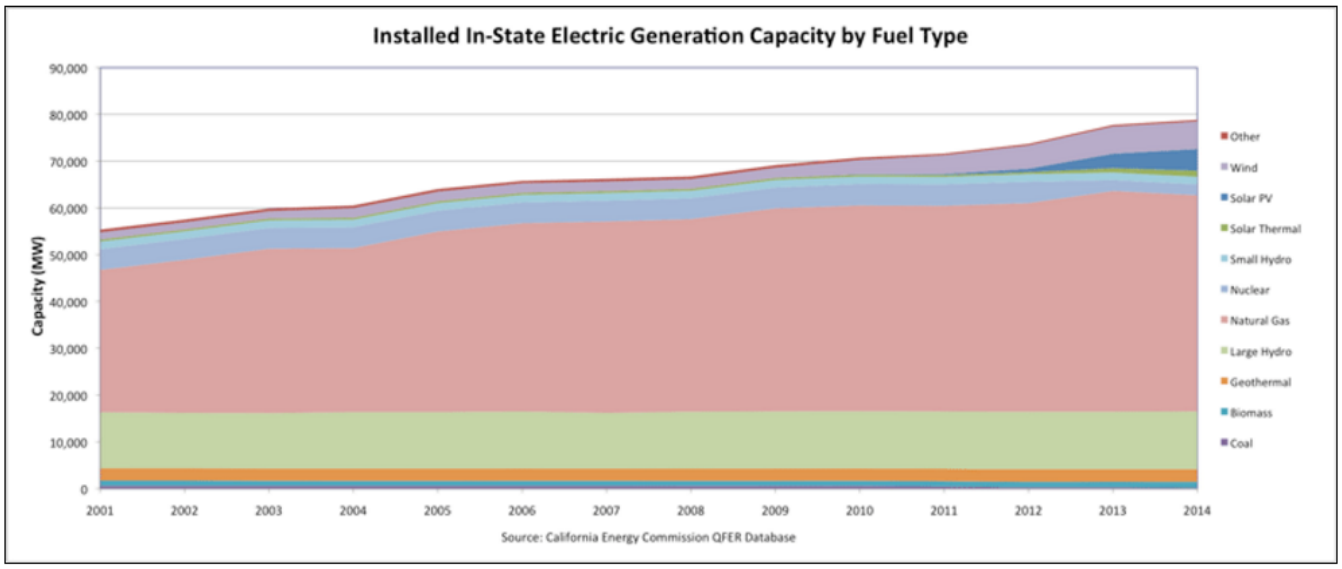


Figure 31: California Total Installed In-State Capacity by Fuel Type

Average Retail Prices[6]

Sector	Retail Rate (cents/kWh)
Residential	16.25
Commercial	15.62
Industrial	12.34

Table 39: Average Retail Rates California - 2014

CALIFORNIA ENERGY EFFICIENCY PROGRAM INCENTIVE & COST EFFECTIVENESS POLICY

California has long been recognized as one of the leading jurisdiction in North America regarding the regulatory standards and policies established to guide the design and delivery of energy efficiency programming. Recently, in order to set annual target and budgets for Program Administrators (PAs), the CPUC moved forward in a proposed decision[7] to create a "Rolling Target" system where long-term targets would be set and updated on an annual basis to include the next year in the long-term forecast. This new rule would require IOUs to submit annual budget to the Commission for approval along with a "business plan" every five years.

While PAs do not have set budget over the term of the forecast, D.14-10-046 has committed to funding roughly $1B in ratepayer funds towards energy efficiency and conservation programs on a go-forward basis.

[6] Energy Information Association, http://www.eia.gov/electricity/state/california/index.cfm
[7] Rulemaking 13-11-005, California Public Utilities Commission, Filed August 18, 2015 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K225/154225993.PDF

Cost Effectiveness Testing

As detailed in D.14-10-046[8], the CPUC has interpreted its mandate to deliver cost-effective energy efficiency and conservation programs as meaning that all energy efficiency portfolios of delivery agents should be cost effective. Within the utility and agency sponsored energy efficiency and conservation community, California's Standard Practice Manual is seen as a benchmark regarding the integration of energy efficiency as a resource and how to use cost effectiveness testing to weigh the contribution of those resources. Programs are evaluated based on Total Resource Cost (TRC) test and the Program Administration Cost (PAC) test.

The Energy Efficiency Policy Manual requires that the energy efficiency portfolio as a whole has higher benefits than costs for both the TRC and PAC tests. The Standard Practice Manual defines the TRC test as the measurement of the net benefits and costs that accrue to society, which is defined as a program administrator (usually a utility) and all of its customers. It compares the benefits, which are the avoided cost of generating electricity and supplying natural gas, with the total costs, which include program administration and customer costs. The TRC does not include the costs of incentives. On the other hand, the PAC test does not include the costs incurred by participating customers but does include incentives paid to participating customers. The PAC test measures the benefits and costs that accrue to the program administrator, which is usually, but not always, the utility.

California uses its DEER database to perform measure level cost effectiveness testing. Additionally, Energy and Environment Economics (E3) has made a portfolio cost effectiveness testing model.

Avoided Costs

Within California, the avoided costs of electricity are generated by E3 for a 20-year period based on the following components: generation energy, generation capacity, ancillary services, transmission and distribution capacity, environment (i.e., avoided greenhouse gases), and the avoided renewable portfolio standard. The avoided cost model is periodically updated to improve the accuracy of how benefits of demand-side resources are calculated. Natural gas avoided costs include: commodity costs, losses, transmission and distribution, and emissions.[9]" The most recent update was completed in 2011.

Please see Table below which details what factors are taken into account when examining each avoided cost component in California:

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward market prices and the $/kWh fixed and variable operating costs of a CCGT	**Historical hourly day-ahead market price shapes from MRTU OASIS**
Generation Capacity	Residual capacity value a new simple-cycle combustion turbine	**Top 250 CAISO hourly system loads**
Ancillary Services	Percentage of Generation Energy value	**Directly linked with energy shape**
T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings	**Hourly temperature data**
Environment	Synapse Mid-Level carbon forecast developed for use in electricity sector IRPs	**Directly linked with energy shape with bounds on the maximum and minimum hourly value**
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource	**Flat across all hours**

Table 40: California Avoided Cost Components

[8] Decision 14-10-046, California Public Utilities Commission, Filed November 14, 2013 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M129/K228/129228024.pdf

[9] Energy and Environmental Economics (E3), Energy Efficiency Avoided Cost 2011 Update, December 2011, https://ethree.com/public_projects/cpuc4.php

PACIFIC GAS & ELECTRIC (PG&E) – UTILITY OVERVIEW

Utility Facts[10]

- Service area stretches from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east
- 141,215 circuit miles of electric distribution lines and 18,616 circuit miles of interconnected transmission lines
- 42,141 miles of natural gas distribution pipelines and 6,438 miles of transportation pipelines
- 5.3 million electric customer accounts
- 4.4 million natural gas customer accounts

Fourth Quarter and full year, 2015 vs. 2014

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2015	2014	2015	2014
Sales from Energy Deliveries (in millions kWh)	21,015	20,944	85,860	86,303
Total Electric Customers at December 31			5,311,178	5,276,025
Total Gas Sales (in Bcf)	226	214	854	870
Total Gas Customers at December 31			4,415,332	4,394,283
Sources of Electric Energy (in millions kWh)				
Total Utility Generation	6,790	7,444	30,372	28,794
Total Purchased Power	12,713	11,496	48,175	52,008
Total Electric Energy Delivered (1)	21,015	20,944	85,860	86,303

Figure 32: PG&E 2015 Annual Report - 2014 vs. 2015 Utility Fact[11]

Customer Class Breakdown

The chart below highlights PG&E's consumption by customer class as identified by California's Energy Consumption Data Management System[12]. The total annual energy consumption in 2014 was 86TWh.

[10] PG&E Company Profile, https://www.pge.com/en/about/company/profile/index.page

[11] http://www.pgecorp.com/news/pdf/2015Q4EarningsSlides.pdf

[12] http://www.ecdms.energy.ca.gov/elecbyutil.aspx

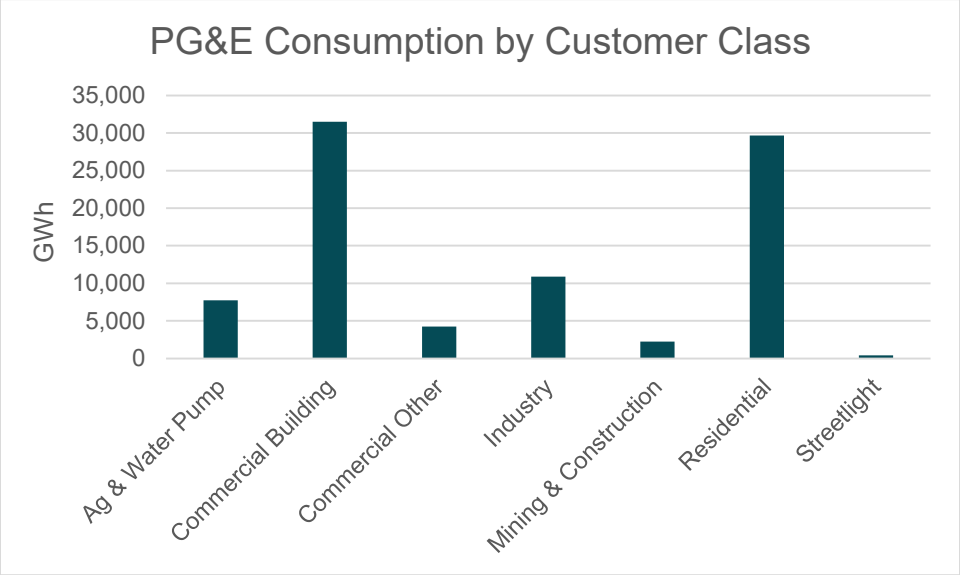


Figure 33: PG&E Consumption by Customer Class

PG&E - ENERGY EFFICIENCY PROGRAMMING

PG&E has been delivering energy efficiency programs to its customers since 1976 having kept more than 168 million metric of CO_2 out of the atmosphere based on cumulative lifecycle gross energy savings. [13]

Savings

PG&E's programs have proven very successful at reducing energy consumption and incentivizing energy efficient behaviours and investment decisions. In the 2013-2015 period, PG&E managed to achieve between 110-143 percent of annual gross energy savings goals and 130-164 percent of annual demand goals delivered through PG&E Programs (excludes Codes & Standards savings).[14]

[13] http://www.pge.com/en/about/environment/pge/energyefficiency/index.page
[14] http://eestats.cpuc.ca.gov/Views/Documents.aspx

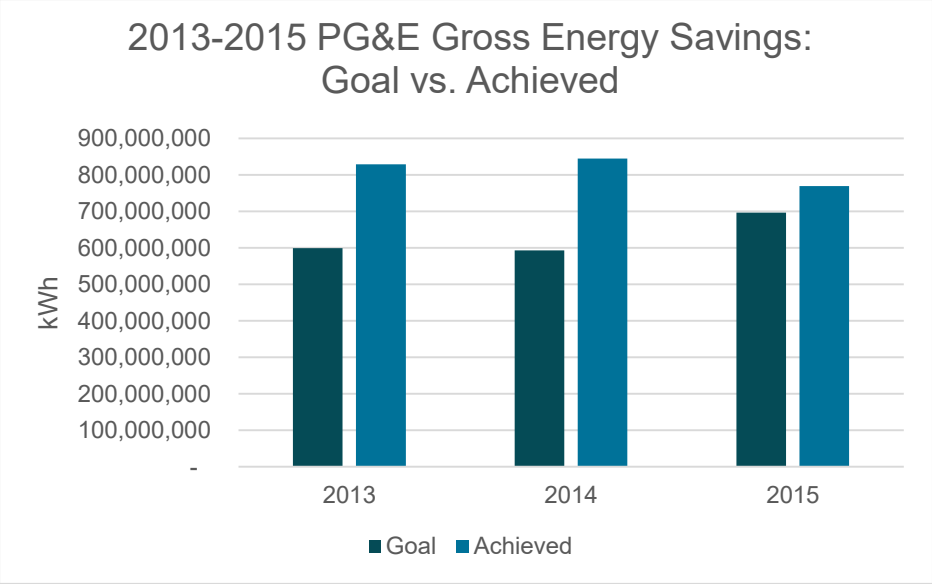


Table 41: PG&E 2013-2015 Gross Energy Savings

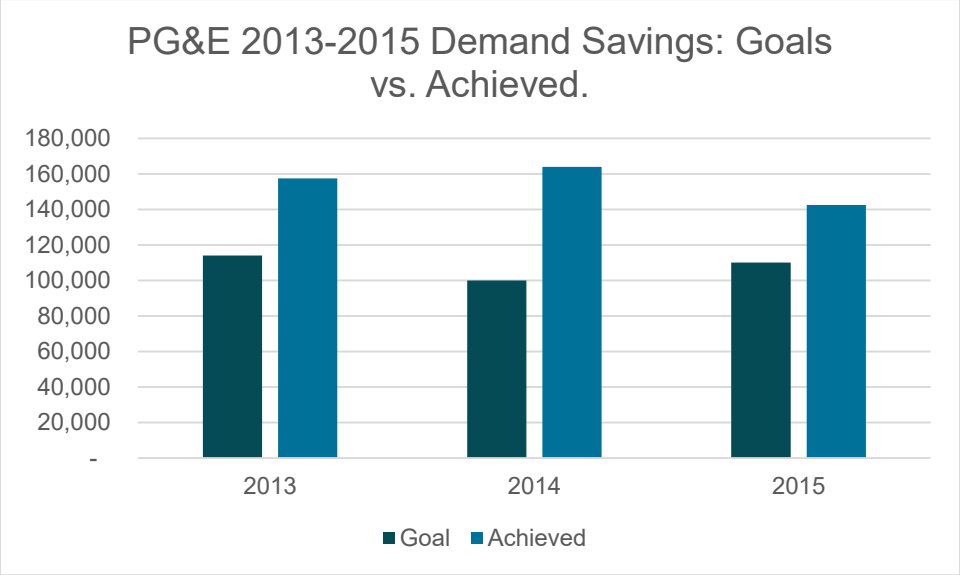


Table 42: PG&E 2013-2015 Demand Savings

Budget & Spending

PG&Es total budget spending on energy efficiency programming (including Codes & Standards funding and On-Bill Financing) achieved through actual expenditures of $1.53B vs. a budget of $1.68B. This is to be commended given PG&E's ability to exceed its targets. The budget specific to energy efficiency programming is as follows:

2013-2015 Total Portfolio $/kWh*			
	2013	**2014**	**2015**
Gross Savings (kWh)	828,999,924	845,181,086	769,529,791
Spending	$ 317,221,372	$ 365,056,021	$ 385,199,846
$/kWh	$ 0.38	$ 0.43	$ 0.50
*Excludes C&S,EM&V and On-Bill Financing expenses reported			
**Budgeted, not actuals			

PG&E 2013-2015 Incentive-to-Administrative Spending Ratios			
	2013	**2014**	**2015**
Incentive	261,270,952	296,147,345	N/A
Administration	$ 55,950,420	$ 68,908,676	N/A
Incentive: Administration Spending Ratio	82:18	81:19	N/A

Cost Effectiveness

All California PAs must deliver energy efficiency portfolios which have a TRC and PAC greater than 1. Below is PG&E's historical cost effectiveness for its 2013 and 2014 program portfolio.

PG&E 2013-2015 Incentive-to-Administrative Spending Ratios			
	2013	**2014**	**2015**
TRC	1.33	1.38	N/A
PAC	2.36	2.18	N/A

FUTURE TARGETS

Below are individual IOU gross annual targets filled to the CPUC in R-13-11-005:

Table 1. Annual GWh

	PG&E			SCE			SDG&E		
Year	IOU Programs	Net C&S[17]	Total	IOU Programs	Net C&S	Total	IOU Programs	Net C&S	Total
2016	625	611	1,236	674	631	1,304	183	143	327
2017	637	506	1,144	694	522	1,216	186	119	305
2018	507	408	916	528	421	949	141	96	237
2019	511	401	912	542	414	955	144	94	238
2020	519	381	900	553	393	946	147	89	236
2021	524	326	850	542	337	879	147	76	223
2022	541	295	836	559	304	863	151	69	220
2023	558	254	812	573	262	835	154	59	214
2024	581	240	821	593	247	840	158	56	214

Figure 34: California IOU Annual GWh Energy Efficiency Targets 2016-2024

Table 2. Annual MW

	PG&E			SCE			SDG&E		
Year	IOU Programs	Net C&S	Total	IOU Programs	Net C&S	Total	IOU Programs	Net C&S	Total
2016	85	141	226	122	145	267	25	33	58
2017	87	105	193	123	108	231	26	25	51
2018	69	103	172	99	106	206	20	24	44
2019	70	103	173	103	107	210	20	24	44
2020	71	101	173	107	104	211	21	24	45
2021	74	94	169	103	97	201	21	22	43
2022	80	90	170	109	92	201	22	21	43
2023	86	84	171	113	87	200	23	20	43
2024	92	82	173	119	84	203	25	19	44

Figure 35: California IOU Annual MW Energy Efficiency Targets 2016-2024

INCENTIVE LEVEL SETTING METHODOLOGY

PG&E's Energy Efficiency Products organization was formed approximately six years ago in part to standardize and streamline the measures developed and marketed through PG&E's breadth of energy efficiency programs. One of the organization's responsibilities is to provide PG&E the resources to actively study market and technology trends (both technologically and

economically) while optimizing PG&E's portfolio of incentivized products based on the technological and market maturity of a measure.

It is important to highlight the regulatory approach for communicating incentive levels to California's Public Utility Commission. The PA's Program Implementation Plans provide incentive levels for each measure offered in that respective program; when a change is made to an incentive level, the PA is required to report that change when it changes more than 50 percent of the reported amount. Historically, the Public Utility Commission may focus on the portfolio cost effectiveness including the total incentive spend for programs as well as other major cost elements like administration, marketing, and other non-incentive implementation costs.

To ensure measure design is properly vetted, PG&E's Products organization has instituted a structured process in which new energy efficiency solutions and services are researched and evaluated for their appropriateness for inclusion in the energy efficiency program portfolio and appropriate incentive levels are defined. This "gated" process ensures that all new and existing technologies are properly vetted by engineering and program staff and are approved on their technical merits (i.e., energy savings potential) by the Commission. Outside of regulatory proceedings this process, named SPARC (Smart Products and Rewards Customers), has been presented to the Commission and is attached in Exhibit A.

Below is an overview of the process employed by PG&E when examining an incentive rate for a new product or proposing a significant change to an existing incentive rate (change in incentive greater than 50 percent). Please note that PG&E uses a streamlined version of the E3 Cost Effectiveness model at each stage in order to calculate preliminary measure level incentives and cost effectiveness to ensure that the incentives will be properly set to achieve the appropriate market transformation goals while maintaining portfolio level cost effectiveness. It is important to note that for PG&E, there is no requirement for individual measures to have a TRC or PAC greater than 1 which allows PG&E to invest in high potential measures and technologies.

1. **Market Research**
   PG&E staff will begin the incentive setting process by performing both primary and secondary market research in order to determine the measure performance metrics and costs. This will include holding interviews with the appropriate manufacturers and distributors to obtain information on their price buildups while also obtaining a sample set of sufficient size to determine the above metrics. These results of manufacturer and distributor interviews are kept confidential in order to protect any competitive information or market intelligence which may have the potential to harm a certain manufacturer or distributor.
2. **Work Paper**
   Once measure level data is acquired from the market, the Products organization will engage its engineering staff to produce a Work Paper. The Work Papers, similar to TRMs found in other jurisdictions, are documents which detail how measure savings are to be calculated including the appropriate EM&V protocols as well as the measure costs. Once completed, the Work Papers are approved by the Commission and the measure is now available to be offered with a PAs program portfolio. It is important to note that the Work Papers do not include any incentive rates as this is determined by the PA and reviewed with the CPUC through Program Implementation Plans.
   The next step in the incentive design is to determine the proposed measure's incremental cost. Generally, PG&E will attempt to incentivize 75-100 percent of the incremental cost of new measure and adjust accordingly as the technology and market penetration matures. For "Replace on Burnout" measures the incremental cost is calculated as the difference between the measure cost and that of the standard measures contained in the building code. For Retrofit/Direct Install measures, the incremental cost is taken as the full measure cost including the price of labor.
3. **Incentive Rate Finalized**
   Once the incremental measure cost is finalized, the Products team will set a standard incentive using the above considerations. Currently, PG&E is attempting to standardize this process in order to cascade the incentive rate not only into PG&E's utility administered programs but as well as third-party programs (3P) administered by outside implementers. The 3Ps have the option to provide "kickers" (increased incentive rates) in order to drive additional market participation in their programs.

For programs where the incentives are not fixed but are based on a $/kWh or $/kW, a similar gated process as the above is employed but is somewhat modified using the following considerations:

- Historical Project Costs: In order to determine the broad project costs, a sample set of historical projects is reviewed.

- Payback Period: PG&E attempts to set the $/kWh or $/kW incentives based on bringing average project payback per category (i.e., lighting vs. non-lighting) to approximately under five years. A product is usually not incentivized should it have a payback greater than 10 years without incentives.
- Targeted vs. Non-Targeted Incentives: The targeted incentives are put in place to try and encourage program participants to implement “deeper” measures/retrofits.
- Cost Effectiveness: Cost effectiveness is only tested at the program level and not the measure level.
- Incentive Update Frequency: The $/kW and $/kWh incentives are not updated as frequently as the fixed incentives within PG&E’s portfolio. The last update was performed approximately three years ago.

APPENDIX A-5: OREGON & WASHINGTON (ENERGY TRUST OF OREGON)

BACKGROUND

Efficiency Nova Scotia has contracted CLEAResult to conduct energy conservation and energy efficiency program incentive research. The project covers the following areas:

- Identification of best practices for incentive rate setting from other jurisdictions
- Application to Nova Scotia's market

The goal of the project is to generate a guideline for program incentive setting, which features best practices and considerations. Ultimately, this will be used by Efficiency Nova Scotia to help optimize their energy conservation and efficiency program design and delivery to meet their conservation and environmental protection goals.

To assist with the first part of the project, CLEAResult has identified jurisdictions that are considered best in class for their conservation efforts and program offers. We aim to understand how these jurisdictions set their incentives for their programs. In order to do this, we would require a one-time 30-minute to 1-hour telephone interview with key contact(s) in those jurisdictions.

Regarding publication, the jurisdictional scan will be included in the submission to Efficiency Nova Scotia. It will contain all of the details captured in the interview guide. The key contact(s) will be able to review the final jurisdictional scan document before submission. The final project documents will be included in Efficiency Nova Scotia's submission to the Utility and Review Board (UARB), Nova Scotia's regulatory body, and will be publically available.

OVERVIEW

Jurisdictional Scan	
State/Province	Oregon, Washington
Utility/Agency	Energy Trust of Oregon
Fuel	Electricity, Natural Gas
Key Contact/Interviewee	Marshall Johnson Residential Sector Manager Marshall.johnson@energytrust.org Office: 503-445-2949
Consultant	Jonathan Houle

OVERVIEW OF ENERGY TRUST OF OREGON UTILITIES & ENERGY MARKETS

The Energy Trust of Oregon serves four utilities which cover two states:

- Portland General Electric (PGE), Oregon – Electricity
- Pacific Power, Oregon – Electricity
- NW Natural, Oregon & Washington – Gas
- Cascade Natural Gas, Oregon– Gas

The Energy Trust is regulated by the Oregon Public Utilities Commission and the Washington Utilities and Transportation Commission. Please note that Cascade Natural Gas and NW Natural also operate their own energy efficiency programs in markets outside of Oregon.

Utility	Description
Cascade Natural Gas[1]	• 272,000 customers in 96 communities ○ 68 in Washington ○ 28 in Oregon ○ 60,000-70,000 of those customers are served by the Energy Trust • 32,000 square miles
NW Natural[2]	• Over 700,000 customers[3] ○ 14,000 miles of distribution and transmission pipeline ○ ~647,000 residential, ~67,000 commercial, ~1,000 industrial • 90% Oregon & 10% Washington ○ In total 100 cities in 18 counties with a population of 3.5 million
Portland General Electric[4]	• Total Population Served: 1,800,000 • Number of retail customers: ○ Residential: 735,502 ○ Commercial: 105,231 ○ Industrial: 260 • Cities Served: 52 • Total GWh delivered: 19,266GWh
Pacific Power (PacifiCorp)	• Customers Total: 1,783,000 ○ Residential: 1,551,000 ○ Commercial: 196,000 ○ Industrial and irrigation: 36,000 • Customers by state ○ Oregon: 562,050 ○ Washington: 128,140 ○ California: 44,732 ○ Utah: 835,232 ○ Wyoming: 138,868 ○ Idaho: 73,871

Please note that not all customers highlighted above are served by the Energy Trust of Oregon as the utilities operate outside of the Energy Trust's service area. In total, the Energy Trust serves approximately 1.5 million customers.

[1] http://www.cngc.com/utility-navigation/about-us

[2] http://www.snl.com/Cache/1001201668.PDF?Y=&O=PDF&D=&fid=1001201668&T=&iid=4057132

[3] http://www.snl.com/Cache/33120620.pdf?IID=4057132&FID=33120620&O=3&OSID=9

[4] https://www.portlandgeneral.com/our-company/pge-at-a-glance/quick-facts

STATE ELECTRICITY GENERATION MIX

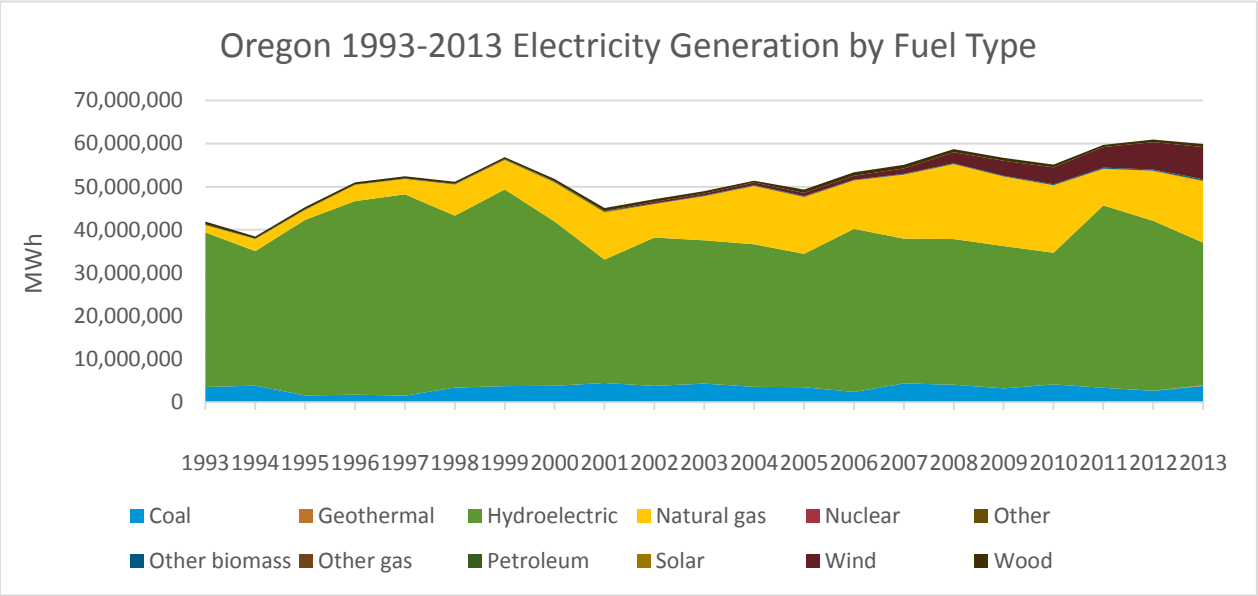


Figure 36: Oregon 1993-2013 Electricity Generation by Fuel Type[5]

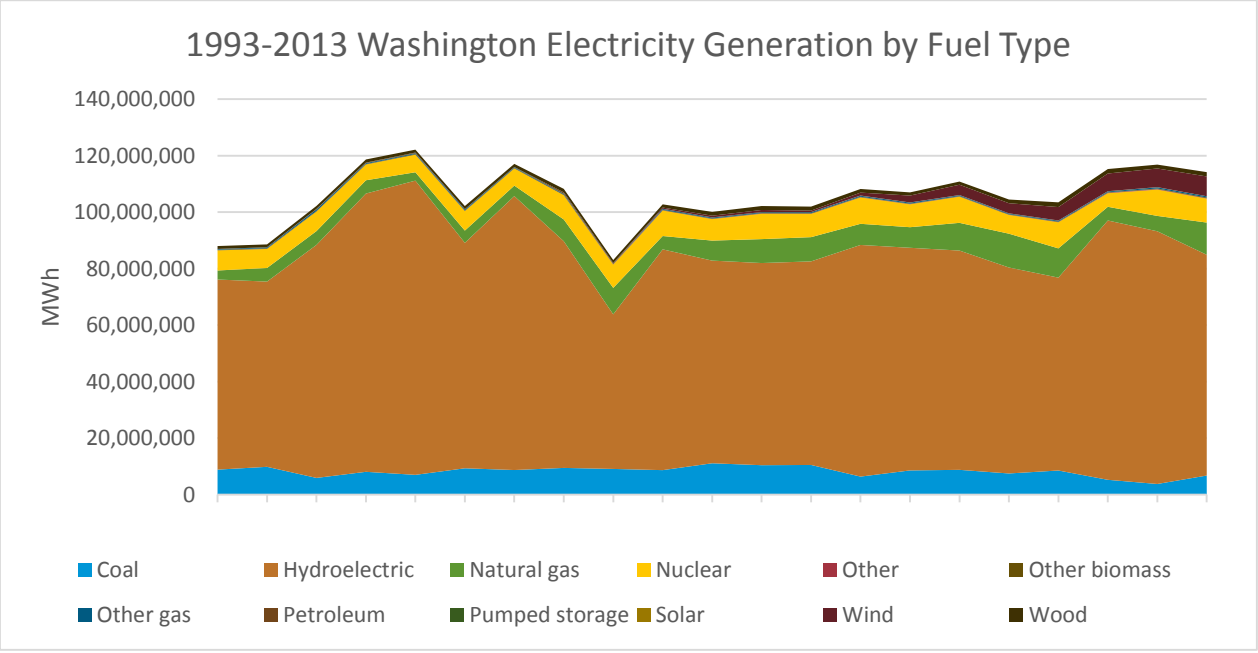


Figure 37: Washington 1993-2013 Electricity Generation by Fuel Type[6]

[5] http://www.eia.gov/electricity/state/oregon/index.cfm
[6] http://www.eia.gov/electricity/state/washington/index.cfm

RETAIL ENERGY RATES

Below are the 2014 electricity rates for Portland General Electric and Pacific Power and the 2014 retail natural gas rates for Oregon and Washington sourced from the U.S. Energy Information Association. These rates are inclusive of transmission and distribution and are in U.S. dollars.

2014 Retail Electricity Rates[7] (cents/kWh)	Portland General Electric	Pacific Power
Residential	11.37	11.09
Commercial	9.14	9.08
Industrial	6.46	7.37

2014 Retail Electricity Rates[8] ($/Mcf)	Oregon	Washington
Residential	11.72	10.59
Commercial	9.44	9.03
Industrial	5.79	8.55

ENERGY TRUST OF OREGON STRUCTURE AND FUNDING[9]

History

In 1999, Oregon lawmakers and citizens envisioned a future with Oregon homes and businesses powered by clean, affordable energy. They established stable, consistent funding to help Oregonians invest in energy efficiency and renewable resources. A new non-profit organization—Energy Trust of Oregon—was created to lead the way.

Energy Trust began operation in March 2002, charged by the Oregon Public Utilities Commission with investing in cost-effective energy efficiency, helping to pay the above-market costs of renewable energy resources, delivering services with low administrative and program support costs and maintaining high levels of customer satisfaction.

Customers of four utilities in two states now fund and directly benefit from Energy Trust programs.

Energy Trust of Oregon Funding

Through state legislation, tariffs and other requirements, Energy Trust is funded by customers of Portland General Electric, Pacific Power, NW Natural and Cascade Natural Gas. Customers of all four utilities pay a dedicated percentage of their utility bills to support a variety of energy-efficiency and renewable energy services and programs.

As a result of a 1999 energy restructuring law, Oregon's two largest electric investor-owned utilities (PGE and Pacific Power) are required to collect a three percent “public purpose charge” from their customers. The funds support:

1. Energy conservation in K-12 schools delivered through school districts
2. Low-income housing energy assistance delivered through Oregon Housing and Community Services
3. Energy efficiency and renewable energy programs for residential and business customers delivered through Energy Trust, an independent, third party approved by the OPUC in 2001

In addition to its work under the 1999 energy restructuring law, Energy Trust administers gas conservation programs for Oregon residential and business customers of NW Natural (as of 2003) and Cascade Natural Gas (as of 2006). In 2009, through an

[7] http://www.eia.gov/electricity/data.cfm#sales

[8] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SOR_a.htm

[9] https://energytrust.org/about/who-we-are/

agreement with NW Natural and the Washington Utilities and Transportation Commission, Energy Trust began serving NW Natural's customers in Washington.

The last piece of Energy Trust funding is separate legislation passed in 2007 that allows PGE and Pacific Power to work with Energy Trust on capturing more low-cost electric efficiency for their customers—avoiding the need to purchase more expensive electricity.

The pace at which Energy Trust energy-efficiency programs delivered savings changed significantly after 2008. In 2013, Energy Trust programs saved twice as much electric energy (58 average megawatts) as they did in 2009 (27 aMW). This doubling in annual savings was made possible by the passage of SB 838, which allowed the electric utilities to supplement funding for electric efficiency beyond the three percent charge established in Energy Trust's enabling legislation, to acquire all cost-effective energy efficiency identified in their long-term planning processes.

Natural gas savings also increased from 2.7 million annual therms in 2009 to 5.3 MMTh in 2013 as Energy Trust programs matured and expanded to address the needs of more customers and closely align with utility long-term planning. Also in 2009 Energy Trust and NW Natural entered into agreements to provide program offerings for a portion of NW Natural industrial demand-side management customers and for NW Natural customers in southwest Washington.

With the passage of SB 838 and the expanded gas efficiency agreements, Energy Trust's goals were set to acquire cost-effective energy efficiency as determined within utility long-term planning. Prior to that, goals were limited by funding and not by opportunity. Achieving this higher level of performance required a focused effort to diversify and refine Energy Trust programs, generate faster feedback from participants on program effectiveness, process more incentives and serve more customers with strategies tailored to meet their needs. It also required a larger annual budget and expenditures, bringing Energy Trust's expenditures for energy efficiency to $117 million in 2013, as compared to $63 million in 2008.[10]

Northwest Power Plan[11]

The Northwest Power & Conservation Council represents the regional power planning efforts of Idaho, Washington, Oregon and Montana. The Northwest Power Act requires that the Council produce a 20-year Power Plan each 5 years. The most recent Plan was released in February 2016. Within the Plan, it identifies energy efficiency as the resource with the least cost, while also avoiding risks of volatile fuel prices, financial risks associated with large-scale resources and also mitigating the risk of carbon reduction policies. Energy efficiency was also identified as contributing significantly to the region's future capacity needs.

Accordingly, the Council has stated that the development of all cost-effective energy efficiency should remain the priority in the region to meet electricity resource needs. The Council has balanced the cost of procuring energy efficiency resources to ratepayers against the cost of future capacity and generation requirements.

ENERGY EFFICIENCY BUDGETS AND TARGETS[12]

Below are the annual budgets and targets presented by the Energy Trust in its Annual Budget and Action Plans referred to below.

	2013	2014	2015	2016
Electricity Efficiency	$125,804,504	$130,262,893	$130,359,188	$141,288,266
Gas Efficiency	$28,471,175	$28,946,948	$23,316,785	$26,347,507
Total	$154,275,679	$159,209,841	$153,675,973	$167,635,773

[10] http://assets.energytrust.org/api/assets/plans/2015-2019_Strategic_Plan0.pdf
[11] https://www.nwcouncil.org/media/7149935/7thplanfinal_chap03_resstrategy.pdf
[12] https://energytrust.org/About/policy-and-reports/Plans.aspx

	2013	2014	2015	2016
Electricity Savings (aMW)	50.3	57.7	53.1	55.1
Natural Gas Savings (MM Therms)	6.0	6.1	5.8	6.0

INCENTIVE-TO-ADMINISTRATION EXPENSE RATIOS

Below are the incentive-to-administration expense ratios by year obtained from the annual approved budgets for the Energy Trust's Annual Budget and Action Plans. The expenses listed are related to energy efficiency. Please note that "administration" in this context refers to both Energy Trust's costs of managing its budget and programs, third party delivery agent costs, marketing, IT and evaluation costs. The incentives include only costs related to providing product incentives or direct services to program participants. (i.e., audits).

	2013	2014	2015	2016
Incentive Costs	$85,792,815	$87,475,385	$81,650,474	$90,618,627
Administration	$68,482,871	$71,734,454	$72,025,504	$77,017,143
Incentive-to-Administration Ratio	56:44	55:45	53:47	65:35

2015-2019 STRATEGIC PLAN[13]

Goal: Acquire all achievable, cost-effective energy efficiency for utility customers

Five-year energy-efficiency goals:

- Between 2015 and 2019, save 240 average megawatts (aMW) of electricity
- Between 2015 and 2019, save 24 million annual therms (MMTh) of natural gas

[13] http://assets.energytrust.org/api/assets/plans/2015-2019_Strategic_Plan0.pdf

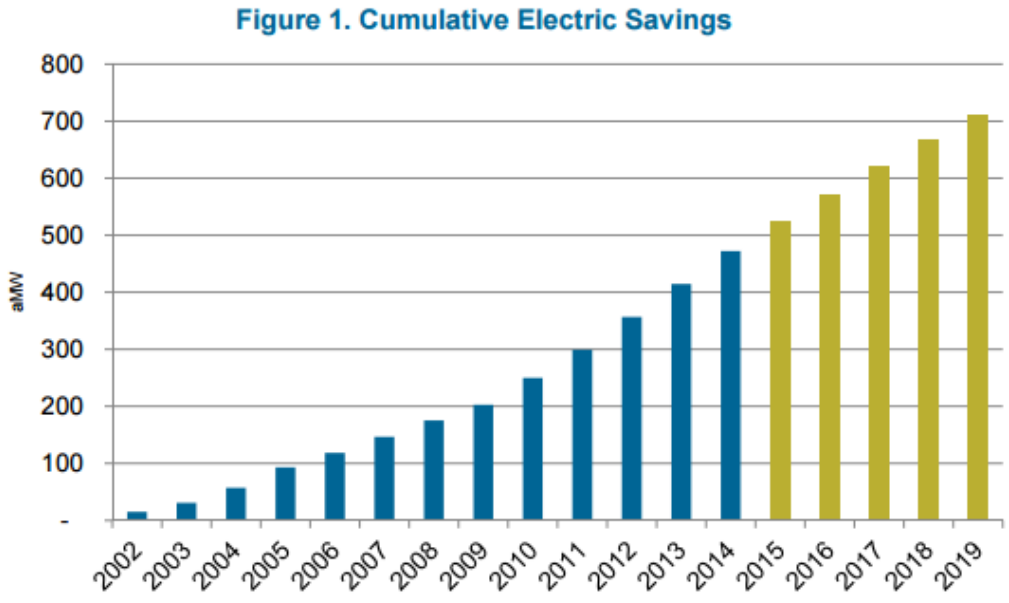


Figure 38: Energy Trust 2015-2019 Cumulative Electric Savings Target

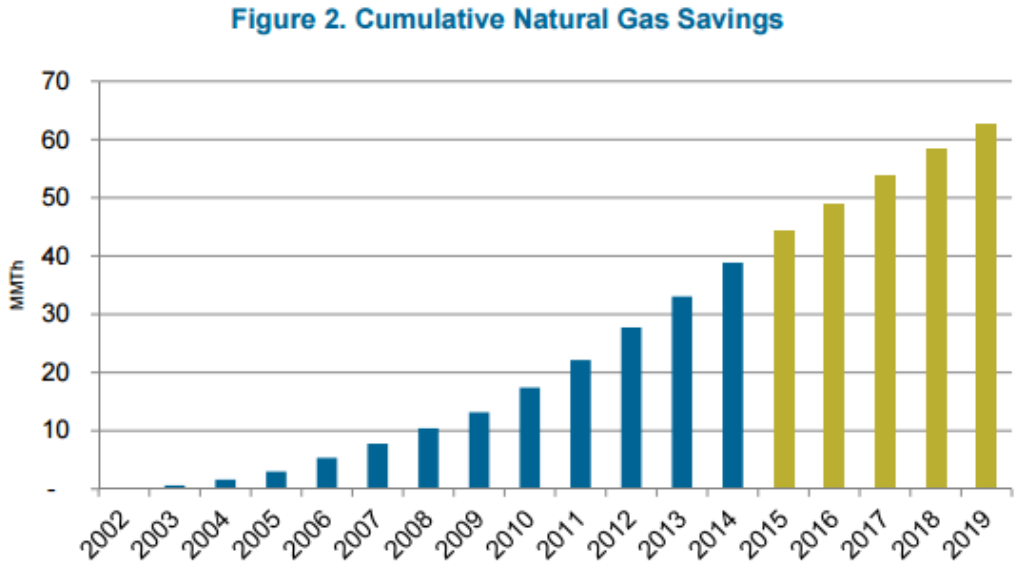


Figure 39: Energy Trust 2015-2019 Cumulative Natural Gas Savings Target

COST EFFECTIVENESS TESTING & AVOIDED COSTS[14]

Cost Effectiveness - Electricity

When evaluating cost effectiveness, the OPUC defined in Docket UM-551 that the following cost effectiveness tests are to be used:

- Utility System Test
- Societal Cost Test (similar to TRC)

Programs and measures that pass both tests (i.e., benefit cost ratio 1.0 or greater), or are likely to over time, are eligible for Energy Trust Investment. Cost effectiveness is used to qualify measures for introduction within the Energy Trust's program portfolio while portfolio level cost effectiveness testing is reported *ex post* to report on portfolio performance.

Costs

The OPUC has defined that the following elements be considered when determining the costs from the societal perspective[15] (i.e., Total Resource Cost):

1. Total cost of efficiency measures and actions[16], including costs to the Energy Trust and participants
2. Energy Trust administrative costs
3. Energy Trust program management costs

The utility system test includes only the Energy Trust incentives and items 2 and 3 above (i.e., all Energy Trust efficiency costs, not those paid by consumers). Costs excluded are the value of Oregon and/or Federal tax credits will be deducted from the cost of measures because similar tax credits are not included in avoided costs used by the Energy Trust. Program administration or management costs of local program that are paid by federal or state agencies will not be included as they are often associated with non-energy consideration such as equity, employment, etc. and are not included in the benefit cost tests under PUC guidance.

Benefits (Avoided Costs)

In the societal test, the Energy Trust will include the following benefits:

1. The value of the electrical and/or gas energy saved based on the avoided cost forecasts of the utilities whose customers are served by the Energy Trust, as reviewed and approved by the PUC.[17] Periodically, the Energy Trust will work with the utilities and PUC to develop an average, or merged cost forecast. This will be done separately for the electric utilities and gas utilities, so that the Energy Trust program decisions are based on a single set of price forecasts for each fuel. The Energy Trust may include factors such as hedge value, if not considered in the utility forecasts, based on agreement with the utilities and PUC.
2. Non-energy benefits will be quantified by a reasonable and practical method. Unless and until the OPUC develops an alternative approach, the Energy Trust may use proxies for these benefits where research shows that the benefits are large, they cannot quantified and they clearly influence consumer decisions.
3. For electricity, both line losses and avoided transmission and distribution construction.
4. Natural gas capacity benefits from reduced transmission and delivery losses will be included where significant and quantifiable.
5. In addition, the Energy Trust will apply in its analysis the 10 percent credit for energy efficiency as required under the Northwest Power Act and OPUC Docket UM-551. This credit recognizes the benefits of conservation in addressing risk and uncertainty.

Avoided costs based on integrated resource planning will be provided to the Energy Trust by utilities. The utility system test will include items 1, 3, 4 and 5 above.

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[14] https://energytrust.org/library/policies/4.06.000.pdf

[15] In Washington, the primary cost/benefit criterion is the societal test, applied to entire programs. In addition to this guidance, the Energy Trust will continue to apply the test to specific measures to assure consistency of program across states and optimal ratepayer value.

[16] For equipment or structures that would be purchased regardless of efficiency actions, this is the Incremental Equipment Cost of upgrading the efficiency of the purchase beyond common practice.

[17] This includes the value of avoided peak energy use.

Currently, utility avoided costs include the forecast value of reduced carbon dioxide emissions. OPUC guidance provides that other environmental pollutant costs may be considered only when specified by the PUC.

Exceptions to Cost Effectiveness for Measure inclusion into programs[18]

For measures which do not pass both the utility and societal (total resource cost) tests, the OPUC does allow measures to be included in programs assuming the measure meets the following conditions as defined in Docket UM-551:

1. The measure produces significant non-quantifiable non-energy benefits. In this case, the incentive payment should be set at no greater than the cost effective limit (defined as the present value of avoided cost plus 10 percent) less the perceived value of bill savings (e.g., two years of bill savings)
2. Inclusion of the measure will increase market acceptance and is expected to lead to reduced cost of the measure
3. The measure is included for consistency with other DSM programs in the region
4. Inclusion of the measure helps to increase participation in a cost-effective program
5. The package of measures is included in a pilot or research project intended to be offered to a limited number of customers
6. The measure is required by law or is consistent with Commission policy and/or direction

Portfolio vs. Measure Level Cost Effectiveness

As mentioned above, cost effectiveness is calculated at both the measure and program levels. It is important to note that there are fundamental differences in what costs are included when testing cost effectiveness at each levels. When performing measure level testing, administration and delivery costs are excluded from the calculation. The reasoning behind this approach is that the costs are, to a large extent, tied to the programs and not dependent on which measures are included. Therefore, the measure level testing only includes the measure's incremental or full costs depending on whether it is a retrofit or replace on burnout or new construction measure.

To counterbalance the measure level testing, the Energy Trust also performs program level testing which includes administration and delivery costs in order to ensure that the total benefits of the savings obtained are greater than the total costs of the programs. Programs are required to achieve a benefit-cost ratio greater than 1 for both UCT and TRC tests.

Historical Cost Effectiveness Results

Below are the cost effectiveness results which were calculated for each program as part of the Energy Trust's 2014 Annual Report.[19]

Program	Utility Cost Test Benefit Cost Ratio	Societal (Total Resource Cost) Test Benefit Cost Ratio
New Homes and Products	2.0	1.7
Existing Homes	2.0	2.5
Existing Building (including Multifamily)	2.5	1.7
New Buildings	3.0	1.9
Production Efficiency	3.5	2.0

[18] http://edocs.puc.state.or.us/efdocs/HAA/um1696haa94619.pdf
[19] http://assets.energytrust.org/api/assets/reports/2014_ETO_Annual_Report.pdf

COST EFFECTIVENESS – NATURAL GAS

The current market condition for natural gas prices (i.e., low price environment) has caused the Energy Trust and PUCs to re-examine gas measures over the last few years. The Energy Trust has been able to call upon Order 94-950 and the exemption conditions listed. In this case, condition 6, whereby a measure is consistent with Commission policy or direction was referenced. The Energy Trust was given relief with measure level cost effectiveness and currently applies the following guidelines:

- Total gas energy efficiency portfolio must have a TRC equal or greater than 1.0
- Measures with a TRC of 0.5-0.9 may receive specific exceptions from the OPUC if Energy Trust requests
- A measure with a TRC less than 0.5 should be removed from the portfolio unless for substantiated reasons

The reasoning behind this approach is that it allows the Energy Trust to maintain its program delivery infrastructure as well as market momentum for the programs until such time that gas prices increase and the portfolio can be grown. By performing cost effectiveness tests at the portfolio level, it allows the Energy Trust to examine the effect of measure with lower cost effectiveness and thus manage program delivery and promotion efforts accordingly.

MEASURE DEVELOPMENT & INCENTIVE SETTING PROCESS

The Energy Trust has created a standardized, four step process (see Appendix A for flow chart) by which to introduce new measures to their product portfolio and set their maximum eligible incentives. The Energy Trust and its program delivery agents can then determine the measure incentives up to the maximum eligible level while balancing the remainder of their delivery and administration expenses required to meet their goals.

Idea Generation & Vetting	Preliminary Measure Development	Detailed Measure Development	Measure Approval
• Identify new measure from multiple souces • Determine if measure addresses the appropriate considerations** • Determine if measure is to be pursued/updated or "parked" for the future	• Collection and analysis of preliminary measure information • Internal Program Lead creates plan to develop measure • Identify if any other program may use measure and identify potential cross-program issues • Preliminary program criteria check and engineering check • If measure is identified as a good fit for current program, it is promoted to the detailed development stage	• Identify technical guidelines and data, identify any data gaps and create research plan for gaps • Stakeholder outreach • Facilitation of cross-program coordination • Cost Effectiveness testing • Draft Measure Approval Document (MAD)** • If measure has sufficient available and reliable data, strong stakeholder interest, cost effective and proper timing and fit it is promoted to approval level • Measures with insufficient data can be piloted	• Finalize MAD • Manager of Planning Engineering published MAD

Considerations for Vetting Ideas, Measures and Measure Updates

Below are the considerations taken by the Energy Trust and its program delivery agents when introducing a new measure into its program portfolio or updating a measure's metrics:

- Savings potential
- Budget impact
- Fit into long-term strategy
- Stakeholder interest
- Risk Analysis with regards to pursuing or not pursuing measure
- Market availability and maturity
- Market acceptance
- Market timing
- Energy Trust previous experience with the measure

Measure Assumptions Document (MAD)

What is a MAD: It is the decision of record determining measure cost effectiveness and authorizing use of a measure. The measure is clearly defined along with the conditions under which it is approved. The MAD provides documentation of all final assumptions used to characterize a measure and determine its cost effectiveness. Variables that are considered key to the savings calculations and cost effectiveness of the measure are highlighted. Any needs for follow up research are listed. While the majority of analysis originates with Energy Trust delivery contractors, all MADs are approved by Energy Trust engineering staff.

A MAD will contain the following sections:

- Valid date: Publication and expiry date
- Scope: Identifying the measure as new, replacement or retrofit
- Program: List of approved programs for which the measure can be used
- Market segment: List of the building types for which the measure can be used (if applicable)
- Description of Measure: Description of the technology and how it saves energy
- Revision History: Describes why changes are being made to the measure (if needed)
- Additional Details
- Cost Effectiveness: The measure's cost effectiveness results along with any exceptions that may have been granted if needed
- Incentive: Lists the maximum measure incentive in the same structure in which it will be incentivized (i.e., $/lamp, $/hp)
- Requirements: Defines the requirements for the measure/project to qualify for incentive (e.g., measure specifications, participation limits and data collection requirements)
- Baseline Conditions
- Savings: Describe what the measure savings are and how they are to be calculated along with the assumptions
- Measure Costs: Includes how to account for the costs (i.e., full vs. incremental) along with sources
- Technological Characteristics: Measure life, load profiles, non-energy benefits, etc.

Incentive Setting Considerations

When setting a measure incentive the following components are some of the key considerations taken by the Energy Trust and their program delivery agents:

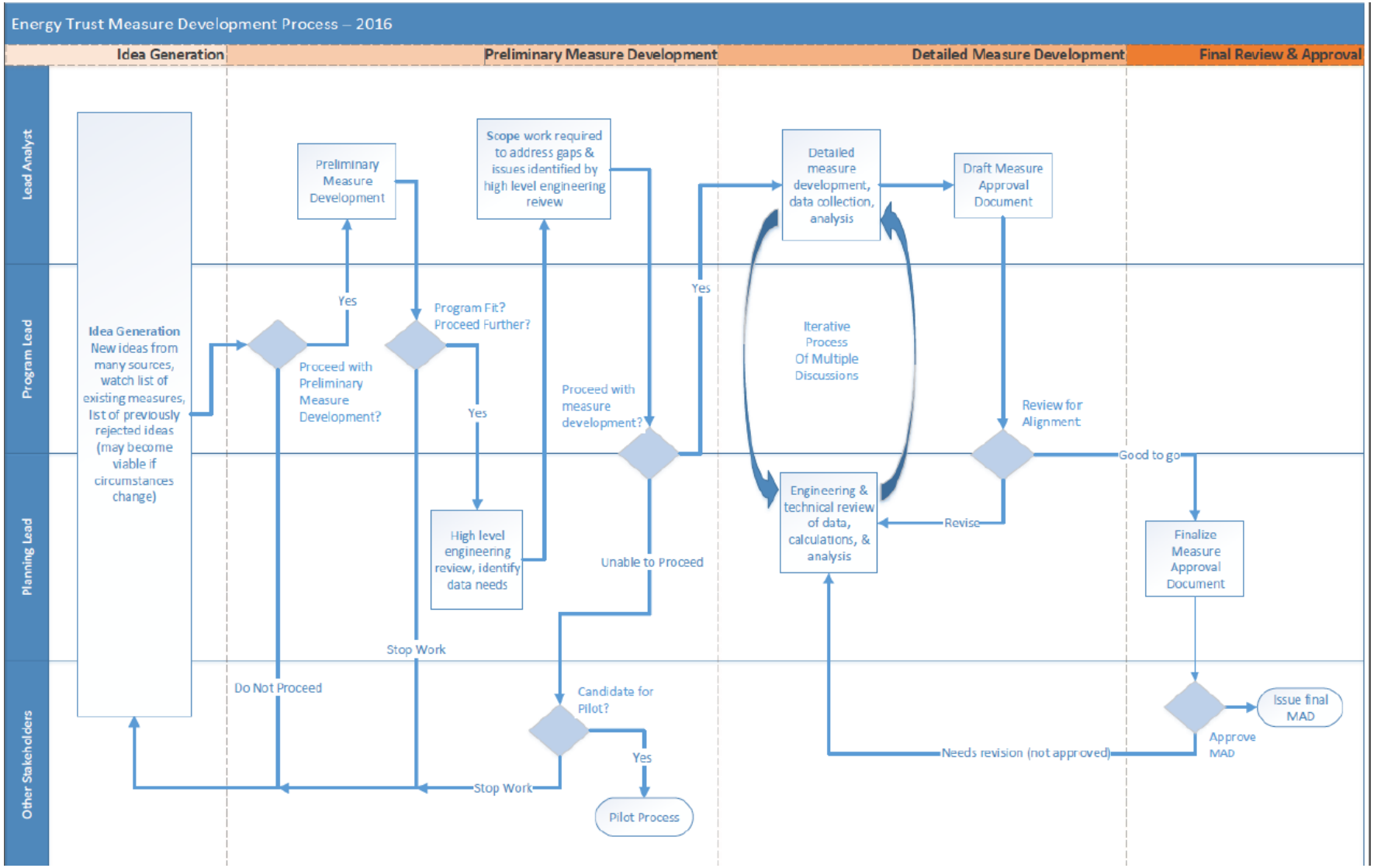
- Relationship of incentive to measure incremental cost
  - The baseline setting process is a key part of properly determining measure incremental costs
- Determination of the incentive's impact on market uptake and barriers
  - The Energy Trust is also mindful of how an incentive will drive participation of distributors with regards to stocking levels
- Total portfolio cost effectiveness and budget
  - The state of the market above will impact the required go-to-market strategy and hence the balance between incentives and program delivery

Overall, it was commented that the process of setting incentives is “more of an art than a science” and determining the ideal incentive for a measure or program is a very difficult if not nearly impossible task. Hence, having a process to update the incentives on a regular basis can be important to adjust incentives as the market evolves and transforms.

It was noted that the Energy Trust has an internal guideline whereby a portfolio’s maximum LUEC must be approximately 3-3.5 cents/kWh for electricity programs and approximately 50 cents/therm for natural gas programs. It is important to note that this is a guideline, the total savings goals are still determined annually by the Commissions. In Oregon, the Commission sets annual performance measure for each utility under the Energy Trust and in 2016, they are 3.4 cents/kWh and 3.5 cents/kWh for PGE and PacifiCorp respectively and 37 cents/therm and 47 cents/therm respectively for Northwest Natural and Cascade.[20] Within the performance measures, the Energy Trust is also evaluated for achieving 85 percent of its 2016 savings goal for each utility and 115 percent of its LUEC target. Lastly, the Energy Trust is also held to a financial performance standard whereby it should target that eight percent of its budget is used to administer the activities of the Energy Trust with the remainder being spent on participant incentives and program delivery agents.

[20] https://energytrust.org/library/forms/2016_OPUC_Performance_Measures.pdf

APPENDIX A: MEASURE DEVELOPMENT PROCESS



APPENDIX A-6: NEW YORK (CONSOLIDATED EDISON)

GEOGRAPHIC DEFINITIONS

Consolidated Edison of New York (Con Ed) is one of the seven large utilities in the state of New York. Con Ed provides service to the downstate markets of New York City and Westchester County.

LOAD AND CONSUMPTION INFORMATION

Peak Demand
- Electricity: 12,316 MW (2015)
- Gas: 1,068 MDt (2016)

Electric Retail Price per kWh in 2014 for Con Ed (In Cents)
- Residential: 28.85
- Commercial: 22.16
- Industrial: 20.18
- Transportation: 17.44

Retail Price per Thousand Cubic Feet in 2015 for New York State (In Dollars)
- Residential: 11.20
- Commercial: 6.89
- Industrial: 8.13 (2014 Price)

State Net Generation (GWh): 11,794
- Nuclear: 4,044 (34%)
- Natural Gas: 3,978 (34%)
- Hydroelectric: 2,270 (19%)
- Coal: 606 (5%)
- Wind: 422 (4%)
- Wood: 32 (0%)
- Petroleum: 254 (2%)
- Other Biomass: 133 (1%)
- Solar: 3 (0%)
- Other: 74 (0%)

NY Electric Utility Net Generation (GWh): 2,639
- Hydroelectric: 1,802 (68%)
- Natural Gas: 746 (28%)
- Petroleum: 112 (4%)
- Coal: 2 (0%)

Figure 40: Electricity Use and Number of Customers[1]

ELECTRIC - (millions of kilowatt-hours)

YEAR	RESIDENTIAL	COMMERCIAL & INDUSTRIAL (C&I)	RAILROADS & RAILWAYS	PUBLIC AUTHORITIES	TOTAL SALES AND DELIVERIES TO FULL-SERVICE CUSTOMERS *	DELIVERY SERVICE FOR ENERGY CHOICE	DELIVERY SERVICE TO NYPA AND OTHERS	SERVICE FOR MUNICIPAL AGENCIES	TOTAL SALES AND DELIVERIES IN FRANCHISE AREA	OFF-SYSTEM AND ESCO SALES
2014	**9,868**	**9,834**	**2**	**53**	**19,757**	**26,221**	**9,951**	**374**	**56,303**	**490**
2013	10,273	9,776	2	67	20,118	26,574	9,846	380	56,918	605
2012	10,718	9,848	2	53	20,621	25,990	10,268	322	57,201	962
2011	11,404	11,148	4	66	22,622	24,234	10,408	562	57,826	691
2010	11,518	12,559	5	60	24,142	23,098	10,834	619	58,693	471
2009	10,952	12,457	6	67	23,482	21,859	10,651	675	56,667	798

ELECTRIC DATA - (average number of customers)

YEAR	RESIDENTIAL	C&I	OTHER	TOTAL	RETAIL CHOICE (Included in Total)
2014	**2,868,468**	**493,466**	**6,148**	**3,368,082**	**896,565**
2013	2,859,556	488,715	6,344	3,354,615	896,266
2012	2,849,583	489,646	6,366	3,345,595	829,260
2011	2,832,772	490,176	6,358	3,329,306	690,163
2010	2,807,492	494,199	6,375	3,308,066	627,642
2009	2,780,685	492,451	4,718	3,277,854	615,197

Figure 41: Gas Use and Number of Customers[1]

GAS - (thousands of dekatherms)

YEAR	RESIDENTIAL	GENERAL	FIRM TRANSPORTATION	TOTAL FIRM SALES AND TRANSPORTATION	INTERRUPTIBLE SALES	DELIVERY SERVICE FOR NYPA AND OTHERS	OFF-SYSTEM SALES	TRANSPORTATION OF CUSTOMER-OWNED GAS	TOTAL SALES AND TRANSPORTATION
2014	**46,661**	**28,969**	**68,731**	**144,361**	**10,498**	**152,560**	**15**	**163,073**	**307,434**
2013	38,872	28,135	61,139	128,146	10,900	136,061	4,638	151,599	279,745
2012	33,457	24,138	52,860	110,455	5,961	156,193	730	162,884	273,339
2011	38,160	26,536	54,291	118,987	10,035	132,056	97	142,188	261,175
2010	37,963	25,629	51,859	115,451	8,521	124,556	7	133,084	248,535
2009	39,749	28,245	48,671	116,665	8,225	124,218	2	132,445	249,110

GAS DATA - (average number of customers)

YEAR	RESIDENTIAL	C&I	OTHER	TOTAL	RETAIL CHOICE (Included in Total)
2014	**942,977**	**122,052**	**4,051**	**1,069,080**	**226,035**
2013	943,925	120,023	4,022	1,067,970	227,599
2012	943,864	119,738	4,000	1,067,602	216,493
2011	942,103	118,824	3,976	1,064,903	182,319
2010	939,220	118,840	3,959	1,062,019	166,702
2009	936,527	117,773	3,955	1,058,255	151,212

MARKET STRUCTURE OVERVIEW

The electric and natural gas Energy Efficiency Portfolio Standard (EEPS) was established in 2008 by the New York State Public Service Commission (the Commission). This initiative is part of the broader State policies for clean energy industry and economy development. Through the EEPS, New York State Energy Research and Development Authority (NYSERDA), as well as the major investor-owned utilities in New York, must provide incentives to homeowners and businesses for energy efficiency improvements. The overall goal is to reduce New Yorkers' electricity usage by 15 percent from the forecasted 2015 level with comparable results in natural gas conservation. This initiative is funded through the ratepayers through the System Benefits Charge (SBC)[2]. The Commission administers this initiative and funds may only be used for programs upon their approval. Utilities are required to report to the Commission annually on programs, budgets and expenditures.

The Evaluation Advisory Group (EAG) exists to advise the Commission and the Department of Public Service (DPS) on statewide evaluation and reporting. The DPS acts as an oversight agency for EEPS program evaluations. The Commission intends for the EAG to act as an advisor to DPS.

NYSERDA's energy efficiency role is the designated administrator of a set of programs separate from the utilities. However, there is some collaborative programs as well. They are funded by the PSC and act like more of a centralized service.

The EEPS was replaced by the Clean Energy Fund (CEF) in February of 2016[3].

[1] Consolidated Edison Inc., "6-Year Financials and Operating Statistics," http://www.google.ca/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0ahUKEwi83d-_0aLMAhVIMz4KHeg8A34QFggbMAA&url=http%3A%2F%2Fphx.corporate-ir.net%2FExternal.File%3Fitem%3DUGFyZW50SUQ9NjA0MjI5fENoaWxkSUQ9MzE1MTkwfFR5cGU9MQ%3D%3D%26t%3D1&usg=AFQjCNFFMp7_hHqqe3xg5LvjnlxhewoUaA&sig2=x7NSjBgK2fQcE3Ov1iJvFw&bvm=bv.119745492,d.cWw

[2] State of New York Public Services Commission, "Order Establishing Energy Efficiency Portfolio Standard and Approving Programs," http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bD9F7E0DF-A518-4199-84CC-C2E03950A28D%7d (June 2008)

[3] State of New York Public Service Commission, "Order Extending Clean Energy Programs," http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0A5494A4-2CD1-4CFE-8BEE-B3E943C04F01%7d (December 2015)

KEY PLAYERS

Electric Utilities[4]:

- Bath Electric, Gas & Water Systems
- Central Hudson Gas & Electric Corp.
- Consolidated Edison Company of New York, Inc.
- Fishers Island Electric Corporation
- City of Jamestown
- Board of Public Utilities
- Town of Massena Electric Department
- New York State Electric & Gas Corp.
- National Grid
- Orange & Rockland Utilities, Inc.
- Pennsylvania Electric Company
- Penn Yan Municipal Utilities Board
- Village of Penn Yan
- City of Plattsburgh
- Plattsburgh Municipal Lighting Department
- Rochester Gas & Electric Corp.
- City of Salamanca Board of Public Utilities
- Village of Akron
- Village of Andover
- Village of Angelica
- Village of Arcade
- Village of Bergen
- Village of Boonville - Municipal Commission of Boonville
- Village of Brocton
- Village of Castile
- Village of Churchville
- Village of Endicott
- Village of Fairport
- Village of Frankfort
- Frankfort Power & Light
- Inc. Village of Freeport
- Freeport Electric
- Village of Green Island
- Village of Greene
- Village of Groton
- Village of Hamilton
- Village of Holley
- Village of Ilion
- Ilion Board of Light Commissioners
- Village of Little Valley
- Municipal Electric Department
- Village of Mohawk
- Mohawk Municipal Commission
- Inc. Village of Philadelphia
- Village of Richmondville
- Village of Rockville Centre

[4] State of New York Public Service Commission, "Electric Utilities Listing," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/03627EFC626529EE85257687006F39CD?OpenDocument

- Village of Rouses Point
- Village of Sherburne
- Village of Silver Spring
- Village of Skaneateles
- Skaneateles Electric Light Department
- Village of Spencerport
- Village of Springville Electric Systems
- Village of Theresa
- Village of Wellsville
- Village of Westfield

Natural Gas Utilities regulated by NYSPSC[5]:

- Bath Electric, Gas & Water System
- Central Hudson Gas & Electric Corporation
- Chautauqua Utilities, Inc.
- Consolidated Edison Company of N Y, Inc.
- Corning Natural Gas Corporation
- Empire State Pipeline
- Filmore Gas Company, Inc.
- Keyspan Energy Delivery (New York)
- Keyspan Energy Delivery (Long Island)
- National Fuel Gas Distribution Corporation
- N.E.A. Cross of New York, Inc.
- New York State Electric & Gas Corporation
- Niagara Mohawk Power Corporation
- Orange and Rockland Utilities, Inc.
- Reserve Gas Company, Inc.
- Rochester Gas & Electric Corporation
- St. Lawrence Gas Company, Inc.
- Valley Energy, Inc.
- Woodhull Municipal Gas Company

The New York Independent System Operator:

The New York Independent System Operator (NYISO) operates the wholesale markets to manage the flow of electricity across the state.

PORTFOLIO MATURITY AND HISTORICAL PERFORMANCE[6]

In the 1980s to 1990s, New York State electric utilities operated large scale energy efficiency programs. The annual spending on these programs was $286 million at its peak in 1992. Total utility spending during 1990-1996 was over $1.2 billion. This resulted in 5,744 GWh of energy savings. The SBC was then established in 1996 with the NYSERDA as the administrator, and utility energy efficiency programs were scaled back. Efforts of New York Power Authority (NYPA), Long Island Power Authority (LIPA) and the Division of Housing and Community Renewal (DHCR) were also present in the market during this period.

[5] State of New York Public Service Commission, "Natural Gas Utilities regulated by NYSPSC," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/AF91A30E4F00289785257687006F3A53?OpenDocument
[6] State of New York Public Service Commission, "Staff Preliminary Proposal for Energy Efficiency Program Design and Delivery," http://www.dps.ny.gov/07M0548/07M0548_EPS_StaffTeamPrelimProposal_FINAL.pdf (August 2007)

Figure 42: NYSERDA Efficiency Programs: Energy Savings and Program Costs: 1998-2009[7]

Year	Cumulative Annual Reductions		Cumulative Annual Peak Non-Curtailable Electric Demand Reductions	Cumulative Peak Curtailable Demand Reductions	Annual Spending
	Electric (GWh)	Other (MMBtu)	(MW)	(MW)	($ Millions)
System Benefits Charge					
1998-2001	399	1,470,403	106	Not available	$ 27.4*
2002	690	3,000,000	218	434	$ 113.7
2003	1,000	2,800,000	270	610	$ 129.3
2004	1,400	2,600,000	325	535	$ 135.5
2005	1,950	4,000,000	445	595	$ 137.5
2006	2,350	4,049,000	495	618	$ 146.1
2007	3,060	4,660,000	650	550	$ 154.0
2008	3,220	5,400,000	700	575	$ 163.8
2009**	3,454	5,250,000	755	590	$ 147.0
Con Edison Gas Funded					
2005	-	-	-	-	$ 0.4
2006	-	-	-	-	$ 1.4
2007	-	134,689	-	-	$ 2.5
2008	-	232,135	-	-	$ 7.3
2009	-	277,740	-	-	$ 10.2
National Fuel Gas Funded					
2008	-	24,778	-	-	$ 1.7
2009	-	59,133	-	-	$ 6.1
National Grid Funded					
2008	-	1,811	-	-	$ 0.18
2009	-	28,229	-	-	$ 2.7
System-Wide Program					
2006	10	-	3	9	$ 3.6
2007	38	-	13	31	$ 17.1
2008	82	-	24	61	$ 5.7
2009 **	83	-	24	67	$ 2.0
Total	3,537	5,615,102	779	657	$ 1,223.18

The figure above summarizes NYSERDA administered programs from 1998- 2008. It also includes three energy efficiency programs that NYSERDA administers on behalf of three utilities: Consolidated Edison, National Fuel Gas, and National Grid.

CURRENT CYCLE

The State of New York's target for electricity use reduction is 15 percent for the 2008-2015 period with similar targets for gas. This target is part of the EEPS divided in two phases. Phase 1 is from 2009-2011 and Phase 2 is from 2012-20152.

[7] "Energy Efficiency Assessment, New York State Energy Plan," http://www.google.ca/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0ahUKEwjE7ZPB9aLMAhUCOj4KHQziBIcQFggiMAA&url=http%3A%2F%2Fenergyplan.ny.gov%2F-%2Fmedia%2Fnysenergyplan%2Ffinal%2FEnergy_Efficiency.pdf&usg=AFQjCNHew5BlRXlfZTubclHm31tEfsN36g&sig2=NHDE3his-pjfp6vRdysS8w (August 2007)

Figure 43: Overall Targets 2007 - 2015[8]

	Energy Efficiency Savings (GWh)								
	2007	2008	2009	2010	2011	2012	2013	2014	2015
Statewide Goals [1]									
New York State 15 x 15 Goals	564	1,471	3,991	7,263	10,631	14,082	17,608	21,222	24,927
NYSERDA SBC III Cumulative State Goals	401	739	1,076	1,413	1,751	2,188	2,626	3,063	3,500
Jurisdictional Gap for the State (EEPS Goals)			833	2,820	4,557	5,563	5,898	6,390	7,687
Con Edison Territory Goals									
NYS PSC Approved EEPS Goals for Con Edison Territory [2]			505	909	1,313	1,717	2,121	2,525	2,828
NYSERDA SBC III Goals for CE Territory [3]	148	273	398	523	648	810	972	1,133	1,295
Total	**148**	**273**	**903**	**1,432**	**1,961**	**2,527**	**3,093**	**3,658**	**4,123**
Energy Efficiency Potential Studies									
Con Edison Energy Efficiency Study 2010 [4]									
Maximum Achievable Potential (MAP)				1,801	3,324	4,784	5,995	6,570	7,061
Realistic Achievable Potential (RAP) (mid)				435	948	1,628	2,355	2,923	3,511
Optimal Energy Efficiency Study 2008 [5]									
MAP			674	1,815	3,400	4,853	6,424	8,081	9,824

Figure 44: Electric Program Budgets[9]

Program Names	C&I Custom Efficiency	C&I Equipment Rebate	Small Business Direct Install	Residential Direct Install	Appliance Bounty	Residential Room Air Conditioning	Residential HVAC	Residential Electric	Multi-family Energy Efficiency
2009	N/A	$54,185,252	$76,702,689	N/A	N/A	N/A	$10,544,823	N/A	$16,589,934
2010	$10,660,000			$3,832,285	$5,659,857	$2,593,500			
2011									
2012	$29,365,716	$144,919,976	$111,567,548	$4,519,285	$5,564,562	$2,739,807	$5,907,497		$29,493,216
2013								$17,741,736	
2014				Discontinued	Three programs combined into Residential Electric Program.				
2015									

Figure 45: Gas Program Budgets[9]

Program Names	Residential HVAC	Multifamily Low-Income	Multifamily Energy Efficiency	C&I Gas Efficient Equipment Rebate	C&I Custom Gas Efficiency
2009	$7,006,015	$2,671,200	$13,469,308	$5,595,624	N/A
2010					$3,046,588
2011					
2012	$8,066,906	$4,748,800	$25,945,436	$12,790,000	$6,963,628
2013					
2014					
2015					

[8] Global Energy Partners, LLC, "Energy Efficiency Potential Study for Consolidated Edison Company of New York, Inc. Volume 1: Executive Summary," http://www.coned.com/documents/Volume_1_Executive_Summary.pdf (June 2010)
[9] State of New York Public Service Commission, "Energy Efficiency Portfolio Standard," http://documents.dps.ny.gov/public/EEPS/EEPSSearch.aspx?SearchType=PRG&PA=2&ProgramType=Gas&ProgramStatus=Open,Closed&SectorSubsector=2:3,1~3:2,1~1:2,1

Figure 46: Electric Savings Result[9]

Program Names (Savings in MWh)	Accumulated Savings to Year	C&I Custom Efficiency	C&I Equipment Rebate	Small Business Direct Install	Residential Direct Install	Appliance Bounty	Residential Room Air Conditioning	Residential HVAC	Residential Electric	Multi-family Energy Efficiency
2009	765	N/A	186,784 (57%)	480,021 (92%)	N/A	N/A	N/A	6,444 (87%)	N/A	58,021 (125%)
2010	62,398	111,506 (167%)			2,633 (18%)	17,402 (53%)	3,213 (40%)			
2011	227,910									
2012	405,083									
2013	565,842								35,181 (102%)	
2014	765,003				Discontinued	Three programs combined into Residential Electric Program. Targets remain the same				
2015	903,087 (85%) *Up to September									

Figure 47: Gas Savings Results[9]

Program Names (Targets in Dth)	Target to Date	Residential HVAC	Multifamily Low-Income	Multifamily Energy Efficiency	C&I Gas Efficient Equipment Rebate	C&I Custom Gas Efficiency
2009	31,772	203,911	90,232	779,336	304,595	202,614
2010	48,589					
2011	406,013					
2012	519,379					
2013	852,363					
2014	1,251,943					
2015	1,399,660 *Up to September 2015					

Program Names (Savings in Dth)	Total Cumulative Savings	Residential HVAC	Multifamily Low-Income	Multifamily Energy Efficiency	C&I Gas Efficient Equipment Rebate	C&I Custom Gas Efficiency
2009	97	159,415 (78%)	73,442 (81%)	649,881 (83%)	278,759 (92%)	81,788 (40%)
2010	22,582					
2011	190,779					

Program Names (Savings in Dth)	Total Cumulative Savings	Residential HVAC	Multifamily Low-Income	Multifamily Energy Efficiency	C&I Gas Efficient Equipment Rebate	C&I Custom Gas Efficiency
2012	413,892					
2013	659,338					
2014	935,548					
2015 (Up to September)	1,102,401 (79%)					

COST EFFECTIVENESS TESTING

Estimated Energy Savings

The Commission approves a series of technical manuals to provide a standard measure-specific approach to estimate the energy and demand savings.

Cost Effectiveness Requirements

Cost effectiveness is evaluated at the program level by TRC. Fast track programs that were implemented early in the cycle had to score well above a TRC of 1.0. This was done to ensure that significant energy savings would result accounting for margins of error.

Avoided Supply Costs in TRC Calculation

The benefits calculated in the TRC are the avoided supply costs. The avoided supply costs include the reduction in costs of electric energy, natural gas, generation and transmission, and distribution capacity, valued at marginal cost for the periods when there is a load reduction.

Costs in TRC Calculation

The costs calculated in the TRC are costs paid by the program administrators and participants plus the increase in supply costs for any period when load is increased.

INCENTIVE RATE SETTING[2]

The incentive setting process involves collaborative discussions between the utilities, NYSERDA and other interested stakeholders. The goal is to achieve statewide uniformity in terms of qualifying technology and incentive levels. However, program designs and measures are still catered to the needs of individual utilities' customers.

EXISTING PROGRAMS

The following are programs a part of the EEPS. Major changes are expected when the CEF portfolio is introduced.

Program Analysis

Initiatives	Target Market	Incentive Setting Methodology
Residential Electric	Residential customers looking to upgrade HVAC, water heater, or	Rebate for HVAC systems, electric heat pump water heater, and programmable thermostat. Incentive amount set depending on efficiency.

Initiatives	Target Market	Incentive Setting Methodology
Rebate (Electric)	install programmable thermostats.	https://www.conedhvacrebates.com/assets/pdf/CE_Resi_Elec_Rebate_App_WRITEABLE.pdf
Residential Gas Rebate (Gas)	Residential customers looking to upgrade HVAC, water heater, or install programmable thermostats.	Rebate for water heaters, boilers, furnace, controls and programmable thermostat. Incentive amount set depending on efficiency. https://www.conedhvacrebates.com/assets/pdf/CE_Resi_Gas_Rebate_App_WRITEABLE.pdf
Residential Bounty (Electric)	Residential customers looking to upgrade to a more energy efficient freezer or refrigerator. Also, rebates available to customers with old window or wall or air conditioning units.	Rebate of $50 for freezer and refrigerators. Rebate of $25 for window, wall, and air conditioning units. http://www.coned.com/energyefficiency/residential_bounty_program.asp
Central Air-Conditioning (Electric)	Residential or business customers looking to add a thermostat to their property. Residential customers who already own a smart thermostat.	Get a free thermostat ($400 value), and $25 thank you cheque for residential customers, or $50 for business customers. $85 if there is already an existing smart thermostat (residential). http://www.coned.com/energyefficiency/residential_directloadcontrol_program.asp
Residential Rebate (Electric)	Residential customers looking to upgrade to more energy efficient appliances.	Appliance rebate up to $75 available on refrigerators, dishwashers, clothes washer, and dehumidifier. Rebate amount depends on efficiency. https://www.conedhvacrebates.com/assets/pdf/CE_Resi_Appliance_Rebate_App_WRITEABLE.pdf
Bring Your Own Thermostat (Electric)	For residential customers who have already purchased a qualifying thermostat, that are willing to participate in a two year air-conditioner adjustment program.	$85 given with an agreement of participating in the two year program. http://www.coned.com/energyefficiency/bring_your_own_thermostat.asp
Small Business Direct Install (Electric)	Small business looking to save money and energy. http://www.coned.com/energyefficiency/businessdirect.asp	Free on-site energy efficiency survey, then have energy-saving lighting or refrigeration equipment installed. ConEd will pay up to 70% of the cost directly to the contractor. Business only pays the difference. http://www.coned.com/energyefficiency/businessdirect.asp
Neighborhood (Electric)	Delivers energy-saving and management solutions to local communities where the demand for electricity is expected to grow significantly because of the vitality in businesses and housing markets. Con Edison provides special incentives and opportunities in the neighborhoods that form part of our Neighborhood Program. Each program is constructed from groups of neighborhoods and each will have its own specific incentives and	Existing neighborhood initiatives includes free lighting, water heating and refrigeration products for small businesses and free lighting products free for apartment buildings. There is also a NYSERDA partnership for combined heat and power (CHP). Con Edison will match NYSERDA's (PON 2568) base incentive up to $1,800/kW (or 100 percent of the project cost, whichever is less). http://www.coned.com/energyefficiency/Neighborhood_program.asp

Initiatives	Target Market	Incentive Setting Methodology
	opportunities based on Con Edison's operational needs in those specific areas.	
Multi-family Energy Efficiency (Electric and Gas)	Customers that own/manage a multifamily building looking to make their property more energy-efficient.	Free in-unit direct installation, free common area direction installation, custom measures at $0.25 per kWh saved, or $2 per therm saved. Set incentive rates available for lighting upgrades in common areas, as well as boilers, radiator valves, insulation, building envelope, and energy management systems. http://www.coned.com/energyefficiency/multifamily-rebates.asp
Commercial and Industrial Prescriptive Rebates (Electric and Gas)	Prescriptive rebates available to C&I customers looking to upgrade their equipment.	Rebates for lighting and controls http://cdn.platform.honestbuildings.com/wp-content/uploads/sites/5/2016/02/Lighting-and-LEDs_v14.pdf HVAC, furnaces, boilers and chillers http://cdn.platform.honestbuildings.com/wp-content/uploads/sites/5/2015/12/HVAC-Furnaces-Boilers-and-other-Gas_v9.pdf Motors http://cdn.platform.honestbuildings.com/wp-content/uploads/sites/5/2015/12/Motors_v5.pdf VFDs http://cdn.platform.honestbuildings.com/wp-content/uploads/sites/5/2015/12/VFDs_v7.pdf All C&I projects capped at 50% or $250,000 for electric and $100,00 for gas for HVAC and VFD projects, whichever is less. TRC test is required and the benefit must be greater than costs.
Commercial and Industrial Performance Based Incentives (Electric and Gas)	Performance incentives available to C&I customers looking to upgrade their equipment that are not listed on prescriptive measures.	All C&I custom measures incented at $0.16 per kWh. Additional bonus incentives on super-efficient chillers. Gas incentive also available at $1-2 per therm. http://cdn.platform.honestbuildings.com/wp-content/uploads/sites/5/2016/03/Custom_v7.pdf All C&I projects capped at 50% or $250,000, whichever is less. TRC test is required and the benefit must be greater than costs.
Commercial and Industrial Energy Study (Electric and Gas)	C&I customers looking for energy saving opportunities.	Energy efficiency studies funded at $50,000 maximum or up to 50% for electric or gas. Incentive at $67,000 maximum for combined studies. Pre-approval is required. http://cdn.platform.honestbuildings.com/wp-content/uploads/sites/5/2015/12/EE-Study_v4.pdf

APPENDIX A-7: NEW YORK (NYSERDA)

SUMMARY

Jurisdictional Scan	
State/Province	New York
Utility/Agency	New York State Energy Research and Development Authority (NYSERDA)
Fuel	Electricity
Key Contact/Interviewee	Matthew Brown
Consultant	Mayuran Srikantha

JURISDICTION OVERVIEW

Electricity Market

The following entities are the key players in the electricity system in Ontario.

- New York Department of Public Service (Public Service Commission)
- New York State Energy Research and Development Authority (NYSERDA)
- New York Independent System Operator (NY-ISO)
- Electricity Utilities

New York Public Service Commission

The New York Public Service Commission regulates and oversees the electric, gas, water and telecommunication industries, as part of the Department of Public Service. In 2015, the Public Service Commission released the Reforming Energy Vision (REV) strategy. The REV initiative will promote more efficient use of energy, deeper penetration of renewable energy resources, wider deployment of distributed energy resources and energy storage. The REV is intended to encourage markets to achieve greater use of advanced energy management products, which will empower customers by providing them more choice in how they manage their electricity usage.

The Public Service Commission reviews and approves NYSERDA's plans and budgets for energy conservation programs.

New York –Independent System Operator

The NY-ISO operates the competitive wholesale markets that mange the flow of electricity across the state of New York. In addition to operating the markets, the NY-ISO prepares analyses, evaluations and forecasts to assist with system planning. This includes the assessment of reliability thresholds, identification of resource needs, evaluation of proposed projects and provision of objective market planning data.

Electric Utilities

The following electric utilities operate in the state of New York. Customers of these utilities are eligible for their own utility programs as well as NYSERDA programs. Double-dipping of incentives by customers is not allowed.

- Central Hudson (Central Hudson Gas & Electric Corporation)
- Con Edison (Consolidated Edison Company of New York, Inc.)
- National Grid (Niagara Mohawk Power Corporation)

- NYSEG (New York State Electric and Gas Corporation)
- Orange and Rockland Utilities, Inc.
- RG&E (Rochester Gas and Electric Corporation)

Electricity Generation

In 2013, electricity in New York was generated by the following resources:

Resource	Contribution
Petroleum	1%
Natural Gas	36%
Coal	1%
Nuclear	33%
Hydroelectric	22%
Other Renewables	6%

NYSERDA OVERVIEW

NYSERDA`s mandate is to promote energy efficiency and the use of renewable energy sources. The objectives are to reduce greenhouse gas emissions, accelerate economic growth and reduce customer energy bills. NYSERDA operates multi-fuel programs, though this document primarily focuses on electricity.

A key element of NYSERDA`s strategy is to work with stakeholders throughout New York including residents, business owners, developers, community leaders, local government officials, university researchers, utility representatives, investors, and entrepreneurs. These interactions ideally provide the conditions that help expand New York`s clean energy economy, allow communities, residents and businesses to benefit from energy efficiency and renewable energy, and to overcome barriers for large-scale clean energy usage.

NYSERDA is governed by a 13-member board. It was created in 1975. Recently, there has been a shift to not compete with the utility programs, but to move toward a market transformation approach.

Sources of Funding

The Systems Benefit Charge (SBC) is the primary source of NYSERDA`s funding for energy conservation programs. It was established on May 20, 1996. The funds collected from the SBC are allocated towards energy efficiency programs, research and development activities, low-income energy programs, and environmental disclosure activities. The SBC was recently extended on December 31, 2016. The SBC is used to fund the Energy Efficiency Portfolio Standard (EEPS). Recently, the EEPS has been replaced by the Clean Energy Fund (CEF).

Other sources of funding include:

- Regional Greenhouse Gas Initiative (RGGI)
- Renewable Portfolio Standard (RPS)

The RGGI is focused on energy efficiency, renewable energy and carbon abatement projects. The funding comes from the sale of carbon emission allowances. The amount of funding available is dependent on the auction price for the allowances. The RGGI covers nine Northeast and Mid-Atlantic states.

The RPS is focused on acquiring renewable energy and/or renewable energy attributes. The funds are approved by the Public Service Commission and derived from an assessment of the intrastate sales of electricity by the utilities in the state of New York.

Retail Prices of Electricity

For a representative number, the following are the retail prices for Con Edison customers in 2014:

- Residential: $0.2885/kWh
- Commercial: $0.2216/kWh
- Industrial: $0.2018/kWh

NYSERDA ENERGY EFFICIENCY PROGRAM INCENTIVE AND COST EFFECTIVENESS POLICY

Cost Effectiveness Testing

Under the EEPS, NYSEDRA was required to conduct cost effectiveness testing at the project level. The TRC is used as the cost effectiveness test. Prior to the implementation of the EEPS, the TRC was applied at the program level. Under the CEF, the TRC will again be applied at the program level.

Avoided Costs

The benefits calculated in the TRC are the avoided supply costs. For NYSERDA, the avoided supply costs include the reduction in costs of electric energy, natural gas, generation and transmission, and distribution capacity, valued at marginal cost for the periods when there is a load reduction. The avoided costs are provided by the NY-ISO.

ENERGY EFFICIENCY PROGRAMMING

Energy efficiency programs are typically set on three year funding cycles, approved by the Public Services Commission. Programs cover both the residential and commercial sectors, and cover various fuel types. The numbers below are only for the electricity conservation programs.

Previous Results (Savings, Expenditure, Cost Effectiveness)

Year	Electricity Savings	Expenditure	Cost Effectiveness
2013	Not Available	Not Available	Not Available
2014	Not Available	Not Available	Not Available
2015	Not Available	Not Available	Not Available

Future Targets

Year	Electricity Savings	Expenditure	Cost Effectiveness
2016	Not Available	Not Available	Not Available
2017	Not Available	Not Available	Not Available
2018	Not Available	Not Available	Not Available

Incentive Level Setting Methodology

One of the key considerations for incentive level setting is to match the incentive to program design. If the program design has certain objectives or uses a specific delivery structure, the incentives should match these considerations.

In the commercial program, smaller projects usually feature a prescriptive incentive that is based on a percentage cost of the measure/project. Usually, the incentives are capped at 50 percent. If a measure is being “jump-started”, there may be

consideration to increase the incentive. For example, for agricultural customers, the incentive can go up to 70 percent of the cost.

For larger projects in the commercial program, there has been a move to a performance based incentive, set using a $/kWh structure. Some incentive structures are developed to reward peak load congestion in certain areas, there may be a usage of a $/kW structure, or a blended approach is used.

In the commercial programs, project costs are always recorded to track the contribution of incentives.

Incentive levels are based on historical experience. The end use is identified and the incentives are based on the experience in that area.

Incentive levels are reviewed every year for residential programs. For commercial programs, the goal is to have a review once a year, but if the measures are less used, this may not happen. Certain measures are reviewed multiple times a year. For example, LED lighting has been a challenge. The initial incentives were set at 50 percent of the cost, but prices changed so quickly that incentives ended up being much higher as a percentage of costs.

A key part of the program management and incentive setting process is to talk to customers, the supply chain and stakeholders to identify barriers. Communication is ongoing through typical program management activity. There are also program evaluations every year, which provide a formal platform for customer, supply chain and stakeholder communication.

For incentive changes, cost effectiveness is checked. Typically, incentive changes feature reductions, so cost effectiveness impact is usually positive.

During the incentive setting process, a formal document is not required to be submitted. Instead, the regular program change process is followed. If cost effectiveness is impacted negatively through a change in incentive, there would be a discussion with the Public Service Commission.

To support the incentive setting process, a measures list has been created that documents measure savings and costs. It is owned by the program evaluation group. This activity is supported by research to gauge penetration levels, and further understand savings assumptions.

- For incentive changes, do check cost effectiveness, most incentives are coming down so it is more based on product price
- Program evaluation talk to supply chain
- Not required to submit any formal document, just do regular program changes if benefit cost is better
- If benefit cost gets worse, we would discuss
- Have built measures list, owned by evaluation group, do penetration and savings level research

APPENDIX A-8: VERMONT (EFFICIENCY VERMONT)

SUMMARY

Jurisdictional Scan	
State/Province	Vermont
Utility/Agency	Efficiency Vermont (Vermont Energy Investment Corporation)
Fuel	Electricity, Gas, Heating Fuels
Key Contact/Interviewee	Robert Stephenson, Chris Gordon
Consultant	Mayuran Srikantha

JURISDICTION OVERVIEW

Electricity Market

The following entities make up the electricity system in Vermont.

- Efficiency Vermont (Vermont Energy Investment Corporation – VEIC)
- Vermont Public Services Board (PSB)
- ISO New England (ISO-NE)
- Vermont Electric Power Company (VELCO) → transmission company state owned
- 17 Electric Utilities

Efficiency Vermont was the first state-wide energy efficiency utility of its kind in North America. It was established in 1999 through regulation from the PSB. Efficiency Vermont runs through a contract between the PSB and VEIC, the current owner and operator of Efficiency Vermont. VEIC is an independent, not-for-profit organization that was started in 1986.

In 1999, the PSB decided to create a state-wide energy efficiency utility to administer electricity conservation programs for the whole state. It was believed that electric utilities have a split incentive to administer these programs since their revenue came from electricity sales, not reduction. A volumetric charge was established on electric customers' bills in Vermont to support these programs, and was to be collected by utilities who offered Efficiency Vermont's programs to their customers. Burlington Electric Department, one of the municipally owned electric utilities, chose to administer their own electricity conservation programs, which are funded through a separate agreement with the PSB. Most of Burlington Electric Department's programs are identical to Efficiency Vermont.

The PSB is a quasi-judicial board that supervises the rates, quality of service and overall financial management of Vermont's utilities (cable television, electricity, gas, telecommunications, water and large waste water companies). The board oversees Vermont's Energy Efficiency Utility (EEU) Program. It sets the Energy Efficiency Charge (EEC) that appears on utility customers' bills that fund the EEU Program. The PSB is responsible for procuring the resources to support the EEU Program, and to manage and review the performance of those resources. For the current cycle, the electricity efficiency is provided by Efficiency Vermont and Burlington Electric Department.

ISO New England (ISO-NE) is the Regional Transmission Organization (RTO) that manages New England's bulk power generation and transmission system. ISO-NE has three main objectives:

1. Ensure daily reliable operation of New England's bulk power generation and transmission system
2. Oversee and ensure fair administration of region's wholesale electricity market
3. Manage a comprehensive regional planning process

Vermont Electric Power Company (VELCO) operates Vermont's bulk transmission system and represents the utilities in power pool discussions with ISO-NE. VELCO was set up in 1956 to develop an integrated transmission system to interconnect the different electric utilities in Vermont. VELCO is regulated, and is owned and controlled by the state's electric utilities and the

Vermont Low-Income Trust for Electricity (VLITE). VELCO takes part in the regional planning process by performing and directing planning, design and construction efforts for Vermont's bulk transmission system.

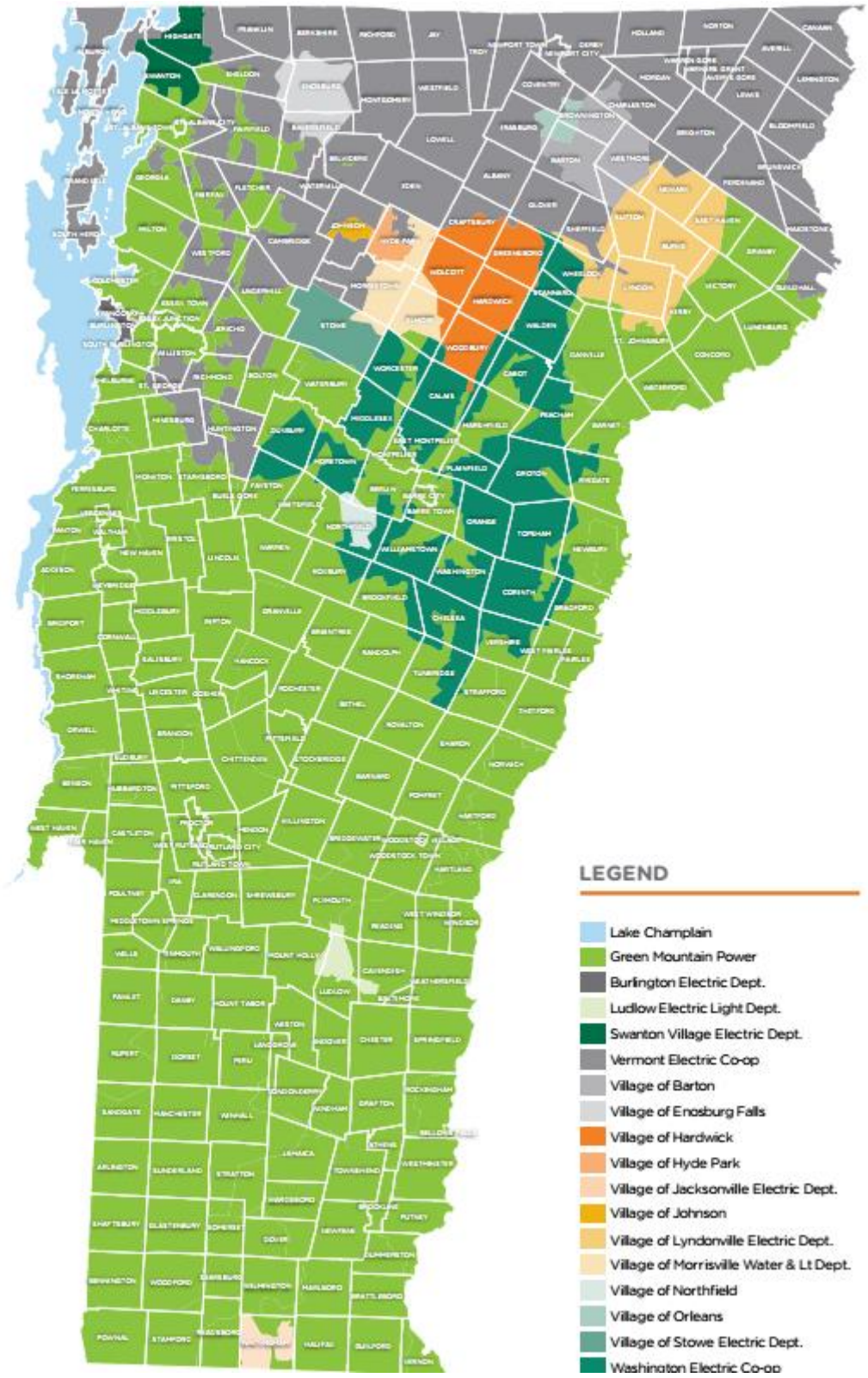
Electric Utilities

Vermont has 17 electric utilities.

- 14 municipal electric utilities
- 1 investor owned utility (IOU)
- 2 cooperatives

Vermont's utilities range in size. The smallest is Village of Orleans Electric Department with 700 customers, and the largest is Green Mountain Power with 256,000 customers. Green Mountain Power is the only investor owned utility in the state. The 2 cooperatives are Vermont Electric Cooperative and Washington Electric Cooperative. The following map illustrates their service territories[1]:

[1] http://www.greenmountainpower.com/upload/photos/201ServiceMapLarge.jpg


LEGEND
Lake Champlain
Green Mountain Power
Burlington Electric Dept.
Ludlow Electric Light Dept.
Swanton Village Electric Dept.
Vermont Electric Co-op
Village of Barton
Village of Enosburg Falls
Village of Hardwick
Village of Hyde Park
Village of Jacksonville Electric Dept.
Village of Johnson
Village of Lyndonville Electric Dept.
Village of Morrisville Water & Lt Dept.
Village of Northfield
Village of Orleans
Village of Stowe Electric Dept.
Washington Electric Co-op

Electricity Generation

In 2014, Vermont was dominated by two types of generation sources; nuclear power and hydroelectric. Nuclear power made up about 70 perent of generated electricity, with hydroelectric making up another 20 percent. The next two largest resources were wood burning and wind generation, which make up the majority of the remaining 10 percent. From its electricity generation activities, Vermont does not have a large greenhouse gas commitment from coal, oil or natural gas. The state's only nuclear power plant closed at the end of 2014.

Total Energy Production (MWh)	**6,884,910**
Hydroelectric	1,285,912
Natural gas	3,029
Nuclear	4,846,327
Other biomass	25,698
Petroleum	5,103
Solar	17,293
Wind	236,034
Wood	465,513

Vermont is summer peaking with a load of 1,255 MW. Of the 6,900 GWh of generation, over 85 percent comes from large scale generators and CHP units, while the rest comes from electric utilities. The majority of generators participate in ISO- NE's forward capacity market.

VERMONT ENERGY EFFICIENCY PROGRAM INCENTIVE AND COST EFFECTIVENESS POLICY

Vermont is viewed as one of the leading jurisdictions for promoting conservation in North America. Vermont Energy Investment Corporation (VEIC) has won multiple awards during the past twenty years from industry associations such as ENERGY STAR®, American Council for an Energy Efficient Economy (ACEEE) and Association of Energy Service Professionals (AESP).

Vermont does not have state legislation that sets energy efficiency targets for each year. Instead, it follows a policy of setting energy efficiency budgets that achieve "all reasonably available, cost effective energy efficiency". The specific budgets and targets are negotiated between the PSB and VEIC, which operates Efficiency Vermont. There is no explicit penalty for not meeting the targets, but a portion of the payments are contingent upon performance, which is subject to an Evaluation, Measurement and Verification (EM&V) process.

The budgets and targets are established in three year cycles. The current cycle, 2015-2017 has a savings target of 321,800 MWh for VEIC. This is measured in annual, incremental net savings. Efficiency Vermont is also held to a total resource benefits target of $336.3 million as indicated by the present value of the benefits of the TRC test. For scale purposes, in 2014, Efficiency Vermont achieved 91,000 MWh of savings, meaning the new cycle is more aggressive than recent results.

In addition to Burlington Electric Department's targets, the total energy savings target for Vermont for the 2015-2017 is equivalent to about 2.1 percent of sales each year.

Every three year cycle is determined through a Demand Resource Plan (DRP) process that has a 20 year horizon. This process sets the three year energy conservation savings and budget targets.

According to the latest update to the 2015-2017 Triennial Plan submitted by Efficiency Vermont, the resource acquisition budgets for electricity are as follows for 2015, 2016 and 2017 respectively: $42.35M, $39.46M and $45.56M.

The total budget for all of Efficiency Vermont's portfolio from 2015-2017, including the performance award is indicated below:

5.1.2 2015-2017 Budget by Market and Initiative

	2015 [1]	2016	2017	2015-2017
RESOURCE ACQUISITION				
Electric Efficiency				
Business Sector				
Business Existing Facilities	$ 18,420,756	$ 17,193,540	$ 21,641,426	$ 57,255,722
Customer Credit	$ 312,309	$ 1,686,279	$ 1,029,372	$ 3,027,960
Business New Construction	$ 3,207,177	$ 2,954,285	$ 3,046,426	$ 9,207,888
Sub-Total Business Sector	$ 21,940,243	$ 21,834,103	$ 25,717,224	$ 69,491,570
Residential Sector				
Efficient Products	$ 13,941,148	$ 12,525,075	$ 13,495,259	$ 39,961,481
Existing Homes	$ 3,949,947	$ 3,794,029	$ 4,284,024	$ 12,028,000
Residential New Construction	$ 2,832,331	$ 2,993,140	$ 3,088,289	$ 8,913,759
Sub-Total Residential Sector	$ 20,723,425	$ 19,312,244	$ 20,867,571	$ 60,903,240
Research & Development	$ 1,228,855	$ 2,568,977	$ 1,206,235	$ 5,004,067
Total Electric Efficiency	$ 43,892,523	$ 43,715,324	$ 47,791,030	$ 135,398,877
Thermal Energy and Process Fuels Efficiency				
Business Sector	$ 565,997	$ 1,417,372	$ 1,417,372	$ 3,400,741
Residential Sector	$ 5,103,491	$ 4,252,116	$ 4,252,116	$ 13,607,723
Total Thermal Energy and Process Fuels Efficiency	$ 5,669,488	$ 5,669,488	$ 5,669,488	$ 17,008,464
TOTAL RESOURCE ACQUISITION ACTIVITIES	$ 49,562,011	$ 49,384,812	$ 53,460,518	$ 152,407,341
NON RESOURCE ACQUISITION				
Education and Training	$ 837,950	$ 854,700	$ 871,810	$ 2,564,460
Applied Research and Development	$ 403,725	$ 411,800	$ 420,040	$ 1,235,565
Planning and Reporting	$ 415,000	$ 614,270	$ 626,570	$ 1,655,840
Evaluation, Measurement and Verification	$ 880,000	$ 897,600	$ 915,560	$ 2,693,160
Policy and Public Affairs	$ 493,025	$ 502,880	$ 512,950	$ 1,508,855
Information Technology	$ 1,501,000	$ 1,199,020	$ 1,222,500	$ 3,922,520
General Administration	$ 261,400	$ 266,630	$ 271,970	$ 800,000
TOTAL NON-RESOURCE ACQUISITION	$ 4,792,100	$ 4,746,900	$ 4,841,400	$ 14,380,400
Operations Fee	$ 972,752	$ 944,018	$ 1,030,906	$ 2,947,676
Sub-Total Prior to Performance-Based Fee	$ 55,326,863	$ 55,075,730	$ 59,332,824	$ 169,735,417
Performance-Based Fee (set-aside)	$ 1,459,129	$ 1,416,027	$ 1,546,359	$ 4,421,514
TOTAL BUDGET INCLUDING PERFORMANCE-BASED FEE	$ 56,785,992	$ 56,491,757	$ 60,879,183	$ 174,156,931

[1] The 2015 NRA budgets were modified in the digital version on 12/2/2015 and will therefore not align with the printed versions.

Cost Effectiveness Testing

Efficiency Vermont is responsible for achieving “all reasonable available, cost effective energy efficiency” within the provided budget.

The PSB conducts an annual savings verification process to compare achievement against the initial plan.

The Technical Advisory Group (TAG) contains members from Efficiency Vermont, PSB, Burlington Electric Department and other stakeholders to resolve any issues with the annual savings verification process and to track implementation of any recommendations that arise from the annual verification process.

The TRM contains a list for the prescriptive measures, which represent about 2/3 of overall electricity savings in the portfolio. It indicates the methodology for how energy savings can be calculated for each measure, along with the supporting assumptions such as incremental costs, and free ridership rates. The TRM uses deemed savings for the majority of measure contained; however the deemed savings have the algorithms and assumptions to help improve accuracy. For some measures, there are calculation-based savings that use specific input parameters such as hours of operation or efficiency level.

For the 2011-2013 period, an independent audit of Efficiency Vermont's and Burlington Electric Department's program cost effective was conducted. This review was completed in September, 2015. The findings show that the portfolio had a Societal Cost Test (SCT) of 2.66 and a Program Administrator Cost (PAC) test of 3.05. These numbers seem to be in alignment with the savings, budget and benefits targets from the 2015-2017, though they do support the premise that the 2015-2017 is more aggressive for obtaining savings, with a resulting decrease in cost effectiveness.

Efficiency Vermont uses the SCT, not the TRC, for determining cost effectiveness at the measure level and the portfolio level. PAC is only used at the portfolio level. In general, measures must pass the SCT screening, but exceptions do occur for a variety of reasons. For example, low income programs have an additional 15 percent adder for benefits to reflect the societal value of efficiency in the low income market.

Avoided Costs[2]

Any updates to the avoided costs for Vermont are led by the PSB. Periodically, the avoided costs are updated. The last update occurred in 2015, based on a report by Synapse Energy Economics, which investigated the avoided energy supply costs for New England. Before any changes are implemented, they must be reviewed and approved by the board. The avoided costs are calculated for the entire New England Region, and then separated into different geographic areas, of which Vermont is one area.

For electricity, the major categories of benefit are:

- Avoided Capacity Costs
- Avoided Energy Costs
    - These costs include the reduction in cost of renewable energy that needs to be acquired to comply with Renewable Portfolio Standards (RPS).
- Transmission and Distribution Costs
    - These are assumed at the local level.
- Capacity Demand Reduction Induced Price Effect (DRIPE)
- Energy DRIPE
- Electricity Cross-Fuel DRIPE
- Avoided Non-Embedded CO_2 Costs

EFFICIENCY VERMONT –OVERVIEW

Utility Facts

- Serves all of Vermont, other than Burlington Electric Department customers
- Over 9,500 square miles
- Services population of 500,000
- Funded through energy efficiency charge collected by participating electric utilities.

[2] Avoided Costs - http://psb.vermont.gov/sites/psb/files/projects/EEU/2013avoidedcosts/AESCReport-WithAppendicesAttached.pdf

Customer Class Breakdown

There are three types of customers:

- Residential
- Commercial – Without Demand Charge
- Commercial – With Demand Charge

Retail Prices of Electricity

In Vermont, the bundled retail prices for electricity are as follows for the different utilities[3]:

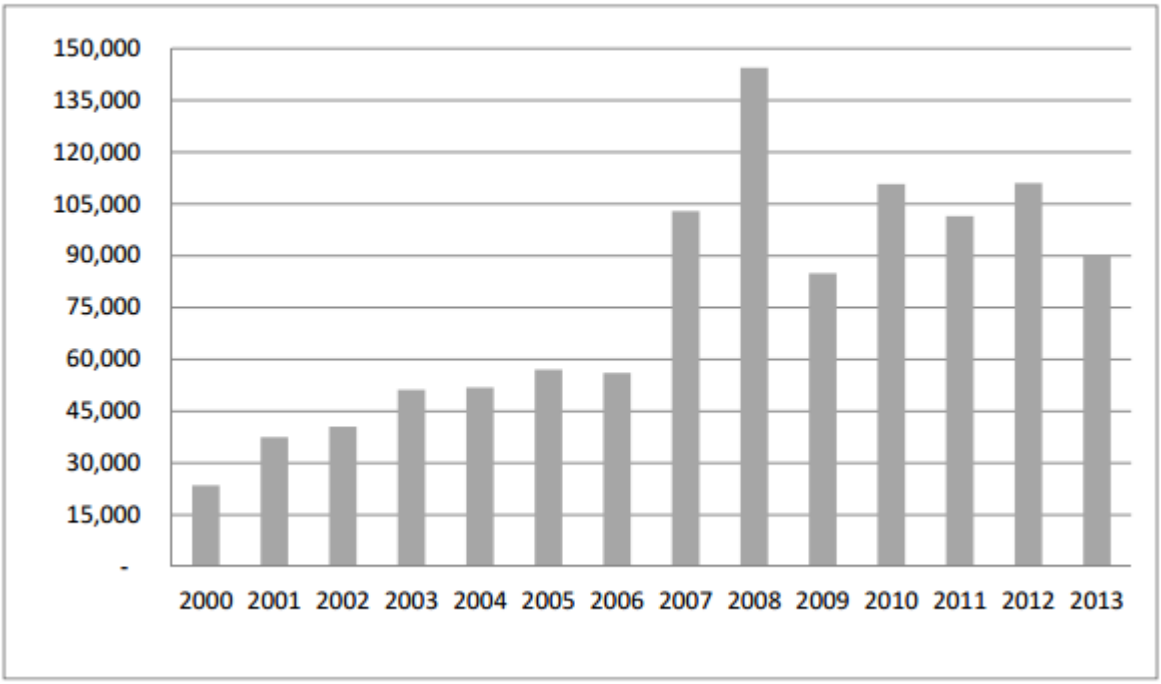
Entity	State	Ownership	Customers (Count)	Sales (MWh)	Revenues (Thousands Dollars)	Average Price (cents/kWh)
City of Burlington Electric - (VT)	VT	Municipal	20,557	338,421	47,086.0	13.91
Green Mountain Power Corp	VT	Investor Owned	258,928	4,281,682	609,832.0	14.24
Town of Hardwick	VT	Municipal	4,492	32,763	5,856.0	17.87
Town of Stowe- (VT)	VT	Municipal	4,033	74,414	11,366.5	15.27
Vermont Electric Cooperative, Inc	VT	Cooperative	38,542	446,870	74,409.5	16.65
Village of Ludlow - (VT)	VT	Municipal	3,758	47,118	7,439.0	15.79
Village of Lyndonville - (VT)	VT	Municipal	5,675	64,937	9,848.0	15.17
Village of Morrisville - (VT)	VT	Municipal	3,986	44,827	7,119.0	15.88
Village of Northfield - (VT)	VT	Municipal	1,866	29,570	3,998.8	13.52
Village of Swanton - (VT)	VT	Municipal	3,632	53,710	6,791.0	12.64
Washington Electric Coop - (VT)	VT	Cooperative	10,836	69,993	13,566.0	19.38

EFFICIENCY VERMONT - ENERGY EFFICIENCY PROGRAMMING

Vermont Energy Investment Corporation (VEIC) has been delivering energy efficiency programs since 1987. In 1999, Efficiency Vermont was created through the award of a contract from the Public Services Board to create North America's first energy efficiency utility. Programs began for customers in March, 2000. Since then, Efficiency Vermont has delivered 12.7 million MWhs in savings.

[3] http://www.eia.gov/electricity/data.cfm#sales

Figure 1. Efficiency Vermont annualized megawatt-hour savings



Savings

Efficiency Vermont programs have proven very successful at reducing energy consumption and incentivizing energy efficient behaviours and investment decisions. In the 2012-2014 period, Efficiency Vermont had the following results:

Table 1. Key results for 2012–2014

	2012	2013	2014	2012–2014 Total
Energy savings in megawatt-hours (MWh)	110,179	85,582	91,146	286,907
Total Resource Benefits[2]	$118,358,445	$83,830,177	$82,101,439	$284,290,061
U.S. tons of carbon dioxide emissions avoided through efficiency	800,000	690,000	700,000	2,190,000

Table 2. Selected QPI results for the 2012–2014 performance period[4]

Key Quantifiable Performance Indicators (QPIs)	Funding Pool	2012–2014 Goals	2012–2014 Results	% of Goal Achieved
Electric savings (MWh)	Electric Efficiency Charge	274,000	286,907	105%
Total Resource Benefits	Electric Efficiency Charge	$305,984,352	$284,290,061	93%
Statewide summer peak kilowatt (kW) demand reduction	Electric Efficiency Charge	41,920	35,979	86%
Summer peak kW demand reduction in Geographic Targeting areas—Susie Wilson Road	Electric Efficiency Charge	1,570	1,626	104%
Summer peak kW demand reduction in Geographic Targeting areas—Saint Albans	Electric Efficiency Charge	1,800	2,086	116%
Ratio of gross electric benefits to spending	Electric Efficiency Charge	1.2	2.0	163%
Million British thermal unit (MMBtu) savings	Thermal Energy and Process Fuels Revenues	155,000	168,795	109%

Budget & Spending

Efficiency Vermont's spending for 2013 and 2014 is provided below:

	Prior Year	Current Year 2014	Cumulative starting 1/1/12	Cumulative starting 1/1/12
# participants with installations	37,483	54,135	131,094	131,094
Operating Costs				
Administration	$1,440,935	$3,345,878	$6,107,129	$6,107,129
Operations and Implementation	$4,944,156	$5,077,234	$14,289,871	$14,289,871
Strategy and Planning	$1,735,071	$1,537,498	$4,652,934	$4,652,934
Subtotal Operating Costs	**$8,120,163**	**$9,960,610**	**$25,049,934**	**$25,049,934**
Technical Assistance Costs				
Services to Participants	$4,924,708	$3,987,615	$13,596,176	$13,596,176
Services to Trade Allies	$392,440	$1,559,789	$2,296,467	$2,296,467
Subtotal Technical Assistance Costs	**$5,317,148**	**$5,547,404**	**$15,892,643**	**$15,892,643**
Support Services				
Transportation	$369	$4,255	$4,623	$4,623
Targeted Implementation	$4,584	$1,407	$5,991	$5,991
Consulting	$315,962	$490,162	$911,282	$911,282
Marketing	$2,507,460	$2,177,538	$5,973,105	$5,973,105
EM&V	$146,611	$183,942	$516,438	$516,438
Policy	$35,328	$61,712	$199,017	$199,017
Information Technology	$1,218	$80,913	$82,411	$82,411
Customer Support	$207,074	$400,744	$787,512	$787,512
Business Development	$24,833	$19,090	$51,065	$51,065
Subtotal Support Services Costs	**$3,243,439**	**$3,419,764**	**$8,531,443**	**$8,531,443**
Incentive Costs				
Incentives to Participants	$15,634,949	$22,831,035	$56,723,746	$56,723,746
Incentives to Trade Allies	$36,917	$53,428	$164,974	$164,974
Subtotal Incentive Costs	**$15,671,866**	**$22,884,463**	**$56,888,720**	**$56,888,720**
Total Efficiency Vermont Costs	**$32,352,615**	**$41,812,241**	**$106,362,740**	**$106,362,740**
Total Participant Costs	$23,822,816	$22,482,896	$47,632,567	$47,632,567
Total Third Party Costs	$855,513	$963,025	$3,122,038	$3,122,038
Total Resource Acquisition Costs	**$57,030,944**	**$65,258,162**	**$157,117,345**	**$157,117,345**

Annualized MWh Savings	89,679	91,159	292,063	292,063
Lifetime MWh Savings	1,041,327	1,101,613	3,388,175	3,388,175
TRB Savings (2012 $)	$88,029,132	$82,129,788	$289,655,512	289,655,512
Winter Coincident Peak kW Savings	16,656	16,519	55,261	55,261
Summer Coincident Peak kW Savings	11,222	10,326	36,762	36,762
Annualized MWh Savings/Participant	2.393	1.684	2.228	2.228
Weighted Lifetime	11.6	12.1	11.6	11.6

Vermont 2013-2014 Incentive vs. Total Program Spending and Spending per kWh Ratios		
2013	48%	$0.36/kWh
2014	55%	$0.46/kWh

Cost Effectiveness

Efficiency Vermont is not held to a direct cost effectiveness metric, but the plan must meet associated savings, spending and total resource benefit targets. The annual savings verification process captures program to these targets. The latest independent audit of Vermont's energy efficiency portfolio for the 2011-2013 period provided the following results:

Vermont 2013-2015 Cost Effectiveness Results	
SCT	2.66
PAC	3.05

Based on analysis of the 2015-2017 program targets and budgets, it is assumed that the cost effectiveness projections will be slightly decreased, compared to historical performance.

FUTURE TARGETS

The 2015-2017 period has a savings target of 321,800 MWh, with an associated electricity savings resource acquisition budget of just over $130 million. The total budget for Efficiency Vermont's budget which included revenues collected from the efficiency charge, the Regional Greenhouse Gas Initiative and the ISO-NE Forward Capacity market as well as the performance fee is $174 million.

INCENTIVE LEVEL SETTING METHODOLOGY

Efficiency Vermont developed a new product development process about a year and a half ago. It involves a customer mapping and an engagement process that covers seven stages:

1. Idea Solicitation
2. Idea Screening
3. Concept Development
4. Market Analysis
5. Prototyping
6. Market Testing
7. Product Development
8. Product Launch
9. Post Launch Review

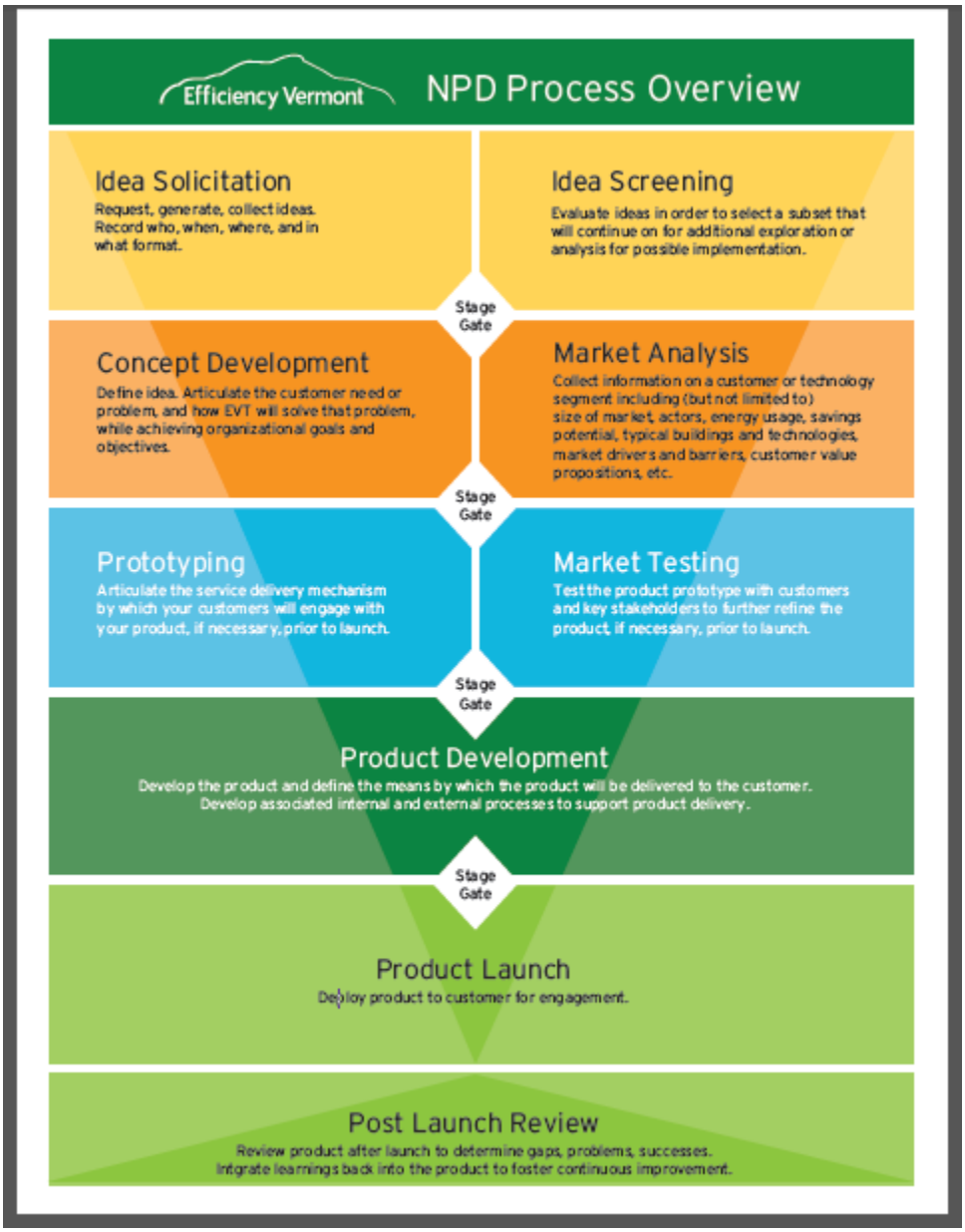


Figure 48: Efficiency Vermont New Product Development Process

If a new incentive offer or program is being designed, this process is used. If the incentive has been in place for a while, and program delivery is not changing, the process is not necessarily followed.

If there is a need for an expedited change, the process can be shortened by reducing some of the check list items.

Ideally, the NPD process is consistent between the residential and commercial markets. Usually, if there are changes to the program design, they occur on a six months to a year cycle.

Efficiency Vermont uses a strong data tracking approach for performance and opportunities. Program managers are required to provide forecast and actual data every month for the year ahead.

Cost effectiveness is performed using the societal test. There are different adders for different factors.

Incentives are typically changed based on customer behaviour; not cost effectiveness. Free-ridership is assessed for incentive levels.

Efficiency Vermont conducts market research on a project basis, but the findings are leveraged for the annual planning process as required.

Every measure has its energy savings assumptions evaluated every three years at a minimum. Usually, measures are reviewed for their savings assumptions every year or every two years.

EFFICIENCY VERMONT CORE PROGRAM OFFERINGS (RESIDENTIAL AND BUSINESS)

Program Name	Program Area	Program Measures (Prescriptive Incentives)	Links
Agricultural Equipment Rebates	Agricultural (Commercial)	• Lighting • Equipment Rebates are paid after purchase and submission of rebate form. Certain products are qualified through a qualifying product list or through provided specifications. Incentives are either prescriptive or quasi-prescriptive based on equipment characteristics.	https://www.efficiencyvermont.com/Media/Default/docs/rebates/forms/efficiency-vermont-agricultural-lighting-equipment-rebate-form.pdf
Appliances	Residential	• Dehumidifiers • Clothes Dryers • Clothes Washers • Refrigerators Rebates are paid after purchase and submission of rebate form. All rebated products are qualified through a qualifying product list.	https://contractors.efficiencyvermont.com/rebates
Electronics	Residential	• Advanced Power Strips Incentive provided through a coupon at participating retailer. All products are qualified through a qualifying product list.	https://contractors.efficiencyvermont.com/rebates
Heating, Cooling and Ventilation	Residential and Commercial	• Commercial HVAC • Heat Pump Water Heaters • Cold Climate Heat Pump • High Performance Circulator Pump • Residential Heating Systems • Residential Water Heating Rebates are paid after purchase and submission of rebate form. Certain products are qualified through a qualifying product list or through provided specifications. Some of the qualifying lists are upstream, so the incentive is provided instantly, versus through a mail-in form. Incentives are either prescriptive or quasi-prescriptive based on equipment characteristics.	https://contractors.efficiencyvermont.com/rebates
Industrial & Special Equipment		• Compressed Air • Pool Pumps Rebates are paid after purchase and submission of rebate form. Certain products are qualified through a qualifying product list or through provided specifications.	https://contractors.efficiencyvermont.com/rebates

Program Name	Program Area	Program Measures (Prescriptive Incentives)	Links
		Incentives are either prescriptive or quasi-prescriptive based on equipment characteristics.	
Lighting	Residential	• CFLs • LEDs Incentives provided at participating retailers. Minimum prices are $0.99 for CFLs and $3.99 for LED products.	
Lighting	Commercial	• LED Fixtures • Lighting Controls Rebates are paid after purchase and submission of rebate form. Products are qualified through provided specifications. Incentives are either prescriptive or quasi-prescriptive based on equipment characteristics.	https://contractors.efficiencyvermont.com/rebates
Refrigeration and Commercial Kitchens	Commercial	• Commercial Kitchen Equipment • Commercial Refrigeration Rebates are paid after purchase and submission of rebate form. Products are qualified through provided specifications. Incentives are either prescriptive or quasi-prescriptive based on equipment characteristics.	https://contractors.efficiencyvermont.com/rebates
Residential Rental Properties	Commercial	• Refrigerators • Ventilation Systems • Boilers • Furnaces • Free Energy Efficiency Products (Aerators, Showerheads, CFLs) Rebates are paid after purchase and submission of rebate form. Products are qualified through provided specifications. Incentives are either prescriptive or quasi-prescriptive based on equipment characteristics.	https://contractors.efficiencyvermont.com/rebates
Home Performance with ENERGY STAR®	Residential	• Insulation and Building Envelope (Up to $2,000) • Heating System Incentive ($500) Participation requires hiring a trained Home Performance with ENERGY STAR contractor. After the qualifying measures are installed, the contractor reports the completed work for Efficiency Vermont for review. After review, the incentives are paid.	https://www.efficiencyvermont.com/Media/Default/docs/rebates/forms/efficiency-vermont-home-performance-with-energy-star-incentive-overview.pdf
Residential New Construction	Residential/ Commercial	• Insulation and Building Envelope • HVAC Equipment • Lighting • Appliances Up to $2,000 in incentives. The home has to be issued with a Home Energy Rating (HERS) index score.	https://www.efficiencyvermont.com/Media/Default/docs/services/brochures/efficiency-vermont-residential-new-construction-specifications-and-incentives.pdf

APPENDIX A-9: MAINE (EFFICIENCY MAINE)

GEOGRAPHIC DEFINITIONS

Efficiency Maine is the body that incents energy efficiency practices in the state of Maine, USA. They are responsible for developing, planning, coordinating and implementing energy efficiency and alternative energy resource programs in the entire state; this includes electric and gas fuel programs.

LOAD AND CONSUMPTION INFORMATION (ELECTRIC)

Electricity in Maine is distributed by ISO New England. Northern Maine Independent System Operator services northern Maine.

Maine itself has 13 electric utility suppliers. Three of these utilities are the main players in the market serving over 90 percent of the customers in state. Maine has a population of 1.33 million.

Peak Demand (2014): 2,200 MW[1]

Figure 49: Number of Customer Accounts[2]

Maine					
All sectors		805,178	806,103	806,950	819,638
Residential		709,288	710,160	710,988	721,508
Commercial		92,844	92,884	92,896	95,047
Industrial		3,046	3,059	3,066	3,083
Transportation		0	0	0	0

Figure 50: Customer Rates (2015) [3]

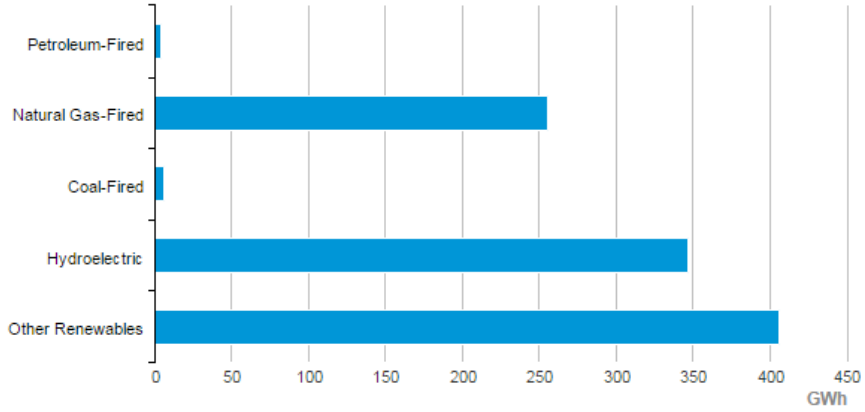
	Residential (Cents/kWh)	Commercial (Cents/kWh)	Industrial (Cents/kWh)	Transportation (Cents/kWh)
Efficiency Maine	15.67	13.15	9.06	-

[1] Maine Public Utilities Commission, "2014 Annual Report," http://www.maine.gov/mpuc/about/annual_report/documents/2014AnnualReportFinaltoPrinter.pdf (February, 2015)
[2] US Energy Information Administration, "Number of customer accounts, monthly," http://www.eia.gov/electricity/data/browser/#/topic/56?agg=0,1&geo=004&endsec=vg&linechart=ELEC.CUSTOMERS.ME-ALL.M&columnchart=ELEC.CUSTOMERS.ME-ALL.M&map=ELEC.CUSTOMERS.ME-ALL.M&freq=M&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0
[3] U.S. Energy Information Administration, "Average retail price of electricity to ultimate customers," http://www.eia.gov/electricity/data.cfm#sales (February 2015)

Figure 51: Retail Sales of Electricity (Million kilowatt-hours)[4]

	2012	2013	2014	2015
Retail sales of electricity (million kilowatthours)				
New England				
All sectors	120,456	121,357	119,983	119,311
Residential	47,208	48,369	47,212	47,397
Commercial	44,864	44,938	53,107	53,158
Industrial	27,818	27,472	19,107	18,178
Transportation	566	577	557	577
Other	--	--	--	--
Maine				
All sectors	11,561	11,855	12,003	11,955
Residential	4,481	4,662	4,661	4,624
Commercial	4,053	4,016	3,985	3,973
Industrial	3,027	3,177	3,357	3,358
Transportation	0	0	0	0
Other	--	--	--	--

Figure 52: Maine Net Electricity Generation by Source, Dec. 2015 [5]



[4] U.S. Energy Information Administration, "Retail sales of electricity, annual," http://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=o04&freq=A&start=2001&end=2015&ctype=linechart&ltype=pin&rtype=s&rse=0&maptype=0&pin=

[5] U.S. Energy Information Administration, "Maine Net Electricity Generation by Source, Dec. 2015," https://www.eia.gov/state/print.cfm?sid=ME

LOAD AND CONSUMPTION INFORMATION (NAUTRAL GAS)

Maine's gas is serviced by four gas utilities[6]:

- Northern Utilities, d/b/a Unitil
- Bangor Gas Company, L.L.C.
- Maine Natural Gas, Corporation
- Summit Natural Gas of Maine, Inc.

The Maine Public Utilities Commission (MPUC) regulates the natural gas pipelines and gas utilities[7].

Figure 53: Natural Gas Consumption (Maine) [8]

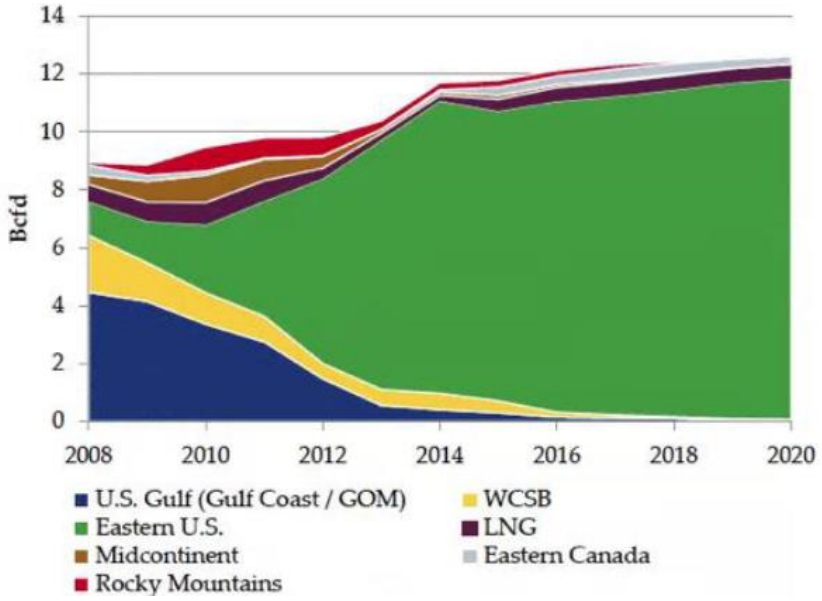
	2010	2011	2012	2013	2014	2015
Total Consumption	77,575	71,690	68,266	64,091	60,661	
Pipeline & Distribution Use	1,753	2,399	762	844	1,300	
Volumes Delivered to Consumers	75,821	69,291	67,504	63,247	59,362	NA
Residential	1,234	1,409	1,487	1,889	2,357	2,605
Commercial	5,830	6,593	7,313	8,146	9,030	9,795
Industrial	28,365	27,734	30,248	32,308	24,121	NA
Vehicle Fuel	1	1	1	*	1	1
Electric Power	40,392	33,555	28,456	20,904	23,853	17,447

Figure 54: Customer Rates (2014)[9]

	Residential ($/Cubic ft.)	Commercial ($/Cubic ft.)	Industrial ($/Cubic ft.)	Transportation ($/Cubic ft.)
Efficiency Maine	16.90	15.13	11.93	-

[6] Maine Public Utilities Commission, "Natural Gas Distributors," http://www.maine.gov/mpuc/natural_gas/distributors.html (2008)
[7] Office of the Revisor of Statutes Maine, "Title 35-A: Public Utilities," http://legislature.maine.gov/legis/statutes/35-A/title35-Ach0sec0.html (January 2016)
[8] U.S. Energy Information Administration, "Natural Gas Consumption by End Use," https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SME_a.htm (March 2016)
[9] U.S. Energy Information Administration, "Natural Gas Prices," http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SME_a.htm (March, 2016)

Figure 55: Sources of Gas Supply in the U.S. Northeast Region, Including New England



MARKET STRUCTURE OVERVIEW

The Efficiency Maine Trust Act came in effect in 2009 and is responsible for Efficiency Maine's inception as an independent Trust. Their purpose is to develop, plan, coordinate, and implement energy efficiency/alternative energy resource programs across the state of Maine. These purposes are accompanied by 10- and 20-year energy savings aspirations which are integrated into the strategy and budgets of the Triennial Plans[7]. These aspirations include:

- Weatherizing 100 percent of residences and 50 percent of businesses by 2030
- Reducing peak-load electric energy consumption by 100 megawatts by 2020
- Reducing the state's consumption of liquid fossil fuels by at least 30 percent by 2030
- By 2020, achieving electricity and natural gas savings of at least 30 percent and heating fuel savings of at least 20 percent as defined in and determined pursuant to the measures of performance ratified by the commission under section 10120
- Capturing all cost-effective energy efficiency resources available for electric and natural gas utility ratepayers
- Saving residential and commercial heating consumers not less than $3 for every $1 of program funds invested by 2020 in cost-effective heating and cooling measures that cost less than conventional energy supply
- Building stable private sector jobs providing clean energy and energy efficiency products and services in the state by 2020
- Reducing greenhouse gas emissions [10 percent below 1990 levels by 2020] from the heating and cooling of buildings in the state

According to the act[7], Efficiency Maine, in consultation with entities and agencies engaged in delivering efficiency and weatherization programs in the state, is to develop a triennial plan. The triennial plans has to include identification of all achievable cost-effective energy efficiency savings, programs to address these savings potential and the associated costs and benefits with the basis of these costs and benefits presented. It is the MPUC's responsibility to review and approve or deny triennial plans submitted. Upon approval of the plan, the MPUC orders

the state's electric utilities to collect the applicable budget from their customers and remit it to the Trust for its programs.

An independent evaluation of each major program implemented is conducted at least every five years. This evaluation must include an accounting audit and program effectiveness of meeting its goals evaluation. These results are included in the annual report submitted. "Major" programs are defined as programs with annual budgets greater than $500,000.

The amount of funding available is determined by the budget needed to achieve the maximum achievable cost-effective (MACE) energy efficiency potential approved by the MPUC. Efficiency Maine also typically offsets some of funding through a variety of sources such as through Maine ratepayers, revenues from the Forward Capacity Market and a long-term contract with Maine utilities.

Energy efficiency has been determined to be the lowest cost energy resource in the state of Maine. The cost to save electricity through efficiency upgrades averaged 4.3 cents/kWh. The cost of saving heating fuels (heating oil, propane, natural gas, wood, and kerosene) through weatherization and high-efficiency heating equipment averaged $12.96/MMBtu.

PORTFOLIO MATURITY AND HISTORICAL PERFORMANCE

DSM programs were administered by electric utilities before 2002. Efficiency Maine was then established in 2002 to promote electricity efficiency, reduce energy costs and improve the environment statewide. During this time, Efficiency Maine was part of the MPUC. It later became an independent Trust by 2009.

Efficiency Maine Program Impacts 2004-2010[10]:

- 2004-2010 Cumulative Annual MWh Savings: **486,342**
- 2004-2010 Cumulative Lifetime MWh Savings: **4,646,248**
- 2004-2010 Cumulative Benefit to Cost Ratio: **2.92**
- 2004-2010 Cumulative Cost/kWh: **3.6 cents**

CURRENT CYCLE

Efficiency Maine began Triennial Plans in 2011 and is currently in the second triennial cycle that spans 2014-2016. Efficiency Maine also releases performance reports annually. The latest public report is 2015.

Figure 56: 2011-2015 Electric Savings Result [11]

Year	Total (GWh)
2011	173.5
2012	226
2013	134
2014	162
2015	224
Total	919.5

[10] Efficiency Maine, "2010 Annual Report," http://www.efficiencymaine.com/docs/EMO16444_AnnualReport_2010.pdf
[11] Efficiency Maine, captured from Efficiency Maine's "Annual Reports" between 2011-2015 http://www.efficiencymaine.com/about/library/reports/

Figure 57: 2011-2015 Gas Savings Result [11]

Year	Total (MMBtu)
2011	16,115
2012	1,845
2013	12,169
2014	30,839
2015	19,274
Total	80,242

Figure 58: Gross Electricity Savings [12]

Program	Annual kWh Savings	Lifetime kWh Savings	Efficiency Maine Costs	Participant Cost	Lifetime Energy Benefit	Cost/kWh (Lifetime)	Benefit-to-Cost Ratio
Business Incentive Program Electric Measures	75,285,380	872,772,692	$17,162,905	$16,564,324	$74,374,992	$0.039	2.21
Large Customer Program Electric Measures	30,760,921	438,865,951	$6,983,439	$5,124,783	$25,297,712	$0.028	2.09
Small Business Initiative	5,409,349	70,201,736	$2,732,147	$551,767	$6,330,554	$0.047	1.93
Consumer Products Program	102,318,679	550,577,702	$10,817,327	$20,287,640	$49,871,614	$0.056	1.60
Home Energy Savings Program Electric Measures	9,032,603	162,586,854	$3,564,434	$1,079,128	$16,426,509	$0.029	3.54
Low-Income Direct Install Initiative Electric Measures	1,534,180	14,065,348	$1,232,373	$0	$1,249,631	$0.088	1.01
Cross-Cutting Strategies Electric			$863,415				
Administration - Electric			$2,136,542				
TOTAL	224,341,112	2,109,070,284	$45,492,581	$43,607,642	$173,551,012	$0.042	1.95

[12] Efficiency Maine, "FY2015 Annual Report," http://www.efficiencymaine.com/docs/2015-Efficiency-Maine-Annual-Report.pdf

Figure 59: Gross Gas Savings [12]

Program	Annual MMBtu Savings	Lifetime MMBtu Savings	Efficiency Maine Costs	Participant Cost	Lifetime Energy Benefit	Cost/MMBTu (Lifetime)	Benefit-to-Cost Ratio
Business Incentive Program Natural Gas Measures	13,057	260,887	$242,991	$66,294	$1,666,517	$1.19	5.39
Low-Income Direct Install Initiative Natural Gas Measures	636	12,728	$76,138	$0	$95,369	$5.98	1.25
Home Energy Savings Program Natural Gas Measures	5,581	127,018	$307,737	$1,100,862	$2,945,103	$11.09	2.09
Maine Advanced Building Program	1,642	32,833	$113,734	$106,360	$335,424	$6.70	1.52
Multifamily Efficiency Program	15,909	276,179	$1,414,082	$1,762,481	$4,815,091	$11.50	1.52
Business Incentive Program Other Fuels Measures	31,244	409,193	$1,095,388	$6,211,805	$10,017,712	$17.86	1.37
Large Customer Program GHG Measures	26,266	374,124	$1,808,033	$1,272,598	$6,212,210	$8.23	2.02
Low-Income Direct Install Initiative Other Fuels Measures	13,700	246,606	$700,600	$1,270,337	$4,547,475	$7.99	2.31
Home Energy Savings Program Other Fuels Measures	83,224	1,894,231	$6,309,776	$22,334,064	$43,920,697	$15.12	1.53
Renewables-Demonstration Projects			$220,923				
Cross-Cutting Strategies All Fuels			$170,894				
Administration - All Fuels			$496,969				
TOTAL	191,258	3,633,797	$12,957,266	$34,124,801	$74,555,598	$12.96	1.58

Figure 60: FY2015 Payments [12]

Use of Funds	Amount ($)
Administration-General	**2,220,441**
Residential Programs	**23,913,161**
– Administration-Res. Program	229,793
– Low Income	4,390,447
– Non-Low Income	19,292,921
Business Programs	**29,865,449**
– Administration-Bus. Program	249,884
– Small/Medium	23,138,575
– Large Custom	6,476,990
Cross-Cutting and Alternative Strategies	**1,119,422**
– Administration-C.C. Program	88,239
– Education and Awareness	27,498
– Evaluation	707,203
– Alternative Energy Program	220,926
– Innovation	75,556
Other Payments	**1,747,101**
Total Use of Funds-EMT	**58,865,574**

COST EFFECTIVENESS TESTING

TRC and PACT

Both TRC and PACT tests are presented in Efficiency Maine's annual reports. However, only TRC is used to evaluate performance. PACT is used for program planning/stakeholder relationships.

TRC and PACT by Efficiency Maine is based on "Understanding Cost effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers, A Resource of The National Action

Plan for Energy Efficiency," November 2008, http://www.epa.gov/cleanenergy/documents/suca/ cost effectiveness.pdf

TRC is used at the measure level based on net savings for introduction of measures and performance reviews and must be greater than 1.0.

Avoided Costs

TRC: The benefits included are the avoided costs of energy.

Efficiency Maine participated in the AESC Study Group, which partnered with Tabors Caramanis Rudkevich for a study on marginal energy supply costs that are avoided due to electricity, natural gas, and other fuels reductions from energy efficiency programs throughout New England. The avoided costs from the study are used by Efficiency Maine for cost effectiveness testing. The AESC Study is typically revised every three years with a mid-term update.

Major categories of benefits for electricity include reductions in:

- Quantities of resources required to meet electric demand and annual energy
- Local transmission and distribution infrastructure costs
- The quantities of capacity and energy that have to be acquired from wholesale energy and capacity markets which may cause prices in those markets to decline

The following estimates of the subsequent major components of avoided electricity costs were used:

- Avoided retail capacity
- Avoided retail energy
- Avoided RPS compliance costs
- Electricity DRIPE

Major categories of benefits for gas include:

- Reductions in gas production
- Marginal reductions in cost of delivering and distributing gas

Costs

TRC at the Program level:

- Costs incurred by program participants (Incremental Equipment Costs)
- Costs of running the energy efficiency programs (delivery and administration costs)

TRC at the Measure level:

- Costs incurred from the measure (Incremental Equipment Costs)

PACT at the Program Level:

- Costs incurred from the measure (Incremental Equipment Costs)
- Costs of running the energy efficiency programs (delivery and administration costs)
- Incentive costs

PACT at the Measure Level:

- Costs incurred from the measure (Incremental Equipment Costs)
- Incentive costs

Figure 61: Benefit- Cost Ratios: Electric Programs 2015 [12]

	Adjusted Gross Benefit-to-Cost-Ratio			Net Benefit-to-Cost-Ratio		
Programs	TRC	PACT	Last Evaluation	Net to Gross Ratio	TRC	PACT
Business Incentive Program Electric Measures	2.21	4.33	Note 2	0.71	1.83	3.08
Large Customer Program Electric Measures	2.09	3.62	Note 2	0.79	1.85	2.86
Small Business Initiative	1.93	2.32	Note 1	1.00	1.93	2.32
Consumer Products Program	1.60	4.61	2015	0.75	1.44	3.47
Home Energy Savings Program Electric Measures	3.54	4.61	Note 1	1.00	3.53	4.61
Low-Income Direct Install Initiative Electric Measures	1.01	1.01	Note 1	1.00	1.01	1.01
Total	**1.95**	**3.81**		**0.78**	**1.70**	**2.96**

Figure 62: Benefit- Cost Ratios: All Fuels and Natural Gas Programs 2015 [12]

	Adjusted Gross Benefit-to-Cost-Ratio			Net Benefit-to-Cost-Ratio		
Programs	TRC	PACT	Last Evaluation	Net to Gross Ratio	TRC	PACT
Business Incentive Program Natural Gas Measures	5.39	6.86	Note 3	0.66	3.48	4.51
Low-Income Direct Install Initiative Natural Gas Measures	1.25	1.25	2014	1.00	1.25	1.25
Home Energy Savings Program Natural Gas Measures	2.09	9.57	2011	1.00	2.08	9.57
Maine Advanced Building Program	1.52	2.95	Note 2	1.00	1.52	2.95
Multifamily Efficiency Program	1.52	3.41	Note 3	0.90	1.44	3.06
Maine Advanced Building Program	1.52	2.95	Note 1	1.00	1.52	2.95
Business Incentive Program Other Fuels Measures	1.37	9.15	Note 3	1.00	1.37	9.15
Low Income Direct Install Initiative Other Fuels Measures	2.31	6.49	Note 3	1.00	2.17	6.49
Home Energy Savings Program Other Fuels Measures	1.53	6.96	Note 3	1.00	1.52	6.96
Total	**1.58**	**5.75**		**0.97**	**1.54**	**5.57**

INCENTIVE LEVEL-SETTING

Note the Trust is in the middle of a transition on the process for setting incentives. At the time of writing this report, the MPUC had not yet decided on the process. For the first two Triennial plan periods, one of Efficiency Maine's responsibilities is to include establishing more granular incentive levels to reflect specific product types and efficacies. The goal was to ensure that program budgets are spent invested without market disruptions from prematurely exhausting or underspending budgets. As such, periodic reviews of the appropriateness of incentive levels were conducted and adjustments to financial incentives as needed are made. These decisions were made on a program by program basis as determined by the Trust.

The Trust has proposed a third plan to capture all cost effective electrical and natural gas efficiency however the process for adjusting incentives has not yet been agreed upon. In general the MPUC is concerned with the overall cost effectiveness of the programs by Efficiency Maine. The incentive level setting is at Efficiency Maine's discretion but there appears to be a threshold over which this is not the case.

Below is an overview of the process employed by Efficiency Maine when examining an incentive level for a new measure or proposing a significant change to an existing measure.

1. **Market Research/Stakeholder Engagement**
   The process starts by performing both primary and secondary market research in order to determine the measure performance metrics and costs. This will include data from utilities and consulting stakeholders such as contractors, vendors, customers and advocacy groups.

2. **Technical Reference Manual**
   Efficiency Maine has Residential TRMs and Commercial TRMs. These are documentation for energy and demand savings calculations of energy efficiency measures along with all the typically associated technology information and assumptions.
3. **Incremental Cost Design**
   Based on the market research and technology, Efficiency Maine will attempt to incentivize the incremental cost based on what is determined as a reasonable return on investment. For "Replace on Burnout" measures the incremental cost is calculated as the difference between the measure cost and that of the standard measures. For Retrofit/Direct Install measures, the incremental cost is taken as the full measure cost including the price of labour.
4. **Incentive Rate Finalized**
   Once the incremental measure cost is finalized, Efficiency Maine will set a standard incentive using the above considerations.

INCENTIVE ADMIN SPLIT

Figure 63: Electric Program Expenditures 2015 [12]

Program	Incentive	Delivery	Total
Business Incentive Program Electric Measures	$15,642,304	$1,520,601	$17,162,905
Large Customer Program Electric Measures	$6,439,194	$544,245	$6,983,439
Small Business Initiative	$2,366,729	$365,418	$2,732,147
Consumer Products Program	$8,809,467	$2,007,860	$10,817,327
Home Energy Savings Program Electric Measures	$3,086,300	$478,134	$3,564,434
Low-Income Direct Install Initiative Electric Measures	$1,105,121	$127,252	$1,232,373
Cross-Cutting Strategies Electric		$863,415	$863,415
Administration - Electric			$2,136,542
Sub Total	**$37,449,114**	**$5,906,924**	**$45,492,581**

Figure 64: Natural Gas and All Fuels Program Expenditures 2015 [12]

Program	Incentive	Delivery	Total
Business Incentive Program Natural Gas Measures	$170,847	$72,144	$242,991
Low-Income Direct Install Initiative Natural Gas Measures	$62,304	$13,834	$76,138
Home Energy Savings Program Natural Gas Measures	$275,207	$32,530	$307,737
Maine Advanced Building Program	$51,500	$62,234	$113,734
Multifamily Efficiency Program	$1,036,508	$377,574	$1,414,082
Business Incentive Program Other Fuels Measures	$976,200	$119,188	$1,095,388
Large Customer Program GHG Measures	$1,383,469	$424,565	$1,808,033
Low-Income Direct Install Initiative Other Fuels Measures	$650,600	$50,000	$700,600
Home Energy Savings Program Other Fuels Measures	$4,104,196	$2,205,579	$6,309,776
Renewables-Demonstration Projects	$220,923	$0	$220,923
Cross-Cutting Strategies All Fuels		$170,894	$170,894
Administration - All Fuels			$496,969
Sub Total	**$8,931,754**	**$3,528,542**	**$12,957,266**

EXISTING PROGRAMS [13]

Name	Target Market	Incentive Information
Home Energy Savings Program (Residential)	Residential customers who are looking to weatherize, reduce GHG, and improve overall energy efficiency such as equipment and building envelope improvement, as well as room and water heating. http://www.efficiencymaine.com/docs/HESP-Program-Manual.pdf	Air sealing with assessment: $400, a bonus of $100 provided with one envelope or heating system measure performed with an air seal and assessment Insulation: $700 per insulation (attic, wall, and basement), limit of $2,100 per building Supplemental heating system: $500 (Pellet or wood stove, or air source ductless heat pumps) Whole house heating systems: $500 (ducted air source heat pump or furnace/boiler) Ultra-low GHG whole house heating systems: 33 percent, up to $5,000 (eligible biomass boilers/furnaces) Custom projects: Tier 1 incentive: Achieve a minimum of 20 percent projected whole energy savings through any combination of savings measures and receive $1,000 per building, representing no more than 1/3 of total project cost Tier 2 incentive: Achieve a minimum of 40percent projected whole energy savings through any combination of savings measures and receive $1,500 per building, representing no more than 1/3 of total project cost PACE and unsecured energy loans: Available to most home owners, up to 15 year repayment period, fixed rate of 4.99APR, transferrable with property sale, range of loans from $6,500 to $15,000 Additional incentives available for Unitil, Maine NG, Bangor NG customers
Low Income Home Energy Savings Program (Residential)	Residential customers who are currently participating in LIHEAP looking to participate in the Home Energy Savings Program. http://www.efficiencymaine.com/docs/LIHESP-Claim-Form.pdf	Air sealing with building performance institute (BPI) assessment: $500 Insulation with BPI assessment: $1,000 each for attic, wall, and basement insulation

[13] Efficiency Maine, http://www.efficiencymaine.com/ (2016)

Name	Target Market	Incentive Information
		Other efficiency upgrades: $500 for any of; Insulate box sills, seal mobile home underbelly, repair/insulate/seal door or hatch, seal/insulate heat ducts or pipes, additional six hours of air sealing
Heat Pump Water Heater Program (Residential)	Residential customers who are looking for a new, highly efficient way to heat water. http://www.efficiencymaine.com/at-home/heat-pump-water-heater-program/	Heat pump: $500, $300 tax credit available
Appliance Rebate Program (Residential)	Residential customers who are looking to purchase new ENERGY STAR Certified appliances. http://www.efficiencymaine.com/at-home/appliancerebate-program/	Dehumidifier: $25 Room air purifier: $50 Clothes washer: $50
Lighting Program (Residential)	Customers who are looking to replace their lighting with CFL and LED bulbs.	Efficiency Maine partners with manufacturers and retailers to reduce the price of energy efficient lighting products for Maine consumers. The price vary on the store, currently the cheapest LED blub costs $0.88 for a 9 watt, CFL bulb at $0.10 for a 13 watt. http://www.efficiencymaine.com/docs/EM-lighting-deals.pdf
Business Programs	Businesses looking to upgrade their equipment	Boilers and furnaces: Incentives between $1,250 to 12,500 Boiler controls and ancillary equipment: $0.75 to 1,325 per Mbtu/h Ductless Mini-split heat pump: $500 to 1,250 per system VRF system: $0.50 per sq ft http://www.efficiencymaine.com/docs/embp_HeatingSolutions_rev030316v2.pdf Lighting: Efficiency Maine partners with manufacturers and distributors to discount the price of energy efficient screw-in LED lighting products for Maine businesses Commercial Kitchen Fryer: $1,250 Broiler: $1,550 Convection oven: $750 Combination oven: $1,250 Steamer: $2,500 Griddle: $950

Name	Target Market	Incentive Information
		http://www.efficiencymaine.com/docs/EM-Natural-Gas-Kitchen-Measures.pdf
Commercial Heat Pump Program	For businesses that are looking to upgrade their heating and cooling system with highly efficient products. http://www.efficiencymaine.com/at-work/commercial-heat-pump-program/	Ductless heat pumps: $500 to $1,250
Large Customer Program	For businesses that are looking to achieve significant electricity savings. http://www.efficiencymaine.com/at-work/competitive-program/	Funding range from minimum of $50,000 to a maximum of $1 million per facility, or up to 50 percent of the total project costs. Project should save 350,000 kWh or more to be eligible. Incentive capped at $0.28/kWh. http://www.efficiencymaine.com/docs/All-Programs-Brochure.pdf#page=2
Advanced Building Program	For Maine property owners, developers, architects, and engineers looking to achieve significant energy savings with their new construction.	Prescriptive cash incentive, at $1.50 per square foot to the building owner, and $0.25 per square foot to the lead building design team (capped at $175,000). http://www.efficiencymaine.com/at-work/maine-advance-buildings/

APPENDIX A-10: MASSACHUSETTS (NATIONAL GRID)

OVERVIEW

Jurisdictional Scan	
State/Province	Massachusetts
Utility/Agency	National Grid
Fuel	Electricity, Gas
Key Contact/Interviewee	Ellen Pfeiffer
Consultant	Mayuran Srikantha

JURISDICTION OVERVIEW

Overview of Electricity Market

The following entities make up the electricity system in Massachusetts.

- National Grid
- Massachusetts Government: Office of Energy and Environmental Affairs: Department of Public Utilities (DPU)
- Mass Save®
- ISO New England (ISO-NE)
- Energy Efficiency Advisory Council
- Other Major Electric Utilities
    - Eversource Energy
    - Unitil
    - Cape Light Compact

National Grid is an investor owned utility that operates in the United Kingdom, and in parts of Massachusetts, Rhode Island and New York in the United States. National Grid provides both electricity and natural gas to customers across these three states. In conjunction with other electric utilities and natural gas companies, National Grid submits multi-year energy efficiency plans to the Department of Public Utilities, a division of the Office of Energy and Environmental Affairs in the Massachusetts government. The plans cover National Grid's forecasted activities, and budget and savings targets for the energy efficiency programs in their portfolio.

The Department of Public Utilities is responsible for the oversight of the electric power, natural gas and water utilities in Massachusetts. The oversight includes the following activities: developing alternatives to traditional regulation, monitoring service quality, regulating safety and participating in the siting of energy facilities. The Department's mission is "to ensure that utility customers are provided with the most reliable service at the lowest possible cost; to protect the public safety from transportation and gas pipeline related accidents; and to ensure that residential ratepayers' rights are protected."

Mass Save is the public-facing brand for all of Massachusetts' efficiency programs. It is an initiative that is sponsored by Massachusetts' natural gas and electric utilities and energy efficiency service providers. These sponsors include Berkshire Gas, Blackstone Gas Company, Cape Light Compact, Columbia Gas of Massachusetts, Eversource, Liberty Utilities, Unitil and National Grid. The initiative is also supported by energy efficiency service providers and the Massachusetts Department of Energy Resources. The Mass Save portfolio covers both electricity and natural gas efficiency programs throughout Massachusetts. It helps provide consistency for Massachusetts' residential and business customers.

ISO New England (IESO-NE) is the Regional Transmission Organization (RTO) that manages New England's bulk power generation and transmission system. ISO-NE has three main objectives:

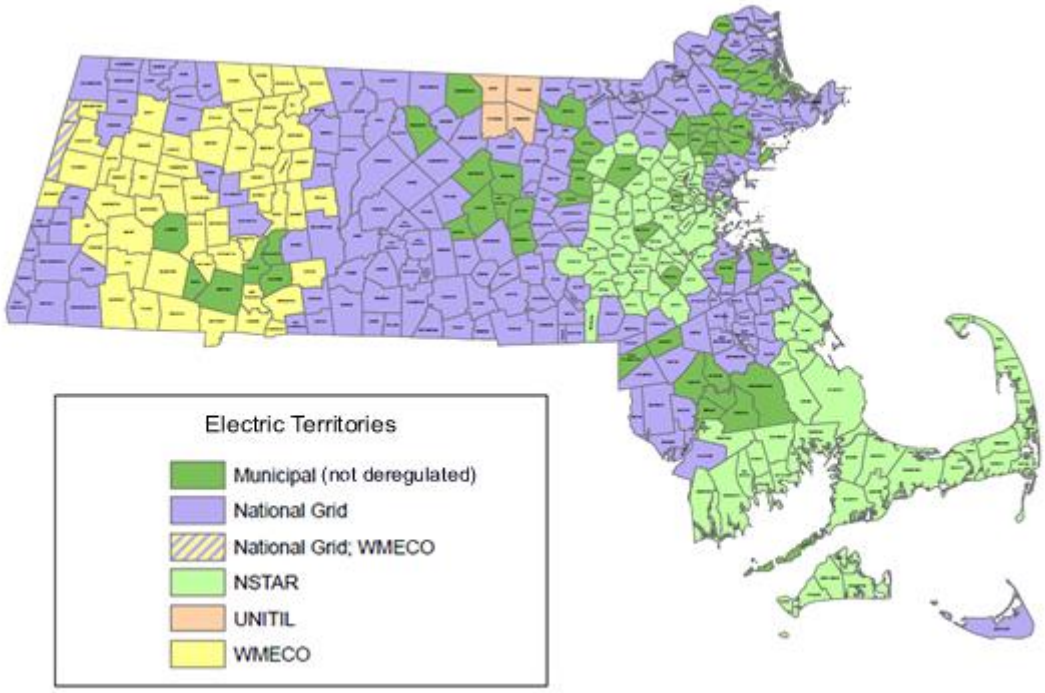
1. Ensure daily reliable operation of New England's bulk power generation and transmission system

2. Oversee and ensure fair administration of region's wholesale electricity market
3. Manage a comprehensive regional planning process

The Energy Efficiency Advisory Council (EEAC) is responsible for guiding the progress of energy efficiency in Massachusetts. Key activities include demonstrating continuing leadership in policy and program implementation, integration and innovation, achieving the full potential of the Green Communities Act, and generating significant and sustainable benefits for all Massachusetts' citizens. The EEAC's responsibilities include:

- Collaborating with the utilities on the submission on energy efficiency plans and updates
- Publishing annual results and reports; quarterly reports and monthly dashboards on progress
- Managing the annual EM&V process and other studies through the Evaluation Management Committee
- Holding monthly meetings to discuss progress, results, improvements and current projects

There are several other utilities that work with National Grid in submitting the energy efficiency plan, and in operating the efficiency programs under Mass Save. Each electric and natural gas utility has its own savings targets and budgets. The map below provides a rough demonstration of National Grid's service territory in Massachusetts[96].

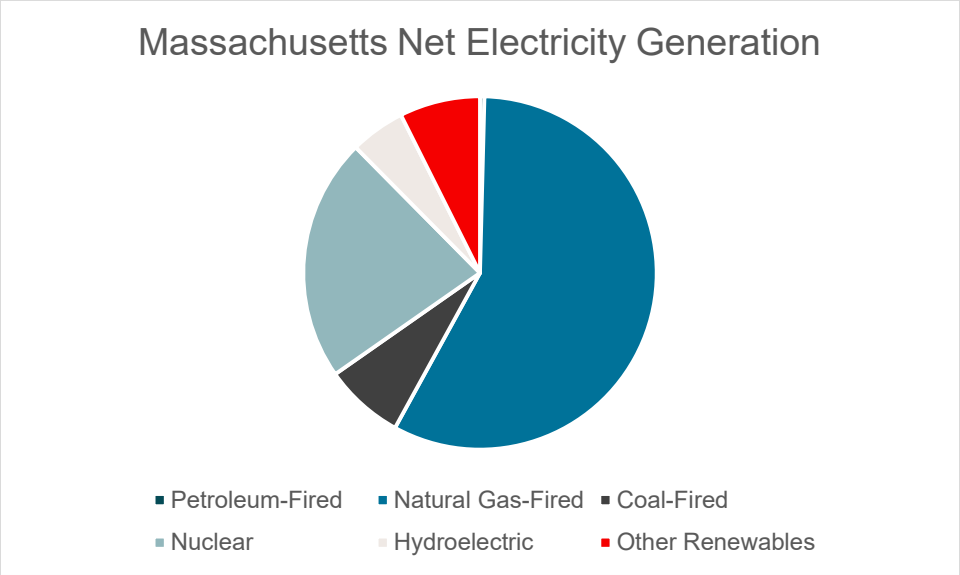


NSTAR and WMECO now operate under Eversource Energy. Cape Light Compact serves customers in Cape Code and Martha's Vineyard.

[96] http://ambitpros.com/wp-content/uploads/ambit-energy-massachusetts-electric-map.png

Electricity Generation

Massachusetts is dominated by natural gas generation[97].



Massachusetts is summer peaking with a load of 13,128 MW. Over 95 percent of the electricity generated comes from large scale generators and CHP units, while the rest comes from electric utilities. The majority of generators participate in ISO-New England's capacity market.

MASSACHUSETTS ENERGY EFFICIENCY PROGRAM INCENTIVE AND COST EFFECTIVENESS POLICY

Massachusetts is viewed as one of the leading jurisdictions for promoting energy efficiency in North America. It is ranked as the #1 jurisdiction in ACEEE's 2015 Scorecard. Massachusetts directs its utilities to design and implement programs through the Green Communities Act. The act requires electric and gas utilities to procure all cost-effective energy efficiency before more expensive supply resources. The act requires a three year planning cycle. The first cycle started in 2010. The most recent cycle (2013-2015) is expected to save 3,703 GWh by the end of 2015.

Massachusetts has the most aggressive efficiency targets in the United States, with the 2015 target being 2.6 percent of retail sales. The 2016-2018 plan calls for 4,122 GWh of savings over the three years, with a budget of $1.96 billion.[98]

National Grid's individual target and budget for 2016-2018 is 1,939 GWh and $897.6 million. The overall target is 2.94 percent of retail electricity sales.

Funding for the programs is provided through the following five sources:

1. Systems Benefit Charge ($0.0025/kWh)
2. Revenues from Forward Capacity market administered by ISO-NE
3. Revenues from cap and trade pollution control programs (Regional Greenhouse Gas Initiative)
4. Other funding sources
5. Energy Efficiency Surcharge (if required and approved by DPU)

For electricity efficiency programs, 10 percent of the total budget should be dedicated to the low income sector.

[97] http://www.eia.gov/state/?sid=MA#tabs-4
[98] http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-168%2fOrder_12816.pdf

Cost Effectiveness Testing

As per the 2016-2018 plan, there are three key elements to cost effectiveness:

1. Each program is supposed to be screened for cost effectiveness. For Massachusetts, the TRC test is used for screening. There is flexibility in what is termed a "program", but there needs to justification provided to include non-cost effective elements and provide direction on how they may be cost-effective in the future.
2. Program administration (program planning and administration costs only, not delivery costs) costs should be minimized to the fullest practicable extent
3. Program administrators will use competitive procurement processes to the fullest practicable extent

Avoided Costs

Periodically, the avoided costs are updated. The last update occurred in 2015, based on a report by Synapse Energy Economics which investigated the avoided energy supply costs for New England. Before any changes are implemented, they must be reviewed and approved by the board. The avoided costs are calculated for the entire New England Region, and then separated into different geographic areas, of which is Massachusetts.

For electricity, the major categories of benefit are[99]:

- Avoided Capacity Costs
- Avoided Energy Costs
  - These costs include the reduction in cost of renewable energy that needs to be acquired to comply with Renewable Portfolio Standards (RPS).
- Transmission and Distribution Costs
  - These are assumed at the local level.
- Capacity DRIPE
- Energy DRIPE
- Electricity Cross-Fuel DRIPE
- Avoided Non-Embedded CO_2 Costs

NATIONAL GRID – UTILITY OVERVIEW

Utility Facts

- Serves portions of Massachusetts, Rhode Island and New York
- Services a population of 3.3 million electricity customers
  - In Massachusetts, it is just under 1.1 million customers

Customer Class Breakdown

There are the following types of customers:

- Residential
- Commercial

[99] Avoided Costs - http://ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report.pdf

Retail Price of Electricity[100]

Entity	State	Ownership	Customers (Count)	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/kWh)
City of Chicopee - (MA)	MA	Municipal	26,217	455,823	55,164.7	12.10
City of Hingham - (MA)	MA	Municipal	9,626	199,687	31,215.0	15.63
City of Holyoke - (MA)	MA	Municipal	17,315	356,024	41,924.0	11.78
City of Marblehead - (MA)	MA	Municipal	10,920	105,357	15,727.0	14.93
City of Norwood - (MA)	MA	Municipal	15,414	309,614	44,810.4	14.47
City of Peabody - (MA)	MA	Municipal	26,016	504,179	64,731.5	12.84
City of Taunton	MA	Municipal	36,877	652,064	92,611.0	14.20
City of Westfield - (MA)	MA	Municipal	17,889	366,807	50,689.0	13.82
Fitchburg Gas & Elec Light Co	MA	Investor Owned	23,748	216,304	45,001.9	20.80
Massachusetts Electric Co	MA	Investor Owned	1,078,192	10,602,381	1,762,905.5	16.63
NSTAR Electric Company	MA	Investor Owned	879,498	8,805,023	1,550,537.0	17.61
Nantucket Electric Co	MA	Investor Owned	12,645	130,682	24,821.9	18.99
Town of Belmont - (MA)	MA	Municipal	11,279	125,032	23,582.0	18.86
Town of Braintree - (MA)	MA	Municipal	16,309	361,599	49,846.0	13.78
Town of Concord - (MA)	MA	Municipal	8,092	169,281	25,419.3	15.02
Town of Danvers	MA	Municipal	13,357	310,008	44,505.0	14.36
Town of Hudson - (MA)	MA	Municipal	12,695	348,102	47,133.4	13.54
Town of Ipswich - (MA)	MA	Municipal	7,054	111,088	15,727.8	14.16
Town of Littleton - (MA)	MA	Municipal	6,575	288,532	32,929.1	11.41
Town of Mansfield - (MA)	MA	Municipal	9,773	202,928	26,173.0	12.90
Town of Middleborough - (MA)	MA	Municipal	16,301	264,432	31,789.0	12.02
Town of Middleton	MA	Municipal	3,595	93,511	13,442.0	14.37
Town of North Attleborough - (MA)	MA	Municipal	14,076	229,853	34,228.0	14.89
Town of Reading - (MA)	MA	Municipal	29,641	679,152	69,533.0	10.24
Town of Shrewsbury - (MA)	MA	Municipal	15,868	278,984	31,812.0	11.40
Town of South Hadley - (MA)	MA	Municipal	8,059	111,117	16,161.1	14.54
Town of Sterling - (MA)	MA	Municipal	3,753	60,518	8,298.1	13.71
Town of Wakefield - (MA)	MA	Municipal	12,407	194,441	26,014.0	13.38
Town of Wellesley - (MA)	MA	Municipal	10,032	242,936	31,596.9	13.01
Western Massachusetts Electric Company	MA	Investor Owned	188,299	1,825,087	296,597.3	16.25

[100] http://www.eia.gov/electricity/data.cfm#sales

NATIONAL GRID - ENERGY EFFICIENCY PROGRAMMING

Savings and Expenditure[101]

In the 2013-2015 cycle, National Grid achieved the following savings with the associated expenditures. These savings and expenditures have not been through the full EM&V process yet and have not been finalized.

National Grid 2013-2015 Savings and Expenditure			
Sector	Savings (MWh)	Total Expenditure ($)	Incentive Expenditure ($)
Residential	805,157	$290,842,401	$222,323,354
Low Income	58,040	$85,604,742	$68,824,752
Commercial & Industrial	919,015	$300,079,268	$247,234,173

National Grid 2013-2015 Incentive to Total Program Spending and Spending per kWh Ratios		
Sector	Incentive to Total Program Spending Ratio	Spending per kWh Ratio
Residential	76 percent	$0.361/kWh
Low Income	80 percent	$1.475/kWh
Commercial & Industrial	82 percent	$0.327/kWh

Cost Effectiveness

National Grid's cost effectiveness results for 2013-2015 are as follows:

National Grid 2013-2015 Cost Effectiveness Results	
Expected TRC	3.69[102]
Actual TRC	Not Available

FUTURE TARGETS

The 2016-2018 plan calls for 4,122 GWh of savings over the three years, with a budget of $1.96 billion for all of Massachusetts.[103]

National Grid's individual target and budget for 2016-2018 is 1,939 GWh and $897.6 million. The overall target is 2.94 percent of retail electricity sales.

INCENTIVE LEVEL SETTING METHODOLOGY

National Grid uses the following principles for incentive setting methodology for the electricity efficiency programs:

- Customer market research
- Technology research

[101] Data from Masssavedata.com
[102] 2013-2015 Plan: http://www.mass.gov/eea/docs/doer/energy-efficiency/statewide-electric-and-gas-three-year-plan.pdf

[103] 2016-2018 Plan: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-168%2fOrder_12816.pdf

- Supply chain and stakeholder discussion
- Top-down potential analysis
- Bottom-up participation and penetration analysis

NATIONAL GRID CORE PROGRAM OFFERINGS (RESIDENTIAL AND BUSINESS)

Program Name	Program Area	Program Measures	Links
No Cost Home Energy Assessments	Residential and Low Income	For homeowners of 1-to-4 unit homes For landlords of 1-to-4 unit homes For multifamily facilities with 5+ units For income eligible customers Online home energy assessment	http://www.masssave.com/en/residential/mass-energy-rebate
Lighting and Appliances	Residential and Low Income	• Instant Price Discounts at Participating Retailers and for Online Catalogue for qualified ENERGY STAR CFL and LED lamps and fixtures • Instant Price Discounts for Online Catalogue for qualifying advanced power strips and shower heads. • Mail-in rebate for ENERGY STAR certified room air cleaners, clothes dryers and dehumidifiers • Secondary Fridge or Freezer Retirement program	
Heating & Cooling	Residential and Low Income	• Mail-in rebate for Central Air Conditioners, Air Source Heat Pumps, Heat Pump Water Heaters and Ductless Mini-Splits • Online or mail-in rebate for wireless enabled thermostat (up to $100) and programmable thermostats (up to $25)	
Deep Energy Retrofit	Residential	• Roof upgrades ($3.00/sqft), exterior walls ($3.50/sqft) and basement insulation ($2.00/sqft) to perform better than current building code • Performance incentive of $1.75 per CFM reduced based on pre- and post- project blower door tests • Access to HEAT Loan Program if eligible (0 percent financing)	http://www.masssave.com/en/residential/offers/der-national-grid
Early Heating and Cooling Equipment Replacement Rebates	Residential	• Schedule Home Energy Assessment • Online or mail-in rebate submission after installation • Incentive details are in the Appendix	http://www.masssave.com/en/residential/heating-and-cooling/equipment-installation/early-heating-and-cooling-equipment-replacement-rebates
Insulation improvements	Residential	• 75 percent on costs of insulation up to $2,000 • Potential to receive no-cost targeted sealing of air leaks	http://www.masssave.com/en/residential/offers/weatherization

Program Name	Program Area	Program Measures	Links
Wireless Thermostat and Installation Incentive	Residential	• Select from the qualifying models, purchase up to three units at the discounted price, and have them installed at no cost	http://www.masssave.com/en/residential/offers/wireless%20thermostat%20and%20installation%20incentive
Residential New Construction	Residential	• Provides incentives from $275-$7,000 per unit for energy efficiency upgrades • Have to work with Home Energy Rating System (HERS) rater or qualifying personnel • There are prescriptive incentives and performance path incentives, plus an additional ENERGY STAR incentive if the new home receives that certification • Incentive details are in the appendix	http://www.masssave.com/en/residential/offers/rnc-high-efficiency-heating-and-water-heat-rebates http://www.masssave.com/en/residential/offers/rnc-performance-path
Large Retrofit Program	Commercial	• Provides incentives for lighting and lighting controls, variable speed drives, food service equipment, gas-fired heating and water heating equipment through online or mail-in rebate submission. Provide incentives for custom measures and energy management systems • Lighting and lighting controls are prescriptive incentives • Variable speed drive incentives are quasi-prescriptive (based on hp) • Natural gas heating and water heating incentives are prescriptive/quasi-prescriptive based on size (MBH) or AFUE rating • Food service incentives cover fryers, convection ovens, steam cookers, griddles, combination ovens, rack ovens, conveyor ovens and pre-rinse spray valves. Incentives are prescriptive • Custom incentives are available for measures that don't qualify under the prescriptive stream. Incentives are based on the economics of the project and are typically up to 50 percent of the Incremental Equipment Costs of the higher efficiency equipment • Engineering studies to assess the savings potential are offered, with the participant receiving up to 50 percent of the costs of the study • Incentives are provided for the installation of qualifying energy management systems and vending miser controls	http://www.masssave.com/en/business/incentive-programs/energy-efficiency-retrofits http://www.masssave.com/business/incentives/Energy-Management-Systems-Retrofit?p=b330695a-e24c-4929-b278-3bb1692f2612
Small Business Program	Commercial	• For customers with a demand under 300 kW, offer a free audit for identifying energy savings opportunities and up to 70 percent of the total retrofit costs for equipment such as lighting,	http://www.masssave.com/en/business/incentive-programs/small-business-

Program Name	Program Area	Program Measures	Links
		motors, refrigeration and refrigeration controls. The program also offers a 0 percent financing option.	energy-efficiency-program
New Construction/Major Renovation and Replacing Failed Equipment Program	Commercial	• Provides incentives for air compressors, chillers, lighting and lighting controls, variable speed drives, food service equipment, gas-fired heating and water heating equipment, and custom measures and sustainable office design. Incentives are provided on a prescriptive, quasi-prescriptive or performance basis. • Custom measures can receive up to 75 percent of the Incremental Equipment Cost of the installed equipment	http://www.masssave.com/en/business/incentive-programs/new-construction-renovation
Sustainable Office Design	Commercial	• The sustainable office design provides an incentive of $1.00/sqft (leased space net of common areas) for energy efficient lighting and control systems.	http://www.masssave.com/business/incentives/SOD?p=95e5021 7-eb39-4286-9ee3-9756c61b958e
Multi-Family Buildings Program	Commercial	• Eligible if owner or operator of residential building with 5 or more units. An energy assessment is offered that energy savings opportunities for the building envelope, as well as lighting and mechanical systems. • Participants can receive incentives for different upgrades. • Participants are encouraged to take advantage of the EPA's Portfolio Manager tool for benchmarking their building's performance	http://www.masssave.com/en/business/incentive-programs/multi-family-buildings

Appendix B – Consolidated Calculator/Tool Requirements

The requirements for the consolidated calculator/tool are as follows:

High Level Specifications

1. **Measure Library Section (from TRM process recommendation in report)**

This section should include the details of each measure in the portfolio, or measures being considered.

- Efficient Technology Name;
- Efficient Technology Description;
- Efficient Technology Wattage (if available);
- Efficient Technology Penetration Estimate;
- Forecast Efficient Technology Penetration Estimate (in 1 year);
- Efficient Technology Retail Price;
- Forecast Efficient Technology Retail Price (in 1 year);
- Sector;
- Customer;
- Application(s);
- Operating Hours;
- Base Case Technology Name(s);
- Base Case Technology Description(s);
- Base Case Technology Penetration(s);
- Forecast Base Case Technology Penetration(s) (in 1 year);
- Forecast Base Case Technology Retail Price(s) (in 1 year);
- Annual Operating Costs
- Annual Maintenance Costs
- Annual Fuel Costs
- Current Incremental Equipment Cost;
- Forecast Incremental Equipment Cost (in 1 year);
- Energy Savings;
- Expected Energy Savings Persistence;
- Any Program Dependent Parameters (*Should be clearly identified*);
    - Net-to-Gross (NTG) Ratio
- Measure-level TRC and PAC (*can include adders for overhead delivery costs as required*)
- PC test
- Incentive screening threshold in terms of cost to the customer;
- Incentive screening threshold in terms of the program budget and
- Incentive screening threshold in terms of cost effectiveness (From Cost Effectiveness Calculator)

2. **Cost Effectiveness Calculator Section**

This section will take the inputs from the Measure Library section, combine them with the other inputs listed below, and output a cost effectiveness forecast. This will be used to determine the incentive screening threshold in terms of cost effectiveness.

Inputs

- Avoided Supply Costs (energy and capacity);
- Local Avoided Supply Costs (energy and capacity);
- Fixed Program Administration Costs;
- Year of Implementation;
- Measure Participation;
- Variable Costs;
- Annual Operating Costs (From Measure Library);
- Annual Maintenance Costs (From Measure Library);
- Annual Fuel Costs (From Measure Library);
- Measure Energy Savings (From Measure Library);

- Measure Demand Reduction (From Measure Library);
- Measure Energy Savings Persistence (From Measure Library);
- NTG (From Measure Library);
- Measure Incremental Equipment Costs (From Measure Library);
- Discount Rate and
- Inflation Rate

Outputs

- Total Gross Energy Savings;
- Total Gross Demand Reduction;
- Total Net Energy Savings;
- Total Net Demand Reduction;
- TRC Benefits;
- TRC Costs;
- TRC Net Benefits;
- TRC Ratio;
- PAC Benefits;
- PAC Costs;
- PAC Net Benefits;
- PAC Ratio;
- PC Benefits;
- PC Costs;
- PC Test Ratio;
- Levelized Unit Cost of Energy Savings and
- Levelized Unit Cost of Demand Reduction

3. Review Protocol Section

This section will display the considerations for the frequency of review for the incentive, and help set the guidelines for the size of the incentive.

Inputs

- Incentive screening threshold in terms of Customer Cost (From Measure Library);
- Incentive screening threshold in terms of the program budget (From Measure Library);
- Incentive screening threshold in terms of cost effectiveness;
- Sector (From Measure Library);
- Program Delivery Channel;
- Financial Motivation and
- Financial Impact (from Cost Effectiveness Calculator)

Outputs

Considerations for magnitude of incentive and review protocol

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Business Energy – Instant Rebates Internal Audit Report

EfficiencyOne

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May 1, 2023

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Executive summary

Background
Objective: The objective of this audit was to identify management's compliance with EfficiencyOne's documented internal controls for the Business Energy Rebates – Instant Rebates (BER-IR) program. **Scope:** The scope of the internal audit included assessing the design and operating effectiveness of 6 key controls identified by EfficiencyOne, covering 14 control activities in EfficiencyOne's control matrix for BER-IR. The focus was to assess compliance with the EfficiencyOne's internal process, as documented in the program manual, as well as to identify whether the existing processes address the risks associated with and present in the BER-IR program. The internal audit included an assessment of the design and operating effectiveness of the BER-IR program's internal controls from January 1, 2022 to October 31, 2022. **Approach:** The work was completed in three phases: • Phase I – Project Initiation & Obtain Program Understanding • Phase II – Assessment of Design & Operating Effectiveness of Key Internal Controls *(See 'Control Listing – Controls Tested ' for listing of controls tested by IA)* • Phase III – Reporting & Wrap Up

Observations noted during the engagement were classified into one of the following categories: critical, high, moderate, low. **Appendix A** outlines the classification categories. The below provides a high-level summary of observations and recommendations that are critical, high, moderate and low. Additional information on each observation can be found within the report.

# of Observations	
Critical	0
High	0
Moderate	2
Low	2
Process Improvement Opportunity (PIO)	4

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Executive summary (cont'd)

Category	Summary observations and recommendations
Moderate	1. **Minimal Review of Rebate Level in Template:** Adjusted rebate level field within the Distributor Template is not reviewed as part of the Program Specialist's Quality Assurance (QA) review. Management should consider developing a formalized procedure for this control to ensure the data is properly reviewed prior to accepting the distributor submitted template. This procedure should include the key fields to be checked during each template review. 2. **Minimal Review of Template Claim Dates:** The claim date within the distributor template is not currently reviewed during the Program Specialist's QA checks. Also, there is no additional review of the template details after the template is accepted. As such, two samples were identified where the template included claim dates outside of appropriate date range. Management should consider leveraging excel formatting to highlight any dates outside the proper range to improve identification of improper claims.
Low	3. **Minimal Review of Distributor Added Sensors:** When sensors are added to product listings by distributors, there is currently no built in spreadsheet logic to ensure the sensors are eligible for rebates. Additionally, there is no post-addition review performed by management to validate the added sensor's eligibility. Management should consider adding an additional monthly review of the sensor product listings to validate the rebate eligibility of any newly added sensors. 4. **No Confirmation of Econoler's Evaluation Updates:** Currently, the Program Manager does not evidence completion of the Master Tracker updates required per Econoler's annual evaluation. Management should consider developing an internal process for updating current year tracking of savings from the previous year's evaluation reports, including confirmation that update has been completed within a required timeline.

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Detailed observations – Moderate risk

Observation #1 – Minimal review of rebate level in template		Moderate
Observation: The adjusted rebate level field within the Distributor Template is not reviewed as part of the Program Specialist's Quality Assurance (QA) review. After July 2022, the adjusted rebated amount is calculated for each line item within the Distributor Templates to allow the Program Specialist to ensure all rebates are under the required threshold prior to accepting the invoice. This is a new check that replaces the quarterly audit of the rebate amounts, so it is important that this is thoroughly reviewed as part of the QA checks. The QA process performed by the Program Specialist requires validation of the accuracy and eligibility of the claim information contained in the Distributor Templates and Invoices. **Business impact:** Integrity of template data could be compromised if any changes/errors are not identified during QA (prior to the payment of the invoice). If the QA is not all-encompassing of the template, rebates may be paid above the maximum rebate percentage of the sales price. As there is no longer a detective review, if the over-rebates are not identified prior to accepting the template from the distributor, then EfficiencyOne risks paying rebates above the allowed threshold.	**Recommendation**: Management should consider developing a formalized procedure for this control, including identifying the key fields that must be checked for each invoice/template review. In the procedure, the key fields required to be reviewed should include, at minimum, the invoice amount, invoice claim date, rebate level percentage, company name (to ensure eligible companies only), addresses and phone numbers (to ensure NS), and distributor SKU (to ensure no empty cells). In addition, two other practices performed should be formalized into policy, such as (1) the practices of requiring additional support on large invoice amounts to validate legitimacy and (2) identifying negative quantities sold (representing returns) and matching to the original claim to ensure rebate refund is accurate. After each of these fields is reviewed, the Program Specialist should note a tick box, checklist, or other area to document they have reviewed each field appropriately, then provide a final sign-off to indicate the full review was completed. To further enhance the effectiveness of this review, conditional formatting could be added to each template. By doing so, the Program Specialist could be able to easily identify any items not in compliance. These could include, at minimum, conditions to identify when: • a rebate amount is higher than the maximum rebate percentage • a date is outside of the 15th to 14th date range • an address or phone number is not in Nova Scotia • a claim is above the dollar threshold where additional support is required • a negative quantity (return) is present.	***Management comment**:* *Management agrees with the recommendation and has implemented the following:* • *Business Energy Rebates has developed a guide for reviewing template submissions. In addition, an actions list has been added to the templates, wherein program staff can document requests made of the partner and the outcome of the request.* • *Basic conditional formatting has been added to the templates to identify data that falls outside of the program norms for the columns suggested.* • *More complex, equation-based conditional formatting is in development for both the templates and the program tracking sheets.*
***Remediation owner**: Sheri Parks*	***Remediation date**: June 30, 2023*	

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Detailed observations – Moderate risk

Observation #2 – Minimal review of template claim dates		**Moderate**
Observation: The claim date within the distributor template is not reviewed during the Program Specialist's QA checks, which led to two samples being noted where the claim dates included dates outside of the 15th-14th date range for the respective month. There is also no additional review of the template details, such as the date, after the template is accepted by the Program Specialist. **Business impact:** Integrity of template data could be compromised if any changes/errors are not identified during QA (prior to the payment of the invoice). Two templates with claim dates outside of the appropriate range were identified during testing, resulting in two rebate payments being approved and processed for claims outside the date range. Further, if a template with a claim date outside of the appropriate period is approved, a distributor could make a second claim on the same transaction in the next month as per current process. Without improving QA, rebates for the same sale could be paid multiple times inadvertently.	**Recommendation**: Management should consider leveraging conditional formatting for both the Master Tracker and the Distributor Templates to improve the identification of improper claims. In the Distributor Templates, conditional formatting could be added to the 'Claim Date' field to highlight any dates that are outside of the 15th to 14th range for the month in question, enabling identification prior to acceptance of the invoice. In the Master Tracker, Management could also consider adding conditional formatting to the invoice numbers to identify any duplicates between months. As the same invoice number should not appear in multiple months, any duplicates in different months could be recognized as an error.	***Management comment**:* *Management agrees with the recommendation and has implemented the following:* • *Basic conditional formatting has been added to the templates and the tracking sheet to identify data (claim dates) that fall outside of the program reporting periods.* • *Additional conditional formatting has been added to the tracking sheets to identify duplicate customer invoice numbers across different months. Such duplication will trigger further discussion between program staff and the partner. This will result in either the transaction being removed OR a note will be added to the record detailing why it was approved.*
***Remediation owner**: Sheri Parks*	***Remediation date**: February 17, 2023 (Complete)*	

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Detailed observations – Low risk

Observation #3 – Minimal review of distributor added sensors		Low
Observation: There is currently no built in spreadsheet logic to ensure distributor added sensors are eligible for rebates and there is no post-addition review performed by management to validate sensor eligibility. Distributors are currently instructed to contact the program specialist to confirm eligibility; however, access still exists to add these products independently without prior approval. **Business impact:** Ineligible sensors may be added to the product listing, resulting in the rebates potentially being paid on ineligible products due to manual input with no review. Further, ineligible sensors could be input into the tab with false details, resulting in potential invalid claims from distributors.	**Recommendation**: Management should consider adding a new column to the sensor product listings for the distributor to add the link to the external website with the sensor details, along with the exact date of the addition. Each month, management should also consider reviewing the sensor product listings to identify if any new sensors were added in the month. If so, the Program Specialist should follow the link provided and review the product details for eligibility. This review should be high level, focusing on confirming the sensor exists and performs a task deemed eligible for reimbursement by EfficiencyOne.	***Management comment**: Management agrees with the recommendation and has implemented the following:* • *An additional column has been added to the Distributor Product list tab of the Distributor templates, specifically for links to additional information regarding a product and supporting its eligibility. This will provide EfficiencyOne with the evidence needed to approve the product as well as record the date of approval. This field is in addition to the COMMENTS field and the date added field, which can be completed by either the Distributor or Program Specialist.*
***Remediation owner**: Sheri Parks*	***Remediation date**: February 17, 2023 (Complete)*	

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Detailed observations – Low risk

Observation #4 – No confirmation of Econoler's evaluation updates		Low
Observation: Currently, the Program Manager does not evidence completion of the Master Tracker updates required per Econoler's annual evaluation. The Master Tracker must be updated with details from the evaluation results (line loss, free-ridership, etc) to ensure reporting amounts are accurate. **Business impact:** Without a formal confirmation process, updates to the Master Tracker may not be performed in a timely manner or performed at all, leading to the risk of operational impacts due to potential reporting inaccuracies.	**Recommendation**: Management should consider developing an internal process for updating current year tracking of savings from the previous year's evaluation reports, including confirmation that update has been completed within a required timeline.	***Management comment***: *Management agrees with the recommendation.* *A process is being developed where the 2022 program evaluation measure level adjustments will be updated in either E1's Customer Information System or the individual program tracking sheets, as applicable. Sign off will be required for each program once the updates are completed. The deadline for updates will be the end of April for each year. The process will be managed by Regulatory Affairs.*
Remediation owner: *Gina Thompson*	***Remediation date***: *April 30, 2023*	

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Process improvement opportunities

Observation #	Observation	Business Impact	Recommendation
#5 - No sign-off of Master Tracker calculation review	There is minimal documentation to evidence the calculation review of the Master Tracker was completed along with the date of occurrence. The Master Tracker is where the rebate data from the monthly distributor template submissions is recorded for use in reporting purposes.	Without documentation of the reviewer name and review date, the review may not be timely or include errors. As a result, it is possible that the review may not be performed as required each month or that the review was not timely enough to correct identified issues. Therefore, there is potential for unidentified errors in the master tracker calculations, that could lead to errors in official reporting of BER-IR program results.	Within the Master Tracker, management should consider adding a tab for sign-offs, where the person who reviews the Master Tracker can document their sign off for the month. This could enable clear evidence that the review of the calculations was completed in each month. Along with the sign-off, there could also be a column to document the date the review occurred so it can be determined whether or not the review is occurring timely enough to identify and correct issues prior to reporting deadlines.
#6 – Minimal communication of reporting amounts	There is minimal evidence of the communication that supports the individual BER-IR and BER-AR (Application Rebates) results that are combined within the Board Operating Report. One Program Manager will provide their results to the other to confirm; however, the other's reply does not contain the other's results. It was noted that confirmations alone do not provide enough information to recalculate the Operating Report amounts. For the Board Operating Report, the BER-IR and BER-AR results are presented as combined BER results, which requires the BER-IR and BER-AR Program Managers to communicate and validate accuracy of the results.	Without a two-way confirmation occurring and minimal documentation of the numbers, the amounts used in the table reported to the Board may be incorrect. This could be due to a calculation errors being made by the individual who is doing the confirmation, which can not be identified by the other as only one has the data to perform the calculation.	Management should consider breaking out the reporting amounts for BER-IR and BER-AR by program, in addition to the combined BER results. This could enable the reader of the report to gain insights into the specific performance of BER-IR and BER-AR, as well as, the overall BER program. Additionally, this may remove the need for communication of amounts between the BER Program Managers, improving the efficiency of the process and transparency into the results.
***Remediation owner(s)**: Sheri Parks (#5)* ***Remediation date(s)**: February 17, 2023 (#5)*	**Management Comment:** *(#5) A sign-off table has been added to the tracking sheets wherein, every month, prior to uploading the data to the data warehouse, the Manager can initial confirming the calculated fields are all operating as they should, and all data fields are complete, with no #NAs, #REFs, blanks, etc.* **Management Comment:** *(#6) Management will take this recommendation into consideration. Separating the program delivery streams may be an option to be assessed in reporting. No Remediation Date or Owner at this time as recommendation is under consideration.*		

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Process improvement opportunities (cont'd)

Observation #	Observation	Business Impact	Recommendation
#7 - Segregation of duties risk	It is currently possible that new product eligibility decisions could be made and approved solely by the Program Specialist or Program Manager, as there is no aspect of the new product addition process that requires the eligibility decision to be communicated internally.	Ineligible products may be approved and there is a risk that eligible products may be rejected. This could be due to errors in criteria applications that may not be identified as there is no review. For example, an ineligible product could be added in error to the approved listing.	Management should consider adding a process step where the Program Specialist sends a monthly email to the Program Manager to inform them of all newly added products for the month to ensure that additions cannot be made improperly. It is noted that the risk of ineligible non-sensor products being added by distributors is low due to the spreadsheet logic requirements; therefore, the monthly email should focus on products/models that were added by the Program Specialist, as well as, sensors.
#8 - Opportunity to improve precision in addition dates	There is currently minimal clarity in the date a product was added to the product listings for lighting, as the exact date that a product was added is not retained. With only the month and date retained as the addition date, it appears as if a product added on the 30th of the month was added at the same time as a product added on the 1st. *This is only applicable to lighting as the exact date is retained for the pumping product listing.*	There may be insufficient information regarding when an addition occurred if the exact date is required, such as distributors inquiring about addition dates to determine if they can claim the rebate. Being unable to retrieve this information when required could lead to claim disputes as a result. However, Management has noted that any disputes would be resolved prior to the payment being processed; therefore, the risk of financial impacts is low.	Management should consider adding the exact date when a product is added to the listing as this could ensure a detailed record of the addition date is retained. This could allow for the exact addition date to be readily available if needed by regulators, distributors, or other stakeholders, mitigating the risk of disputes regarding the date.
Remediation owner(s): *Sheri Parks* ***Remediation date(s)***: *February 17, 2023 (#7 & #8 Complete)*	**Management Comment:** *(#7) An additional table has been added to the tracking sheets wherein, every month, the Program Specialist notes the total number of new products either the program, or the partners, have added to their lists. If there is a significant number of products, or some that the Program Specialist feels warrants additional review, an email to the Manager will be sent. Each month, the Manager initials the NEW PRODUCT addition table to confirm awareness and if any additional follow-up is required.* **Management Comment**: *(#8) Partners have been advised that the date column now requires a formatted date, and a process step has been added to the template review.*		

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Other matters

During the review of the BER-IR Program, Internal Audit inspected the BER-IR control matrix, which identified 14 control activities. Internal Audit consolidated these control activities into 9 controls that covered all 14 activities identified in the matrix (*See 'Original Control Mapping' for mapping).* Internal Audit then met with the BER-IR Program Manager and Program Specialist to discuss the 9 controls to be tested.

Through these discussions, Internal Audit determined that 3 of the 9 identified controls were not performed as the risk was mitigated by a preventative control (C2), resulting in 6 controls remaining for testing (S*ee 'Controls Tested' for controls tested and 'Control Listing – Controls Covered by C2' for controls covered by C2*). As such, it is recommended that management reviews the BER-IR control matrix and makes any required updates to ensure the documented controls align with the controls being executed.

For example, in control C2, while the preventative review of the invoices and templates is a valuable activity, it should not be relied on as the only control to ensure claim accuracy. As the Program Specialist has to review many fields in multiple distributor templates each month, there is the possibility for human error. Therefore, there should be an additional review by the Program Manager to confirm the key fields in these templates (invoice dates, invoice amount, and rebate percentage). Management should determine if the additional review should occur on all templates each month or if a spot check of a portion of the templates each month will suffice.

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Original Control Mapping

The below table displays the mapping of controls identified by Internal Audit to the 14 control activities listed in the BER-IR Control Matrix.

Control Activity per 'Instant' Tab of '2022 BER Internal Control' File	Mapping
The Efficiency Partner distributor template is updated each month on SharePoint by the Program Specialist and consists of only eligible measures already approved by ENSC. This template is password protected therefore Efficiency Partners are not able to modify products or rebate amounts.	C1
Efficiency Partner distributor template consists of only eligible measures already approved by ENS. This template is protected therefore Efficiency Partners are not able to modify products or rebate amounts.	C1
Program Specialist reviews the template and ensures the product codes, invoice #, contractor account # are complete and that the Efficiency Partner invoice amount matches the template amount.	C2
Program Manager reviews the Master list when the specialist enters the data and checks for errors, confirms the invoice amount and products sold	C2
Program Manager signs off on the invoice and delivers to Accounts Payable	C3
Program Manager approves invoice and forwards to Service Delivery Manager to review and approve. (If greater than $50,000.000)	C3
New Product Request: Efficiency Partner submits Program Specialist verifies each measure manually for eligibility using the BER instant-rebate measure criteria as the criteria for each product typically involves unique specifications calculations and determines rebate amount.	C4
Program Specialist informs Efficiency Partner of product/measure eligibility and adds it to their reporting template	C4
Program Specialist reviews total savings and ensures calculations are correct on the Master tracker	C5
Program Manager reviews the monthly savings in the Master tracker and the BER dashboard.	C5
Line loss and free rider calculations are incorporated into the Master tracker to determine net savings and are updated annually to reflect new evaluation results	C6
Monthly savings are entered into the organization's reporting template and provided to Service Delivery Manager for review, any variance beyond 10% (+/-) requires an explanation and mitigating action to be recorded in the variance template.	C7
Quarterly audits are conducted for each Efficiency Partner. Program Specialist selects 10% of invoices for each distributor. (Usually the highest rebate amounts are selected or any others based on Program Specialists' discretion).	C8
On a quarterly basis the Program Specialist requests distributor lists prices for all existing product codes included on an Efficiency Partners rebatable products listing. Adjustments to rebates will be calculated at the Program Specialist's discretion. (Keeping in mind a 50% maximum in rebate contribution).	C9

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Control listing – Controls tested

The below table displays the controls tested by Internal Audit during the review of the BER-IR program.

#	Control description
C2	For each rebate submission, the Program Specialist reviews the template and ensures the product codes, invoice #, contractor account # are complete and that the Efficiency Partner invoice amount matches the template amount. The Specialist's work is then reviewed and approved for accuracy by the Program Manager.
C3	Each invoice received by Accounts Payable is checked for appropriate approval prior to processing payment. (Program Specialist: < $20,000; Program Manager: $20,000-$49,9999; Service Delivery Manager: $50,000-$99,999; Service Delivery Director >= $100,000).
C4	For each new product request, the Program Specialist assesses each newly requested measure manually for eligibility using the BER instant-rebate measure criteria. Newly approved measures are added to the Efficiency Partner Distributor Template on SharePoint
C5	On a monthly basis, the Program Specialist reviews the total savings to ensure calculations per the Master Tracker are correct.
C6	Annually, an evaluation of the Line Loss and Free Rider calculations is conducted and the Master Tracker is updated to reflect new evaluation results.
C7	Monthly, savings are entered into the organization's reporting template and provided to Service Delivery Manager for review and approval. Any variance beyond 10% (+/-) requires an explanation and mitigating action to be recorded in the variance template.

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Control listing – Controls covered by C2

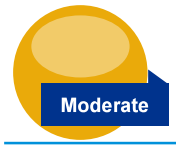
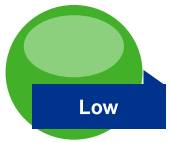
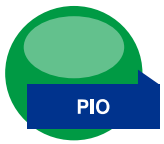
The below table displays the controls Internal Audit identified to be replaced by the preventative control C2.

#	Control description
C1	On a monthly basis, the Efficiency Partner Distributor Template on SharePoint is reviewed by a Program Specialist to validate that only measures approved by ENS are included and any ad-hoc updates to the template were processed according to policy.
C8	Quarterly audits are conducted for each Efficiency Partner. Program Specialist selects 10% of invoices for each distributor and validates the accuracy of rebates. The highest rebate amounts are selected along with any other nuanced invoices based on Program Specialists' discretion.
C9	On a quarterly basis the Program Specialist requests distributor lists prices for all existing product codes included on an Efficiency Partners rebatable products listing. Adjustments to rebates will be calculated at the Program Specialist's discretion. Note: The maximum rebate contribution is 50%.

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Appendices

Appendix A: Classification of observations

Rating	Definition	Action(s) required
	Issue represents control weaknesses, which could cause or is causing severe disruption of the process or severe adverse effect on the ability to achieve objectives .	• Requires immediate notification to the Finance Committee (FC) • Requires Senior Management attention • Requires interim action within 7-10 days, followed by a detailed plan of action to be put in place within 30 days with an expected resolution date and a substantial improvement within 90 days • Separately reported to Chairman of the FC and executive summary of report.
	Issue represents a control weakness, which could have or is having major adverse effect on the ability to achieve objectives.	• Requires prompt management action • Requires Senior Management attention • Requires a detailed plan of action to be put in place within 60 days with an expected resolution date and a substantial improvement within 3-6 months • Reported in executive summary of report.
	Issue represents a control weakness, which could have or is having an adverse effect on the ability to achieve objectives.	• Requires short-term management action • Requires general management attention • Requires a plan of action to be put in place within 90 days with an expected resolution date and a substantial improvement within 6-9 months • Reported in executive summary of report.
	Issue represents a minor control weakness, with minimal but reportable impact on the ability to achieve objectives.	• Requires management action within a reasonable time period • Requires process manager attention • Timeframe for action is subject to competing priorities and cost / benefit analysis, e.g. 9-12 months • Reported in executive summary of report.
	PIO (Process Improvement Opportunity) represents an identified business process area where an opportunity is present to implement a change in the process that improves efficiency, effectiveness and/or alignment with organizational objectives.	• Requires management consideration within a reasonable time period • Requires business process manager or supervisor attention • Decision for action is subject to management evaluation of the opportunity and cost / benefit analysis. • Reported in body of report.

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We had access to information up to January 13, 2022 in order to arrive at our observations but, should additional documentation or other information become available which impacts upon the observations reached in our report, we will reserve the right, if we consider it necessary, to amend our report accordingly. This report and the observations and recommendations expressed herein are valid only in the context of the whole report. Selected observations and recommendations should not be examined outside of the context of the report in its entirety.

Our observations and full report are confidential and are intended for the use of EfficiencyOne. Our review was limited to, and our recommendations are based on, the procedures conducted. The scope of our engagement was, by design, limited and therefore the observations and recommendations should be considered in the context of the procedures performed. In this capacity, we are not acting as external auditors nor value for money auditors and, accordingly, our work does not constitute an audit, examination, value for money, attestation, or specified procedures engagement in the nature of that conducted by external auditors on financial statements or other information and does not result in the expression of an opinion.

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Instant Savings Internal Audit Report

EfficiencyOne

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February 12, 2024

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Due to the inherent limitations of any internal control structure, it is possible that fraud, error or non-compliance with laws and regulations may occur and not be detected. Further, the internal control structure, within which the control procedures that have been subject to the procedures we performed operate, has not been reviewed in its entirely and, therefore, no opinion or view is expressed as to its effectiveness of the greater internal control structure. The procedures performed were not designed to detect all weaknesses in control procedures as they are not performed continuously throughout the period and the tests performed on the control procedures are on sample basis. Any projection of the evaluation of control procedures to future periods is subject to the risk that the procedures may become inadequate because of changes in conditions, or that the degree of compliance with them may deteriorate.

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Executive summary

Background

Objective:

The objective of this internal audit was to design and operating effectiveness of EfficiencyOne's documented internal controls for the Instant Savings (IS) program.

Scope:

The scope of the internal audit included assessing the design and operating effectiveness of 6 key controls identified by EfficiencyOne, covering control activities in EfficiencyOne's control matrix for Instant Savings. The focus was to assess compliance with the EfficiencyOne's internal process, as documented in the program manual, as well as to identify whether the existing processes address the risks associated with and present in the Instant Savings program.

The internal audit included an assessment of the design and operating effectiveness of the Instant Savings program's internal controls from January 1, 2022 to December 31, 2022.

Approach:

The work was completed in three phases:

- Phase I – Project Initiation & Obtain Program Understanding
- Phase II – Assessment of Design & Operating Effectiveness of Key Internal Controls *(See Appendix A for Listing of Controls Tested)*
- Phase III – Reporting

Observations noted during the engagement were classified into one of the following categories: critical, high, moderate, low. **Appendix B** outlines the classification categories. The below provides a high-level summary of observations and recommendations that are critical, high, moderate and low. Additional information on each observation can be found within the report.

# of Observations	
Critical	0
High	0
Moderate	0
Low	2
Process Improvement Opportunity (PIO)	3

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Executive summary (cont'd)

Category	Summary observations and recommendations
Low	1. **Late Data Submissions –** Large corporations have been slow in the past at submitting data for reporting to E1 on the effectiveness and total rebates honoured for each campaign that has impacted E1's forecasts and reporting on the effectiveness of each program. Management should investigate methods to ensure large retailers to submit their data in a timely manner in an effort to ensure all energy savings for a particular campaign are both captured and reported in a timely and accurate manner for upward reporting within E1. 2. **Timeliness of Product Additions–** There was one late addition to the Fall 2022 campaign product listing, which was appropriately requested by the retailer and approved by E1 staff; however, it was not added to the master product listing after the approval. Therefore, there was an eligible product that would appear ineligible on submission. Management should update the program manual to include a procedure for approving, documenting, and reconciling ad-hoc late additions to campaign SKU listings, which should include a retention policy for approval evidence of late additions.

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Detailed observations – low risk

Observation #1 – Late data submissions		Low
Observation: Large corporations have been slow in the past at submitting data for reporting to E1 on the effectiveness and total rebates honoured for each campaign that has impacted E1's forecasts and reporting on the effectiveness of each program. This occurred in March 2022 when a large retailer submitted rebate data from the late 2021 to March 2022 all at once, which caused a deviation from the forecast and budget prepared by Management. Program staff do not follow up with retailers regularly to request submission as Summerhill handles this retailer communication. Also, management noted that they intentionally limit this communication, so retailers recognize the importance of any emails they see from program staff. **Business impact:** Due to the high bargaining power of the large retailers, program staff have challenges forecasting effectively as material amounts of rebate data may be submitted late. This can make forecasts unreliable for the Instant Savings program for achieving future energy savings targets. Additionally, these late data submissions may limit management's ability to accurately report upward to E1's leadership on program effectiveness.	**Recommendation**: Management should investigate methods to ensure large retailers to submit their data in a timely manner in an effort to ensure all energy savings for a particular campaign are both captured and reported in a timely and accurate manner for upward reporting within E1. One method could be strengthening relationships with large retailers, then using these stronger relationships to emphasize the importance of timely data submission. Management should also considering performing monthly follow ups (as needed) with the large retailers to request submission.	***Management comment**: Management agrees with this recommendation. Partner relationships are the foundation of this program and are integral to its success. Retailer relationships fall within the contractual responsibilities of the Instant Savings Delivery Partner. For "one-off" missed deadlines, management is confident in the Delivery Partner's ability to communicate and enforce contractual reporting deadlines with retail partners. Chronic late-data-submitters, however, will be escalated from the delivery partner to program management for follow-up. Beginning August 7th, Management has established a 3-month submission window after which, if a retail partner has not submitted data, follow up directly by program management is warranted. Such communications will be retained and may be used as part of future partner performance reviews.*
***Remediation owner**: Program Manager*	***Remediation date**: August 7th, 2023*	

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Detailed observations – low risk (cont'd)

Observation #2 - Late product addition		Low
Observation: There was one late addition to the Fall 2022 campaign product listing, which was appropriately requested by the retailer and approved by E1 staff; however, it was not added to the master product listing after the approval. Therefore, there was an eligible product that appeared ineligible on submission. This impacted one SKU for one retailer, which had total rebates of $1,640 in the fall campaign period. This issue was identified and rebates were paid appropriately as part of the fall campaign payments. Per discussions with management, the risk the issue is not identified is low, as the Delivery Agent informs the retailer of any ineligible products which would prompt a discussion with the retailer and E1. **Business impact:** There is a risk of errors in rebate payments. In this instance, the issue was identified, so the risk is inefficiency in the process. Additionally, if the issue is not identified, there is a risk that E1 is tracking and reporting lower energy savings than were actually achieved in a timely manner. However, even if the issue is identified, reputational damage may occur over time, as retailers' may become concerned rebates on the product will not be repaid timely.	**Recommendation**: Management should update the program manual to include a procedure for approving, documenting, and reconciling ad-hoc late additions to campaign SKU listings, which should include a retention policy for approval evidence of late additions. This should also include a process for reconciling the retained approval evidence to the respective retailer's SKU listing to ensure all late additions are appropriately added to the SKU listing prior to the end of the campaign period. As a result, E1 could ensure that all energy savings are captured for all products in a timely manner with minimal follow-up with retailers needed to prove out product eligibility should it be questioned.	***Management comment**: Management agrees with this recommendation. The SKU approval process generally occurs right up to the beginning of the campaign period, and sometimes extends to the first couple of weeks of the campaign, as the campaign commences across retail locations. "Late submitted SKUs" are sent to and reviewed initially by the Delivery Partner who then passes them along to program staff for final approval. The back-and-forth communications will continue to be retained in the SKU folders for the specific retailer and the SKU information will be added to the Master SKU document immediately with notes regarding the date and details of the late submission. The revised Master SKU list will be circulated to the Delivery Partner. All communications surrounding the distribution of the Master SKU list will be retained to establish timeframes for the updates. As part of the onboarding of the new Program Manager for Instant Savings, emphasis was placed on maintaining/documenting all updates and changes made to the SKU lists by E1, by the delivery partner and by the retail partners. This process has been updated in the SKU approval process document titled "How-To Review & Approve Campaign SKU lists_SP" found here: S:\Services\RES\Efficient Products\RM program\2023 Program\SKU Lists*
***Remediation owner**: Program Manager*	***Remediation date**: September 15th, 2023*	

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Process improvement opportunities

Observation #	Observation	Business impact	Recommendation
#3 – No formal sign-off of year-round product listing updates	The monthly update of the year-round product listing is not formally approved by the Program Manager. Instead, discussions take place in a meeting and the Program Manager is included on the email to the Delivery Agent. However, there is no evidence to signify this meeting occurred. Without the formal sign-off, there is no documentation to verify the approval was granted.	Without a formal review and sign-off of the year-round product listing, there is a risk that the product updates are not properly reviewed by the Program Manager. This could lead to unauthorized updates being made to the product listing, resulting in rebates being paid for ineligible products. Further, as these listings are posted on the E1 public website, any inaccuracies in the product listing may lead to questions and concerns from retailers on data integrity.	Management should implement a sign-off by the Program Manager to signify that the year-round product listing has been reviewed and approved appropriately in an effort to validate the completeness and accuracy of the year-round product listing.
#4 – Insufficient support for tracking sheet updates	There is insufficient documentation to support the updates of Master Program Tracker for Instant Savings. The '2022 Measures & Codes Final' tab in the Master Tracker requires updates based on the evaluator's report and every column that was updated should include a reference to the report. Currently, a number of updated columns do not have references to the table/page of the evaluator's report that served as the source for the updates. Additionally, the screenshot of a referenced table was not included on the tab. This missing table was used to update the key features such as Line Loss and Net-to-Gross Ratio (NTGR). While the supporting documentation was not included, the evaluator confirmed in the 2022 audit that the Master Tracker was accurate, meaning it was updated appropriately.	Without supporting documentation and references from the evaluator's report being included in the '2022 Measures & Codes Final' tab, there is a risk that the updates processed do not agree to the required updates per the evaluator's report. This could lead to the potential for inaccuracies in the spreadsheet, resulting in overall inaccuracies in Program Reporting.	Management should ensure that all columns updated have a reference to the evaluators report as support and all referenced tables are included on the updated tab. Additionally, a review from the Program Specialist should be implemented to ensure all updates are supported, mitigating the risk of a unreferenced update. Management could also embed the entire report on the updated tab instead of including screenshots of tables to reduce the risk that a referenced table is not included.
Remediation owner(s): *#3 - Program Manager* *#4 – Program Specialist*	**Management comment – #3:** *Management implemented this process improvement in May 2023, as part of the June update process. A field has been added to each monthly product list document (N=10) where the Program Manager now adds their initials and the sign off date. This must be done prior to the distribution of the monthly lists (e.g., to the Delivery Partner, Energy Solutions Advisors and Marketing (updating website).)*		
Remediation date(s): *#3 – May 17th, 2023* *#4 – June 30th, 2023*	**Management comment – #4:** *Management implemented this PID in June 2023. All columns in the "Tracked Savings inputs" tab of the Tracking sheet now include the table and page reference from the latest evaluation. In addition, screen shots of the referenced tables are included in the tracking sheet on a separate sheet. Embedding the evaluation report into the tracking sheet is being considered.*		

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Process improvement opportunities (cont'd)

Observation #	Observation	Business impact	Recommendation
#5 – Review and Update the Instant Savings Program Manual	IA noted that the Instant Savings program manual and control grid includes processes and control activities that may no longer be applicable to the operations of the instant savings program, such as the review and approval of the monthly operating report.	There is a risk that management's activities may appears to not be in alignment with the program manual and control grid due to the outdate tasks or not current approaches being included that reflect actual processes and controls.	Management should review and update the program manual and key control grid to ensure that these documents are reflective of the true operations and control activities of the instant savings program. This will enable clear alignment between program manual and actual operations.
***Remediation owner(s)**: Program Specialist*	**Management comment:** Management agrees with this recommendation. As part of the annual update to the program manual, the controls were updated to reflect the controls listed in Appendix A of this document.		
***Remediation date(s)**: August 10th, 2023*			

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Other matters – Maximizing Savings on Emerging Products

Background:

- The Instant Savings program is at risk of missing opportunities to achieve enhanced energy savings that could be realized from new and emerging products in the market, as program staff do not currently review the external market in detail for new energy efficient products that could be added to the eligible product listing.
- E1 leverages both an internal engineering team and evaluator reports to review the effectiveness of the program's current offerings.
- There is no future-looking market review conducted to identify potential new listings to be added. Without a future-focused market analysis conducted regularly on new and emerging energy-efficient trends in the market, E1 may not be leveraging the Instant Savings program's energy savings capabilities to its full potential, but rather on a reactive and case-by-case basis monitoring eligibility requests from individual retailers.

.

Process Improvements:

Management should implement a regular review of the external market to identify new energy efficient emerging trends and products that are available or soon to be available. This could enable program staff to perform an eligibility assessment on these new products/measures in advance of being asked by retailers to review for addition and to realize the maximum amount of energy savings timely.

Management Comments:

For maximizing energy savings, there is a future looking assessment being conducted through our 2026-2030 DSM Planning process which is underway. Identification of new measures is part of the process and any new measures can be implemented prior to 2026.

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Appendices

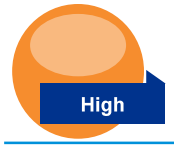
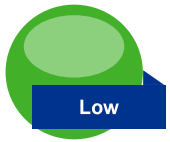
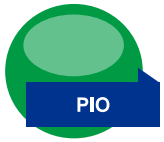
Appendix A: Control listing – Controls tested

Internal Audit tested the below Instant Savings controls to develop the observations noted in this report.

#	Control description
C1	Semi-Annually, prior to a new campaign, Program Staff review the listing of retailer requested products submitted by the Delivery Agent (DA) to validate the eligibility of products. If an ineligible product is included on the list, program staff return the list to the DA with flags of products to be removed. The DA submits the final draft listing to the Program Manager for review and approval, then once approved, the DA distributes the list to E1 and retailers. If an ad-hoc change is requested by the distributors after approval of the final listing, then program staff review the request and updated the list as needed.
C2	On a monthly basis, the internal listing of year-round eligible products is reviewed and updated by program staff. The listing is then distributed to the Delivery Agent to use when assessing project eligibility.
C3	After each campaign period, retailers submit sales and rebate data to Delivery Agent (DA) within 30 days for review. The DA reviews and compiles the data into the E1 tracking sheet template for submission to E1 along with a sample of source data. The program staff reviews the template and performs spot checks to the source data to assess project eligibility. If ineligible product is identified, the program staff returns the sheet to DA for correction.
C4	On a monthly basis, the DA compiles the data into the E1 tracking sheet template and submits to E1 . The program staff reviews the template for completeness and accuracy. If issues are identified, then program staff returns the tracking sheet to DA for correction.
C5	For each tracking sheet submission by the delivery agent (DA), the Program Manager reviews the submission to ensure data entry was performed correctly. The Program Manager totals the products sold and enters this into the overall program tracking sheet where savings are automatically re-calculated. The Program Manager cross references total savings between the monthly tracking sheet and the overall tracking sheet to validate accuracy.
C6	For each invoice payment to the Delivery Agent (DA), the Program Manager compares the invoice amount to the tracking sheet amount to confirm alignment. If any discrepancies, the Program Manager investigates and contacts the DA to resolve. Once approved, the Program Manager codes the invoice for payment and sends for processing. If the invoice is over $25,000, the Service Delivery Manager must approve the invoice and if over $100,000 the Service Delivery Director must approved the invoice.

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Appendix B: Classification of observations

Rating	Definition	Action(s) required
	Issue represents control weaknesses, which could cause or is causing severe disruption of the process or severe adverse effect on the ability to achieve objectives .	• Requires immediate notification to the Finance Committee (FC) • Requires Senior Management attention • Requires interim action within 7-10 days, followed by a detailed plan of action to be put in place within 30 days with an expected resolution date and a substantial improvement within 90 days • Separately reported to Chairman of the FC and executive summary of report.
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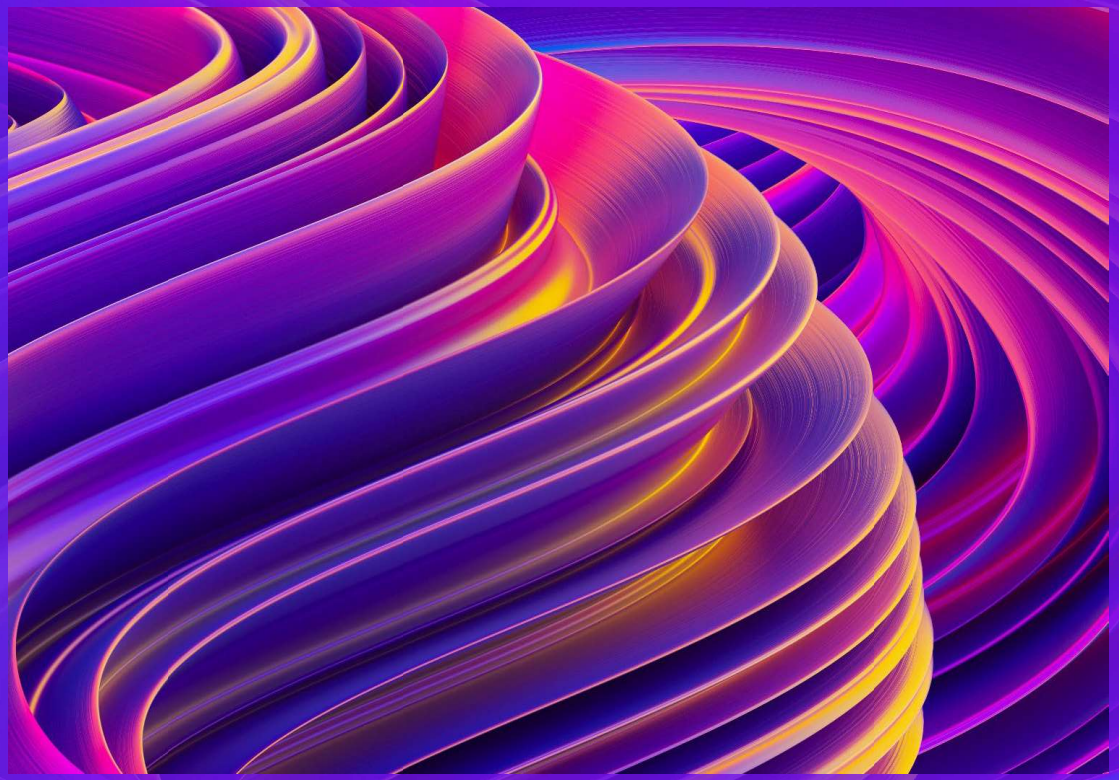
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Internal Audit: HR Recruitment and Retention



EfficiencyOne

October 30, 2025

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Background and engagement overview



Background:

As EfficiencyOne's internal auditors, KPMG was engaged to review attraction and retention processes, policies and programs to identify opportunities for the organization to implement leading practices.

Engagement overview:

Central to this review was the application of KPMG's Employee Value Proposition (EVP) Framework. This allowed us to take a structured approach to reviewing practices and identify areas for enhancement aligned to EfficiencyOne's organizational objectives.

Stakeholders engaged:

The Human Resources (HR) Department in addition to the Executive Leadership Team (ELT) contributed to the material, inputs and insights required to conduct the review and develop the report. ELT provided direction in terms of the priority areas to strengthen alignment with the organization's key priorities and goals.

The Board's Finance Committee provided insights during the March 7th, 2025 meeting.

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Areas of focus



Areas of focus:

KPMG's Employee Value Proposition framework was used to review EfficiencyOne's attraction and retention practices and offer recommendations.

Diversity, Equity and Inclusion (DEI) is a part of the framework. E1's commitment in this area was evidenced by their established representation targets and DEI policy. DEI goes beyond attraction and retention, a comprehensive DEI review independent of this audit is recommended as it would allow for a deeper understanding of the extent to which it is effectively embedded across the organization. This type of review would further identify strengths and opportunities related to DEI.

Out of scope:

Due to the advisory nature of this engagement, a formal audit of protocols and processes was not completed. KPMG will not review certain areas in detail: as part of this engagement. This includes but is not limited to:

- Assessing the operating effectiveness of HR activities and services through the testing of internal audit procedures (e.g. adherence to the formal processes)
- Assessing the competencies and/or performance of E1's workforce
- Comprehensive review of HR policies and procedures
- How applicants are selected to move through the talent acquisition process
- Comprehensive review of compensation.

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Findings & recommendations



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Overview of opportunity areas & recommendations

KPMG engaged the HR Department and ELT in prioritization exercises to identify key opportunity areas. These are areas within EfficiencyOne's talent attraction and retention practices where there is potential for enhancement and increased alignment with the organization's overarching objectives. The four opportunity areas and corresponding recommendations outlined below have been developed to support E1's future performance and success.

Culture of communication	Career development	Digital enablement	Talent acquisition
CC1: Communication strategy	CD1: Succession planning strategy	DE1: Process automation	TA1: Employee referral program
CC2: Leadership listening sessions	CD2: Career pathing framework	DE2: Digital modernization and adoption roadmap	TA2: Interviews with successful mid-level engineering candidates
CC3: Transparent employee input guidelines	CD3: Modular learning	DE3: Embedding change management	
	CD4: Formal recognition program	DE4: Change leadership	
	CD5: Performance management system		

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Findings & recommendations: Culture of communication

The table below outlines key findings and recommendations derived from our documentation review.

Element	Findings	Recommendations
 Culture of communication	• **Awareness and accessibility of information:** Access to information (e.g., policies, processes, programs, benefits etc) is not streamlined. It can be time consuming to find certain information and this contributes to inefficiency. This also contributes to a lack of clarity and understanding when it comes to policies, processes and programs in place within the organization which can lead to low uptake. • **Employee input practices:** Employees value the opportunities currently available to provide input into the organization. These include the annual survey and sessions with leadership. These types of practices contribute to an engaged workforce and increase trust in leadership. This can be particularly important during times of change, and when difficult decisions are being made across the organization. • **Consideration of employee input:** Employee comments reveal a divergence in perceptions regarding the acknowledgment of employee input. While some individuals feel that their contributions are taken into account and acted upon, others express concerns that negative feedback is frequently disregarded and not addressed in a meaningful way. These types of negative perceptions can breed mistrust in leadership which can ultimately impact buy-in and uptake of leadership decisions and initiatives.	➢ **CC1: Communication strategy:** Develop an internal communication strategy to define communication goals, communication channels, target audiences, and key messaging. It should include targeted communication campaigns to amplify key information about critical policies, benefits, and development opportunities using a variety of channels. It should also include a digital knowledge hub with intuitive navigation and search functionality to serve as a central repository for all employee-related information. This can be hosted within the upcoming Human Resources Information System (HRIS). This strategy can enable efficiency in accessing and understanding critical organizational information and should be led by E1's Corporate Communications group in consultation with HR. ➢ **CC2: Leadership and Board listening sessions:** Continue with and periodically assess the existing practice of executive leadership engagement sessions with teams. Determine the extent to which the scope of the sessions are feasible with the current members of ELT involved. Consider evolving the approach as necessary. This could involve including other leaders, adjusting the cadence, and/or considering what role the board may play. These are valuable sessions to keep a pulse on emerging areas of concern in the organization in real time. ➢ **CC3: Transparent employee input guidelines**: Develop and share guidelines regarding how employee input will be both collected (e.g., annual survey, reverse mentorship, listening sessions) and addressed (e.g., what type of input will be acted upon by leadership, and when and how this will happen). This will help manage employee expectations and maintain trust in leadership decision making.

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Findings & recommendations: Career development (1/2)

The table below outlines key findings and recommendations derived from our documentation review.

Element	Findings	Recommendations
 Career development	• **Succession planning:** While succession planning discussions for the CEO role have occurred at the board level, there is currently no comprehensive succession planning strategy in place. This can pose a risk for business continuity and resilience. Succession planning supports smooth transitions during leadership changes and minimizes disruptions to operations. It also facilitates knowledge retention, particularly as it relates to critical institutional knowledge. • **Career pathing:** A career pathing framework is not currently in place. Employees indicate a lack of clarity with regard to what paths and opportunities exist within the organization. A lack of clear paths for advancement can stunt development, motivation, overall organizational capacity and ultimately performance and innovation. • **Learning and workloads:** While EfficiencyOne supports the learning and development of its workforce, at times, workload can inhibit the extent to which employees participate in educational activities. A lack of learning and development across the workforce can negatively impact organizational capacity, performance, innovation and talent development overall.	➢ **CD1: Succession planning strategy:** Develop a succession planning strategy to build a pipeline of internal talent for key roles. This should involve identifying critical positions and their competencies, assessing potential successors, training talent accordingly, and implementing knowledge transfer plans through mentoring or job-shadowing. ➢ **CD2: Career pathing framework:** Develop and implement a career pathing framework to clearly define the progression of roles and their required skills and competences. Key elements should include: skill and competency maps; clear career levels; growth paths; alignment with the organization's strategic objectives and future needs; and integration with the performance management and learning programs. This provides employees with a roadmap for growth and advancement within the organization while aligning individual aspirations with organizational goals. ➢ **CD3: Modular learning:** Develop a flexible, modular learning program that accommodates different modalities, length, intensity, and scheduling of learning and training. This can include a mix of microlearning (short, focused learning units), self-paced online courses, on-demand resources, or in-person instructor-led courses. Modules can be externally or internally developed. Some learning options can be made available via a learning hub (i.e., in the forthcoming HRIS platform when available). This will help enable more employees to complete targeted learning and training. This can ultimately contribute to organizational capacity development, and support succession planning goals.

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Findings & recommendations: Career development (2/2)

The table below outlines key findings and recommendations derived from our documentation review.

Element	Findings	Recommendations
 Career development	• **Recognition program:** No recognition program was observed in our documentation review. Recognition programs can drive organizational performance by boosting employee motivation, engagement and productivity. By fostering a culture of appreciation, these programs can also encourage employees to align their efforts with organizational goals. • **Performance reviews**: The performance management review process incorporates organizational and team-level metrics alongside individual goal setting. Additionally, employees are expected to take accountability for their career development plan (as outlined in Professional Development and Organizational Capacity Building policy), which occurs to varying degrees across the workforce. A self-assessment component is not currently included in the performance review process. Self-assessments can help encourage greater ownership and engagement in personal career development.	➢ **CD4: Formal recognition program:** Implement a multi-faceted recognition program. A formal recognition program can include elements such as: social/public recognition from peers and/or management as well as incentives such as points, gifts or monetary rewards. This can be implemented in a phased approach, starting for example with acknowledging service anniversaries; and growing to include an intranet for public shout-outs/recognitions or a recognition software platform. (*E1 may be challenged to implement this recommendation due to how the organization is funded). ➢ **CD5: Performance management system:** Add a self-assessment component to the performance management system whereby employees evaluate their own progress and discuss with their manager. Key elements should include: reflection on accomplishments; evaluation of areas for improvement; and goal review and alignment. This can help foster accountability in one's own development plan, goals and performance.

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Findings & recommendations: Digital enablement

The table below outlines key findings and recommendations derived from our documentation review.

Element	Findings	Recommendations
 Digital enablement	• **Reliance on manual processes is inhibiting efficiency and productivity:** Many manual work processes remain in place (e.g. manually maintained spreadsheets and data sources). This can complicate simple inquiries, lead to delays and detract from staff's ability to perform the impactful elements of their roles efficiently and effectively. Manual processes are contributing to heavy workloads. • **Multiple upcoming digital implementations**: There are multiple large-scale changes planned for the organization including the implementation of new platforms in HR and Finance. With these types of change comes the need to mitigate resistance to uptake by facilitating user adoption. These types of changes can be complex and lead to disruptions in business operations when not strategically managed.	➢ **DE1: Process automation:** Develop a process automation strategy to understand and address the challenges posed by outdated systems and manual processes. This can include an audit of workflows to identify repetitive, low-impact tasks which will benefit from automation in addition to process mapping to understand and streamline current work processes. ➢ **DE2: Digital modernization and adoption roadmap:** Develop an enterprise-level, technology modernization roadmap that prioritizes updating critical systems that impact efficiency and scalability across all business areas. This should align with the organization's strategic objectives and support the evolving needs across the organization. It should address: technology selection; timing of implementation (particularly since multiple systems are being implemented); process optimization; and should be complemented with an intentional change management approach. ➢ **DE3: Embedding change management:** Embed change management practices into any organizational change initiatives. This should work in parallel with the digital modernization roadmap. This should include key change management activities: 1-stakeholder identification and engagement; 2 - identifying and understanding change impacts; 3- training; 4 - organizational readiness assessment . ➢ **DE4: Change leadership**: Aligned to a robust change management approach, identify, educate and support the capabilities needed for leaders as they lead their teams through change now and in the years ahead. This can include change-focused leadership training and a communication plan that outlines upcoming changes, and the key messaging that should accompany them.

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Findings & recommendations: Talent acquisition

The table below outlines key findings and recommendations derived from our documentation review.

Element	Findings	Recommendations
 Talent acquisition	• **Hiring process:** Current Talent acquisition processes involve posting job openings on platforms such as Career Beacon, LinkedIn, EfficiencyOne's internal site, industry portals, and career fairs. E1 also promotes their culture and benefits clearly. Overall, these strategies effectively attract new talent, taking only 19 days to fill new positions on average (days to reflects the time between the role is posted and the candidate is selected). • **Mid-level engineering talent:** Hiring mid-level engineering employees remains a challenge. These roles require a minimum of 5+ years experience, have to be licensed to practice as a professional engineer and have average salaries in the market that make it challenging for E1 to compete. These "hard-to-hire" roles take an average of 31 days to fill, with only 16% of applicants meeting qualifications on average. Selected candidates are often "stretched" to meet the requirements of their role, and are offered a mentor as support.	➢ **TA1: Employee referral program:** Develop a tiered employee referral program that offers monetary incentives to employees for successfully referring candidates who secure a position. Assign higher incentive amounts for "hard-to-hire" roles to encourage referrals for these critical vacancies (*E1 may be challenged to implement this recommendation due to how the organization is funded). ➢ **TA2: Interviews with successful mid-level engineering candidates:** Conduct interviews or focus groups with successful mid-level engineer candidates to understand why they accepted a role at E1, what was appealing about the organization and opportunity, and why they have chosen to stay at E1. While several solutions and avenues have been explored in this area, this approach has the potential to identify additional solutions.

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Appendices



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Appendix A

Our approach



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Our approach

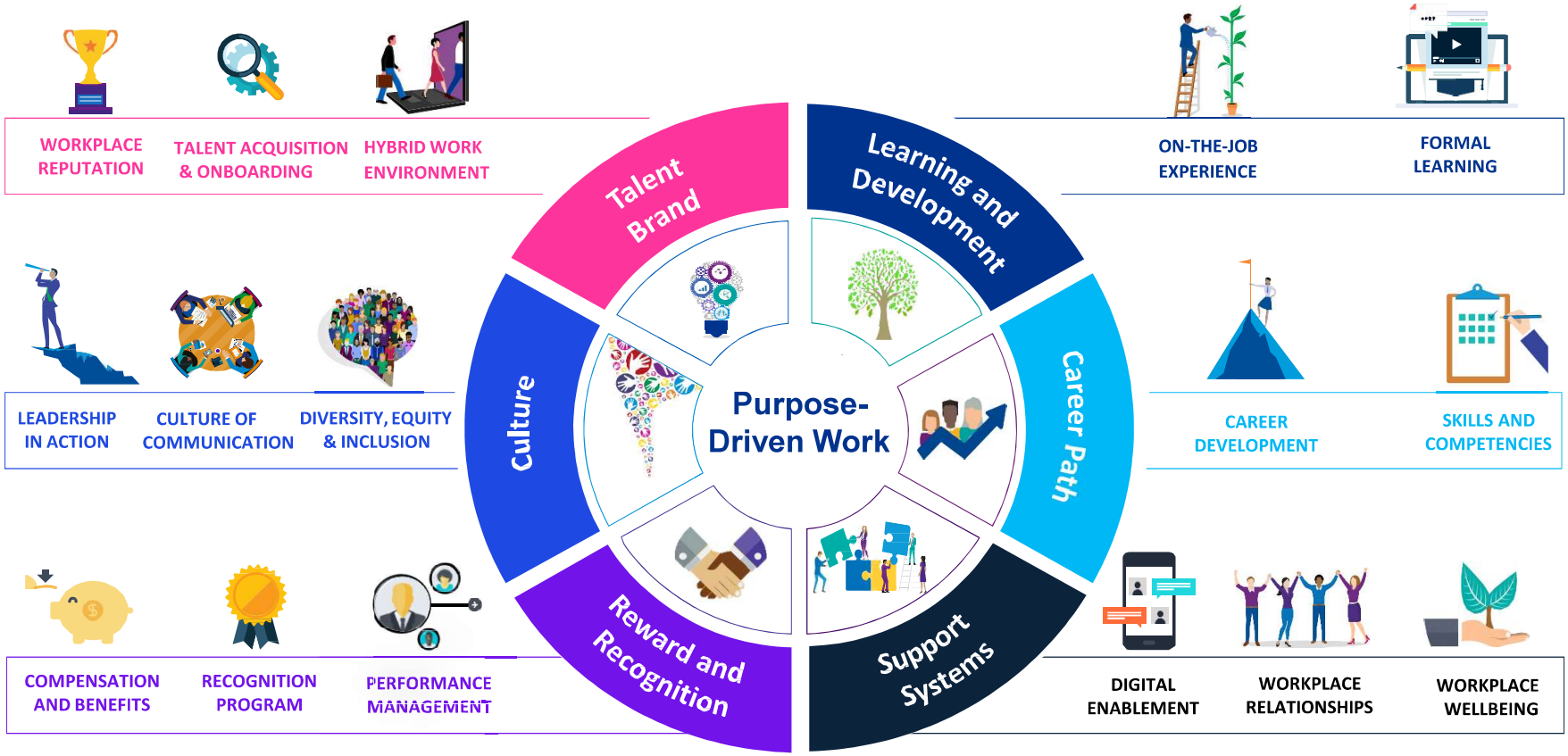
In line with EfficiencyOne's goal to improve organizational performance and foster employee engagement, our review of current attraction and retention practices identified opportunities for the organization to implement leading practices. The findings from this review served as inputs for the creation of an implementation roadmap. We executed the phases below guided by KPMG's Employee Value Proposition Framework, and in consultation with the HR Department and ELT.



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KPMG's Employee Value Proposition (EVP) framework

The diagram below illustrates KPMG's leading practice EVP framework. It consists of six key dimensions and guided the review and generation of leading practice considerations for EfficiencyOne.



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The elements of the EVP framework (1 of 2)

The following table provides a definition for each element of KPMG's EVP framework:

Category	Element	Definition
Talent brand	Workplace reputation	The extent to which the organization's reputation is one that is ethical and that of a great place to work, where employees feel inclined to openly share this opinion with others
	Talent acquisition & onboarding	The extent to which the talent acquisition & onboarding process sets employees up for success, creates excitement to join the team, and effectively welcomes and integrates them into the team, developing a level of comfort in the new environment.
	Hybrid work environment	The extend to which the organization supports remote or hybrid work arrangements.
Learning and development	Formal learning	The extent to which the organization provides employees with formal learning opportunities such as launching multiple self-directed training modules and tutorials, and establishing trainee programs and/or academies.
	On-the-job experience	The extent to which employees that feel that their role and experiences enable them to grow and upskill. The extent to which the organization provides on-the-job learning opportunities such as job shadowing, career coaching, mentoring, and professional networking.
Career path	Career development	The extent to which the organization meets career goals, and offers a clear route for progression.
	Skills and competencies	The extent to which employees feel that they are applying their unique knowledge and skills to the work they are undertaking.

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The elements of the EVP framework (2 of 2)

The following table provides a definition for each element of KPMG's EVP framework:

Category	Element	Definition
Support systems	Digital enablement	The extent to which individuals and the organization are equipped with the necessary tools, skills, and resources to effectively utilize digital technologies, fostering innovation and enhancing overall performance in a connected world.
	Workplace relationships	The degree to which employees feel that the workplace offers opportunities for personal and professional relationships that provide opportunities for growth and development and create a welcoming team environment.
	Workplace wellbeing	The extent to which the organization supports and honours employees balancing their personal and professional activities, and supporting overall wellbeing.
Reward and recognition	Compensation and benefits	The degree to which employees feel that the benefits or privileges offered, including monetary compensation and any other benefits offered by the firm (i.e. flexible work, complimentary food), meet their expectations.
	Recognition program	The informal and formal recognition programs in place including awards, awareness, and acknowledgement, that make employees feel seen and valued by their organization.
	Performance management	The extent to which employees receive real time feedback, understand how performance is evaluated, the level of support they have in this endeavor, and their feelings on whether the evaluation system is fair and equitable.
Culture	Culture of communication	The degree to which communication occurs effectively and transparently across the organization – including from leadership to employees, or between departments, teams and units.
	Leadership in action	The extent to which leadership inspires employees and makes them feel that they have a sense of purpose, can influence things and that their input is valued and appreciated. The degree to which employees feel that they have honest leaders and managers who support, challenge, and grow them.
	Diversity, equity, and inclusion	The degree to which employee feel that the workplace is inclusive, equitable, well represented by people who bring different viewpoints, principles and backgrounds, and fosters a sense of belonging for all.

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Appendix B

Summary of findings

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Positive practices

We observed a number of areas where the EfficiencyOne and the HR team appear to have successfully attained positive results as it relates to the employee experience. These achievements can serve as a foundation to build momentum for future initiatives that will continue to have a positive impact on the organization as it continues to evolve and grow.



Strong results are achieved on the employee engagement survey annually.

On the whole, employees perceive EfficiencyOne to be a good place to work. The organization takes a pro-active, well-rounded approach to addressing employee needs and concerns.

E1 maintains a healthy turnover rate relative to the market.

In 2024, the voluntary turnover rate at EfficiencyOne was 8.5%. This is on par with the industry average and below the national average. Of the employees who choose to leave, many do so maintaining positive sentiment toward E1 often acting as E1 supporters in the market.

The HR team has been proactive in identifying and acting on the evolving needs of the workforce.

The HR department has been proactive in identifying and addressing employee needs and preferences as it relates to a number of initiatives including but not limited to: streamlining the onboarding program; procuring an HRIS; and developing a career pathing framework.

E1's culture of flexibility is valued and appreciated by its workforce.

Workplace flexibility and hybrid work options are offered by E1 to support diverse employee preferences and needs. This is important to E1's workforce.

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Areas of opportunity for leading practice considerations

The leading practice considerations resulting from the attraction and retention review fall under four key opportunity areas and have been prioritized based on potential impact on the organization. They are summarized below.

01

Culture of Communication

The *Culture of Communication* findings reveal an opportunity for growth within the organization. As the organization expands, employees are eager for opportunities to provide input to leadership, and enhanced clarity regarding organizational procedures and practices. The proposed considerations aim to support organizational communication and transparency and efficiency.

02

Career Development

The *Career Development* findings indicate an opportunity for employee growth, as employees express a desire for clear career paths and additional development options. The proposed considerations focus on providing clarity in career trajectories, enhancing performance management, and introducing a recognition program. These initiatives are designed to foster individual growth and align personal development with the goals of the organization.

03

Digital Enablement

The *Digital Enablement* findings highlight a key opportunity for organizational growth, as there are currently perceived challenges with manual processes and workload management. Proposed initiatives include automating processes, and integrating change management to streamline operations and support digital transformation. These considerations aim to foster efficiency while engaging employees in the process.

04

Talent Acquisition

The *Talent Acquisition* findings highlight an opportunity for the organization to enhance its talent acquisition processes to address challenges in securing candidates for hard-to-fill roles. Proposed considerations aim to address these challenges while leveraging existing effective practices, ultimately strengthening the organization's ability to attract and secure top talent across all levels.

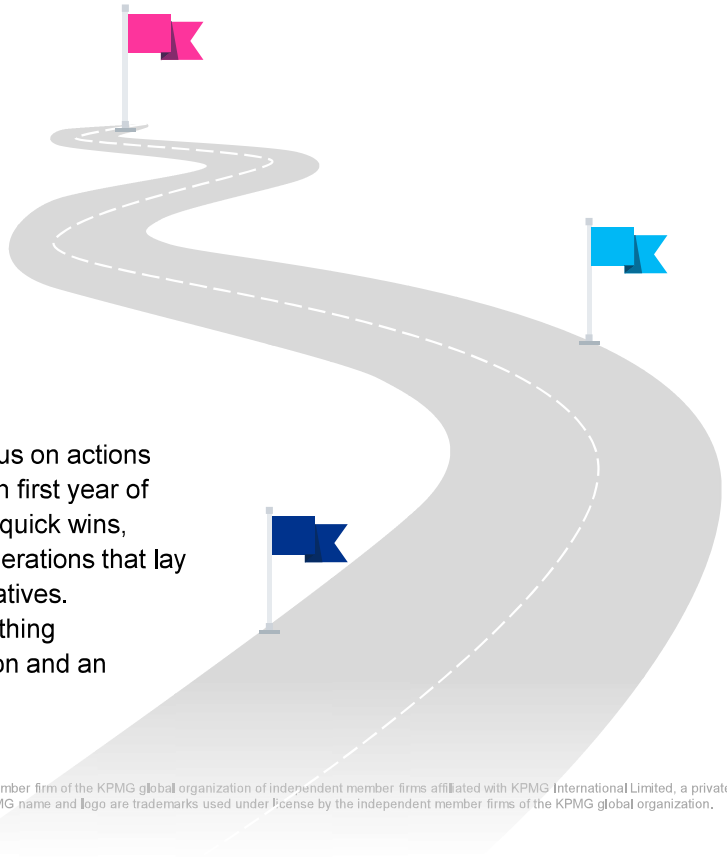
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Summary of implementation roadmap

The recommendations for EfficiencyOne have been organized into three time horizons, each defined by distinct types of considerations, varying priorities, and different levels of planning and resource requirements.

Long-term: Years 3+

Considerations in this phase require additional strategic planning and resources, are less urgent, or are dependent on the execution of considerations in previous phases. Examples include a formal recognition program and a modular learning approach.



Short term: Year 1

Short-term considerations focus on actions that are to be completed within first year of the timeline. These represent quick wins, immediate priorities, or considerations that lay the groundwork for future initiatives. Examples include a career pathing framework, process automation and an employee referral program.

Mid-term: Year 2

This phase allows EfficiencyOne to build on the quick wins achieved in the short-term while preparing for more complex initiatives that will follow. Examples include a communication strategy, a succession planning strategy and change leadership.

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Appendix C

Findings and observations (working versions)

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Context for this section

This section outlines working versions of key findings and observations from the document review and input gathered from working sessions with both the HR and ELT groups.

The following slides present detailed insights from the review process. This overview aims to provide a structured understanding of the organizational landscape as it relates to the employee experience.





Documentation review

The KPMG team conducted a document review to develop an understanding of the organization's practices related to the employee experience. This involved:

- A detailed analysis of 28 current state documents (see Appendix D for a complete list)
- Insights gathered from the 2024 Employee Engagement Research Report (July 2024).

Validation of findings and observations

Following completion of the document review, KPMG consulted with the HR and ELT teams to validate and expand upon the insights derived from the initial review. This process included:

- Regular sessions with the HR team
- Working session with the ELT to align on key findings and organizational priorities and two prioritization exercises with the HR team (See Appendix D for overviews and snapshots of working sessions):
  - Through these sessions, we identified the most impactful and relevant considerations to be formalized and carried forward into the implementation roadmap.

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Summary of findings and observations (working versions)

Below are the key findings derived from a review and analysis across the six dimensions of KPMG's Employee Value Proposition Framework.



Talent brand

EfficiencyOne promotes an employee-centric culture through flexible work arrangements, a structured talent acquisition process, and a commitment to work-life balance. There is an opportunity to address challenges related to securing candidates for hard-to-fill roles.



Learning & development

EfficiencyOne demonstrates a commitment to employee learning and development, and there is potential for employees to engage more deeply in professional growth initiatives.



Career path

While EfficiencyOne demonstrates a strong commitment to professional development, there is an opportunity to enhance clarity regarding career pathways. Additionally, by creating efficiencies through digital automation, employees will have the opportunity to be more impactful in their work.



Support systems

EfficiencyOne actively promotes strong workplace relationships and employee well-being through a variety of policies and initiatives. There is an opportunity to implement advanced scalable technologies that can streamline manual tasks and lighten workloads.



Reward & recognition

EfficiencyOne demonstrates a commitment to competitive 'total rewards', however there is an opportunity to implement an employee recognition program. Additionally, there is interest to adapt performance management to balance to incorporate self-assessment.



Culture

EfficiencyOne showcases a strong workforce culture, with emphasis placed on enhancing DEI representation.

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Talent brand

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
Workplace reputation	• **Employee-centric culture:** EfficiencyOne fosters an environment where employees feel valued and supported. This sentiment reflects the organization's dedication to accommodating individual needs. This is reinforced by policies and initiatives such as flexible and hybrid work arrangements, which contribute to a supportive culture.	➢ Results of annual employee engagement surveys are strong (e.g., 87% response rate; 88% job satisfaction) and E1 should continue with its efforts in creating an employee-centric culture. ➢ Voluntary employee turnover is healthy, aligning with national and industry standards.
Talent acquisition & Onboarding Program	• **Hiring process:** Talent acquisition involves posting job openings on platforms such as Career Beacon, LinkedIn, EfficiencyOne's internal site, industry portals, and career fairs. Current strategies effectively attract new talent overall taking 19 days to fill on average. • **Mid-level engineering talent:** Hiring mid-level engineering employees remains a challenge. These "hard-to-hire" roles take an average of 31 days to fill, with only 16% of applicants meeting qualifications on average. Selected candidates are often "stretched" to meet the requirements of their role, and are offered a mentor. • **Onboarding process:** The onboarding satisfaction rate is 94%. However, there is an opportunity to streamline this process to make it less paperwork reliant, and more efficient to complete.	➢ **IC1:** Develop a tiered employee referral program that offers monetary incentives to employees for successfully referring candidates who secure a position. Assign higher incentive amounts for "hard-to-hire" roles to encourage referrals for these critical vacancies. ➢ Continue with HR's ongoing work focused on streamlining the onboarding process. ➢ **IC2:** Interviews with successful mid-level engineering candidates: Conduct interviews or focus groups with successful mid-level engineer candidates to understand why they accepted a role at E1, what was appealing about the organization and opportunity, and why they have chosen to stay at E1. While several solutions and avenues have been explored in this area, this approach has the potential to identify additional solutions.
Hybrid work environment	• **Work-life balance:** The hybrid work environment promotes a work-life balance for employees, who generally express appreciation for this arrangement. This indicates that the flexibility of hybrid work is valued and contributes positively to employee satisfaction. • **Work-from-home policy:** Employees value and appreciate flexible and hybrid work options. However, they indicate a desire for more clarity and communication regarding hybrid work arrangements, expectations and practices. • **Physical work environment:** Employees express a need for in-office resources to support optimal performance. This applies to physical elements such as meetings spaces and space to take private calls.	➢ Continue to recognize that hybrid and remote work are a permanent practice supported by the organization.

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Learning and development

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
 Formal learning	• **Education agreement:** EfficiencyOne's education agreement emphasizes the importance of investing in the learning and development of its workforce. It demonstrates the organization's commitment to supporting continuous learning by providing financial assistance for relevant training opportunities. • **Balancing workload demands:** Employees express a keen desire to engage in training opportunities to enhance their development. However, in many instances, employees note a heavy workload restricts their ability to allocate sufficient time for these activities.	➢ **IC3:** Implement dedicated "learning hours" with dedicated KPI; or protected time specifically allocated for employee development activities. ➢ **IC4:**Develop a flexible, modular learning approach that accommodates varying workloads and schedules. This could involve a mix of microlearning (short, focused learning units), self-paced online courses, and on-demand resources that employees can access when their workload allows.
 On-the-job experience	• **Training opportunities:** A variety of on-the-job training, including cross training, job enrichment, special projects, and self-directed development, committee membership and external developmental activities are offered to support employee development. • **Mentorship and job shadowing:** A small number of employees expressed interest in professional development opportunities such as mentorship or job shadowing. However, employees also note that participation in such opportunities has at times been hindered by heavy workloads.	➢ Given that small number employee comments regarding mentorship and job shadowing, a dedicated program is not warranted at this time. However, targeted mentoring and job-shadowing should be considered as part of a succession planning strategy (see recommendation CD1).

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Career path

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
 Career development	• **Professional development policy:** EfficiencyOne's Professional Development and Organizational Capacity Building policy demonstrates a commitment to career and capacity development to support individuals and the organization as a whole. • **Clarifying career development pathways:** : A career pathing framework is not currently in place. Employees indicate a lack of clarity with regard to what career paths and opportunities exist within the organization • **Succession Planning:** There is currently no succession planning strategy in place.	➢ **IC5:** Develop and implement a career pathing framework to clearly define the progression of roles and their required skills and competences. This could involve creating job families, career ladders, and career maps that provide employees with visibility into potential career paths. ➢ It is recognized that HR has already started a Career Pathing initiative within EfficiencyOne. It is important to see this work continue to be supported as a priority within the organization. ➢ **IC6:** Establish a succession planning strategy to identify and develop internal talent for key positions. This strategy could include regular talent reviews, leadership development and training programs, and targeted mentoring.
 Skills and competencies	• **Processes to support impactful work:** Employees indicate experiencing inefficiencies in certain processes. For example, they cite reliance on multiple manually maintained spreadsheets and data sources that can complicate simple inquiries and lead to delays and oversights. This can detract from staff's ability to focus on the most meaningful and impactful aspects of their roles.	➢ **IC7:** Implement a process automation strategy to address the challenges posed by outdated systems and manual processes. This can include an audit of workflows to identify repetitive, low-impact tasks to automate.

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Support systems

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
 Digital accessibility	• **Technologies of scale:** Employees express a need for advanced scalable technologies that can effectively address the organization's evolving demands while also minimizing repetitive manual tasks. • **Growth & operational systems:** Certain processes, systems and technology supporting operations are no longer meeting the organization's increased size and demands. • **Manual processes & productivity:** Manual processes are contributing to heavy workloads with time being spent on lower-impact tasks which can be time consuming. • **Multiple upcoming digital implementations**: There are multiple large-scale changes planned for the organization including the implementation of new platforms in HR and Finance.	➢ There is an opportunity to enhance processes, systems and technology to better align with the organization's rapid growth and evolving demands. ➢ EfficiencyOne is actively advancing the implementation of new platforms (e.g., HRIS) to increase efficiency. ➢ **IC8:** Develop a process automation strategy to understand and address the challenges posed by outdated systems and manual processes. ➢ **IC9:** Develop a phased technology modernization roadmap across all business areas that prioritizes updating critical systems that impact efficiency and scalability. This should align with the organization's growth and evolving needs to support increased demands. ➢ **IC10:** Embed change management practices into any organizational change initiative. This should work in parallel with the digital modernization roadmap. This should include key change management activities: 1-stakeholder identification and engagement; 2 - identifying and understanding change impacts; 3- training; 4 - organizational readiness assessment ➢ **IC11:** Aligned to a robust Change Management methodology, identify, educate and support the capabilities needed for leaders as they lead their teams through change now and in the years ahead.
 Workplace relationships	• **Social events:** Employees value EfficiencyOne's dedication to organizing social events, including Coffee Chats and team gatherings, which contribute to building strong workplace relationships and enhancing overall well-being.	➢ No further comments were identified.

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Support systems

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
 Workplace wellbeing	• **Workload:** In the 2024 Employee Engagement Research Report, workload is identified as the fourth most critical workplace concern. 78% of respondents indicated it as critically important and a number of employees noted that, at times, it hinders their ability to participate in professional development. • **Workplace wellbeing offering:** Policies (e.g., respectful workplace policy, OH&S, parental leave, workload expectation & flexibility) in addition to programming (e.g., Canadian Mental Health Week) and mental health benefits, demonstrate E1's commitment to addressing wellbeing in the workplace. • **Employee uptake:** There is potential for increased employee engagement with the mental health and wellbeing offerings, which is currently limited by a lack of awareness and accessibility among employees.	➢ Workload has been linked to amount of manual tasks currently being performed, which add additional demands on employee's time. Much of this manual work will be automated with forthcoming technology implementations. ➢ The mental-health committee is in the process of inventorying the mental-health and wellbeing offerings available across the organization into one document. ➢ **IC12:** Support the mental health committee's development of a well-being program that consolidates and outlines existing wellbeing practices, policies, and procedures in one easily accessible location, and in a format that is easy to navigate.

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Reward & recognition

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
 Compensation & benefits	• **Salary perceptions:** EfficiencyOne has demonstrated its commitment to offering competitive salaries for all positions, ensuring that compensation aligns with the 50th percentile of the market. However, employees indicate a perceived discrepancy between their compensation and workloads, particularly as they advance in their careers. Two-thirds of employees feel that they are fairly compensated in terms of wages; a declining measure since the previous year. • **Pay transparency:** Employees express a lack of transparency concerning salary ranges for positions outside of an employee's specific pay band. • **Benefits:** Benefits made available are appreciated by employees overall. However, some have expressed an interest in coverage in specific areas such as such as IVF and orthodontic services.	➢ Addressing elements of the employee experience, such as workloads (e.g., via digitization and reductions in repetitive tasks), may contribute to improved salary perceptions. ➢ E1 has plans to go to market to explore more flexible benefit plans.
 Recognition program	• No Recognition program was observed in our documentation review.	➢ **IC13:** Implement a multi-faceted recognition approach that includes social, monetary, and peer-to-peer recognition strategies.
 Performance management	• **Goal setting:** Employees participate in a structured goal-setting process to establish their objectives for the year. Goals are iterative which provides an opportunity for employees to receive continuous feedback and make necessary adjustments. • **Performance reviews:** The Performance Management review process incorporates organizational and team-level metrics alongside individual goal setting. Additionally, employees are expected to take accountability for their career development plan (as outlined in Professional Development and Organizational Capacity Building policy), which occurs to varying degrees across the workforce.	➢ **IC14:** Add a self-assessment component to the performance management system whereby employees evaluate their own progress. This can help foster accountability and ownership of personal development. It can also provide a foundation upon which to discuss personal achievements, challenges, and growth opportunities.

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Culture

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
 Culture of communication	• **Awareness and accessibility of information:** Access to information (e.g., policies, processes, programs, benefits etc) is not streamlined. It can be time consuming to find certain information which contributes to inefficiency. This also contributes to a lack of clarity and understanding when it comes to policies, processes and programs in place within the organization which can lead to low uptake.	➢ As the organization has grown, opportunities have emerged to further refine communication practices to ensure optimal levels of support. ➢ **IC15:** Develop an internal communication strategy to define communication goals, communication channels, target audiences, and key messaging. Include clear KPIs. ➢ **IC16:** Launch targeted communication campaigns to amplify key information and make critical policies, benefits, and development opportunities easily accessible, understood, and memorable. ➢ **IC17:** Implement a digital knowledge hub with intuitive navigation and search functionality to serve as a central repository for all employee-related information. Include training during roll out.
 Leadership in action	• **Employee input:** Employees value the opportunities currently available to provide input into the organization. These include the annual survey and sessions with leadership. Employees express a strong desire for greater involvement in providing feedback and input to leadership. • **Consideration of employee input:** Employee comments reveal a divergence in perceptions regarding the acknowledgment of employee input. While some individuals feel that their contributions are genuinely taken into account and acted upon, others express concerns that negative feedback is frequently disregarded and not addressed in a meaningful way.	➢ **IC18:** Prior to developing or implementing new initiatives (i.e., communication channels, succession planning, digital implementations), take an intentional approach to seeking employee input to assess needs and preferences in advance of investment. ➢ **IC19:** Establish two-way communication/feedback channels (e.g. regular pulse surveys, digital feedback platforms, or in-person sessions) that go beyond annual engagement surveys. ➢ Employees appreciate the existing listening sessions offered by executive leadership, but this offering could become less feasible should the organization continue to grow. ➢ **IC20:** Expand upon existing practice of executive leadership engagement by implementing more frequent and inclusive "listening sessions" across all levels of leadership. ➢ **IC21:** Develop and clearly communicate guidelines regarding how employee input will be addressed.

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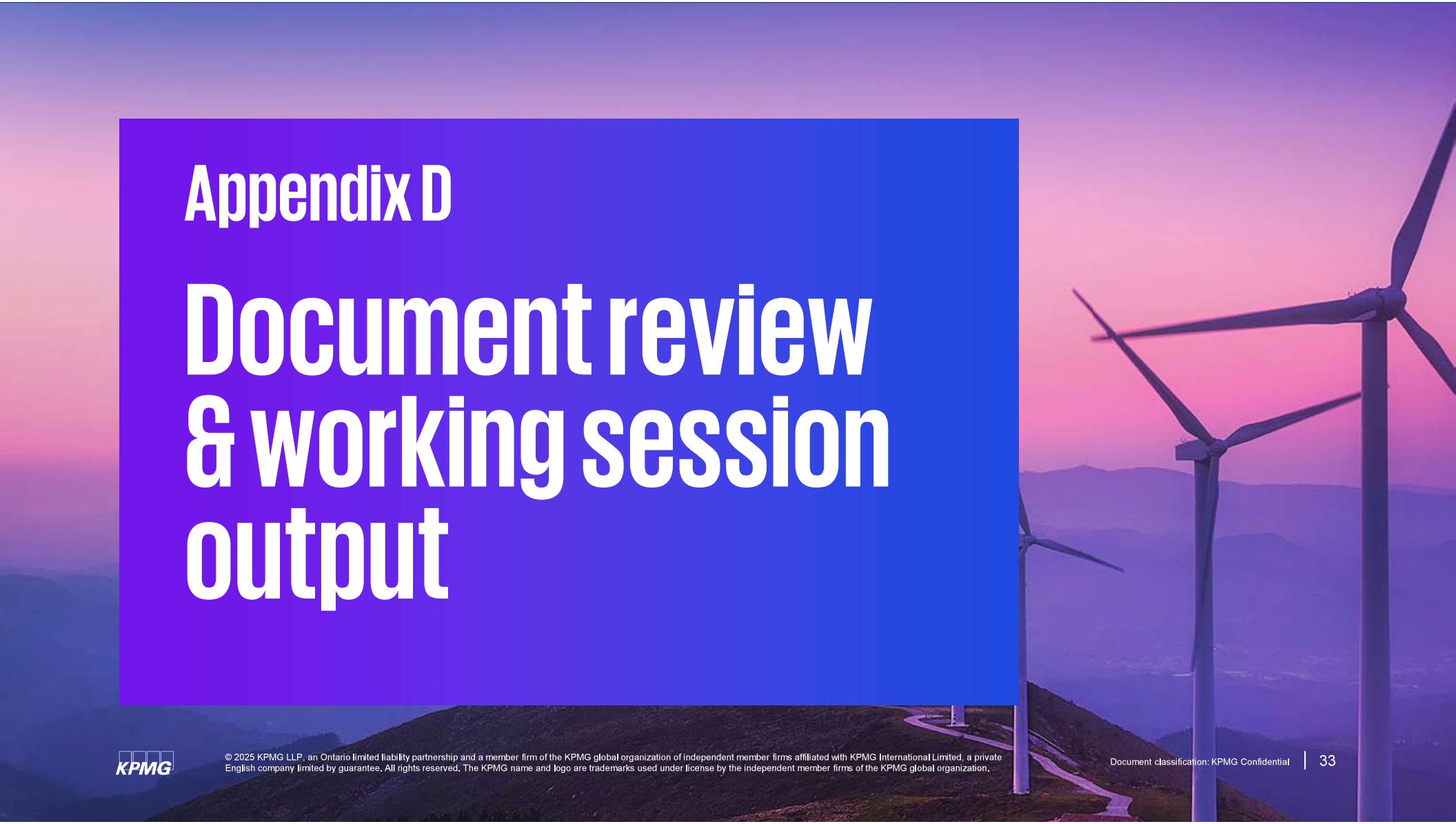
Culture

The table below outlines key findings and observations derived from the documentation review.

Element	Documentation review findings	General comments and considerations
 Diversity, equity & inclusion	• **Strong DEI foundation:** EfficiencyOne's DEI policy addresses many key DEI elements such as talent attraction, leadership support, clarity in accountability, DEI-specific learning and development, regular review and updates • **Representation targets:** Although Indigenous representation targets have not yet been achieved, the majority of representation targets have been achieved or exceeded including: women, African Nova Scotians and 'visible minorities'.	➢ While E1 appears to have a strong foundation in place to support DEI, DEI practices go beyond attraction and retention (i.e., the focus of this review) and play an important role across many facets of the organization. Conducting a comprehensive, stand-alone DEI review would allow for a deeper understanding of the extent to which DEI is effectively embedded across the organization. It would also allow for an in depth review and consideration of E1's representation targets, and further identify strengths and opportunities related to DEI at E1.

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Appendix D

Document review & working session output

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Document review list

Document list	
1. Draft 2025 Scorecard to share with E1 staff (July 2024)	15. EfficiencyOne Strategic Plan
2. Current HR Technology	16. EfficiencyOne Vacation Procedure 2017
3. E1 Code of Business Conduct and Ethics Policy – Board Approved July 27 2023	17. EfficiencyOne Workload Expectations and Flexibility Options
4. E1 Diversity Equity and Inclusion Policy – Board Approved October 26, 2023	18. Individual Development Plan
5. E1 ESG Policy – BOD Approved July 2024	19. KPMG Audit – Turnover
6. E1 Respectful Workplace Policy – Board Approved October 26 2023	20. May Corporate Scorecard and ESG
7. EfficiencyOne Compensation 2018	21. Policy Review Checklist – Oct 2024
8. EfficiencyOne Internal Guidelines for Staff – April 23 2018 – Final	22. Trakstar Goal Setting Guidelines – 2022
9. EfficiencyOne Occupational Health and Safety Policy – BOARD APPROVED 25 July 2019	23. KPMG Audit – Project Charter 2025
10. EfficiencyOne Performance Management – 2022	24. E1 Employee Exit Survey
11. EfficiencyOne Paid Holidays Procedure	25. Education agreement 2025
12. EfficiencyOne Pregnancy and Parental Leave	26. EfficiencyOne Professional Development and Organizational Capacity Building
13. EfficiencyOne Professional Development and Organizational Capacity Building	27. ENS001-1093 Verbatim Comments – Formatted
14. EfficiencyOne Social Media Procedure	28. Org Chart – November 2024

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ELT meeting recap

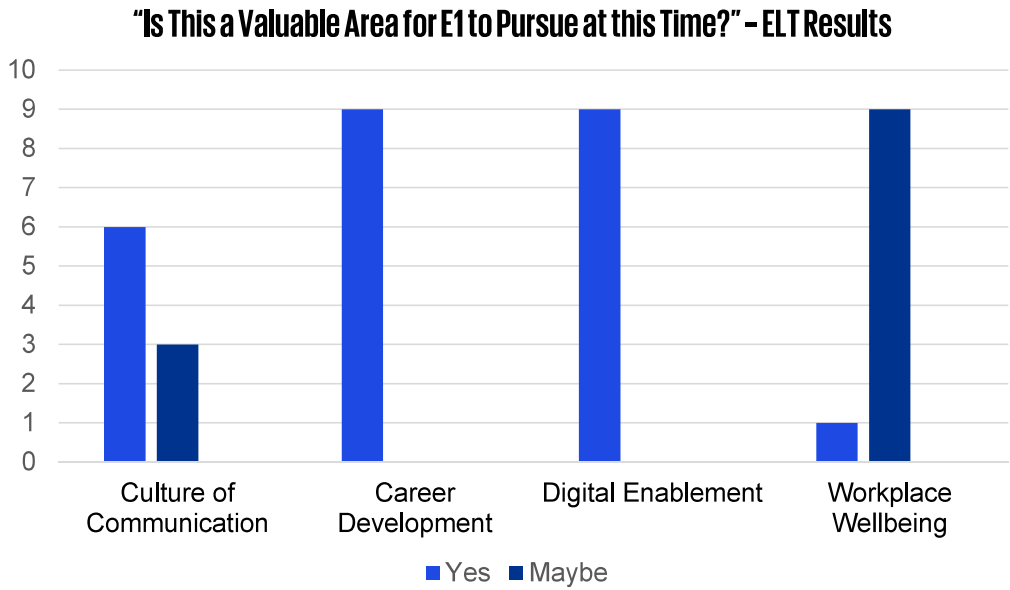
We consulted the ELT to assess and rank the strategic importance of these four key areas. The results are outlined below:

01 Digital Enablement

02 Career Development

03 Culture of Communication

04 Workplace Wellbeing



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HR working sessions: prioritization activity

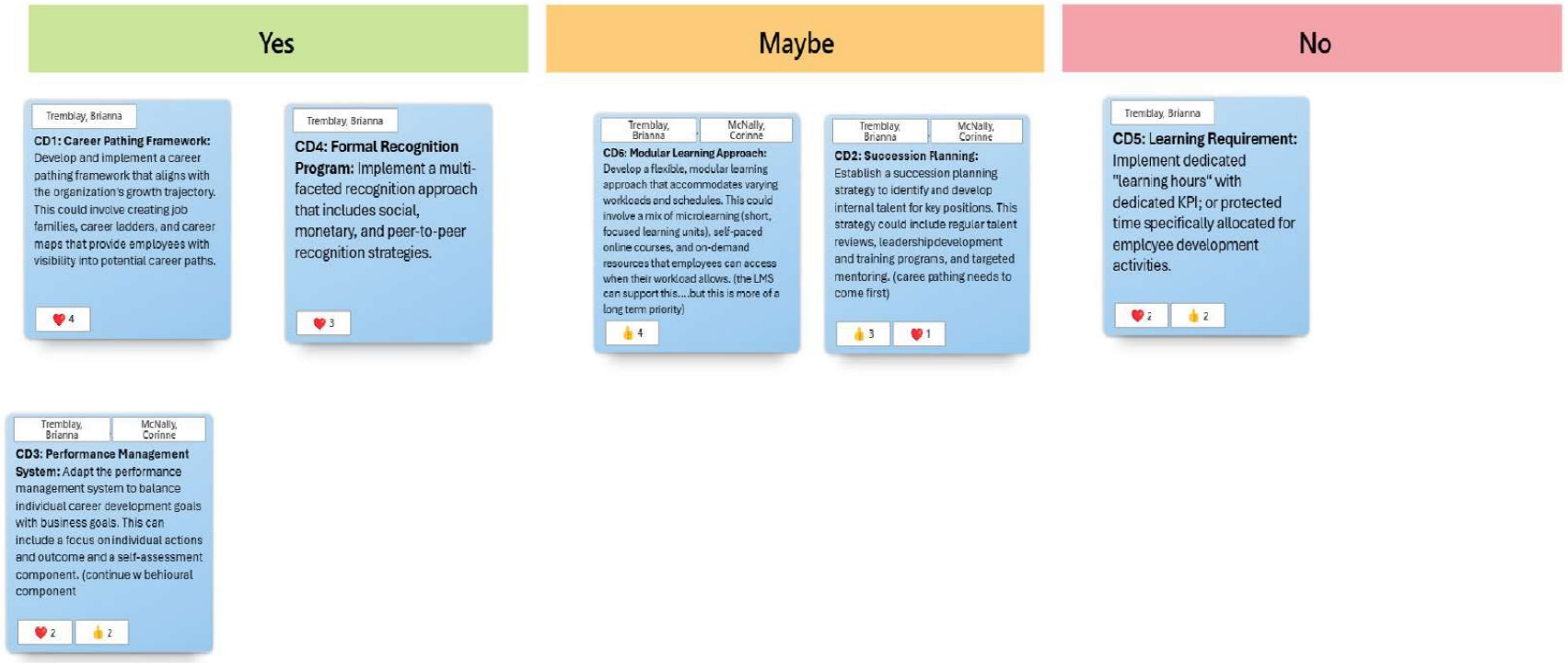
Culture of Communication



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HR working sessions: prioritization activity

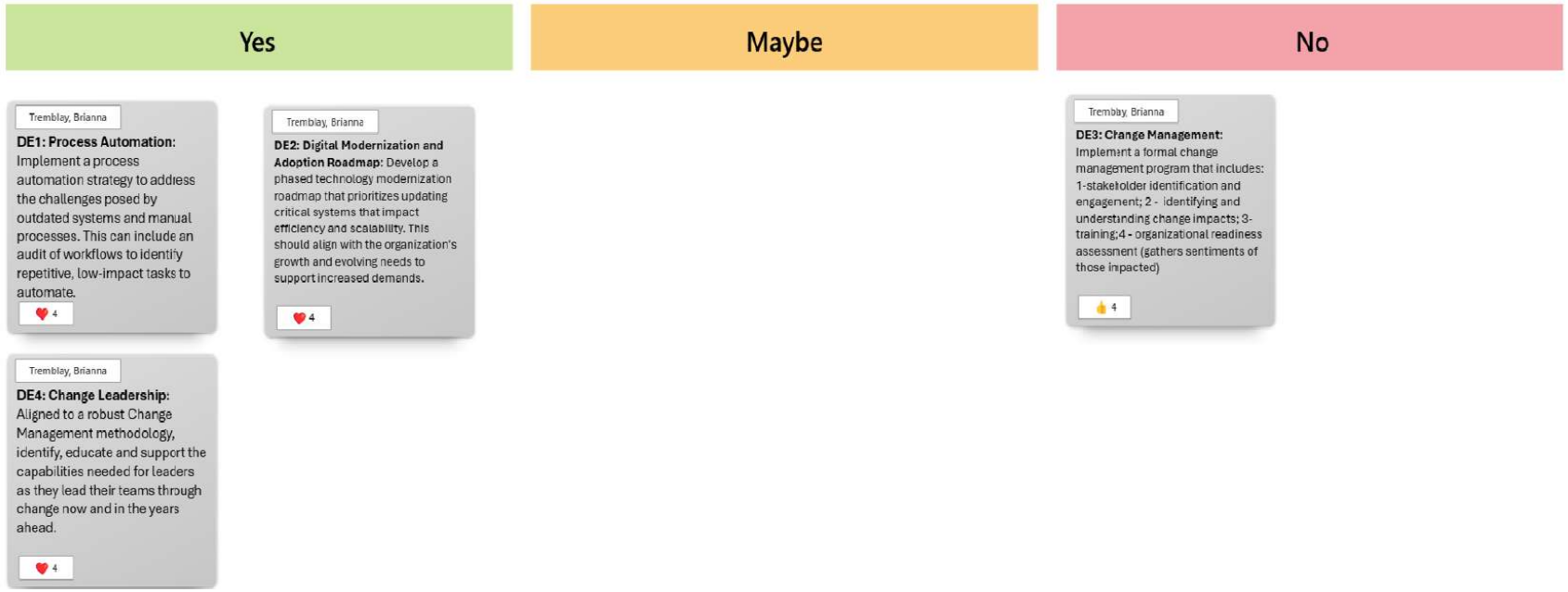
Career Development



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HR working sessions: prioritization activity

Digital Enablement



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HR working sessions: prioritization activity

Workplace Wellbeing

Yes	Maybe	No

Tremblay, Brianna

WWB1:Workplace Wellbeing Program: Support the mental health committee's development of a well-being program that consolidates and outlines existing wellbeing practices, policies, and procedures in one easily accessible location, and in a format that is easy to navigate.

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HR working sessions: implementation timeline

DRAFT: Timeline (KPMG - E1 HR: Working Session - Feb 3 2025)



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Comparison of Diversity of Program Delivery – 2023-2025 Plan, 2026 DSM Extension and 2027-2031 DSM Plan

Item	2023-2025 DSM Plan	2026 DSM Extension	2027-2031 DSM Plan
Diverse Measures	• 356 measures, with measure lives ranging from 1 to 36 years • 14 energy efficiency program components; • 2 demand response program components • decreased reliance on savings from residential light-emitting diode ("LED") lighting, and savings increase from other measures such as smart thermostats for residential baseboard heating and residential lighting controls.	• 366 measures • 12 energy efficiency program components (ended Appliance Retirement and Green Heat) • 2 demand response program components • shift in focus for Efficient Product Installation to electrician installed measures	• 341 measures • 11 energy efficiency program components • 2 demand response program components • 1 solar-pv program component
Diverse Markets	• Target markets include: o Homeowners o Renters and/or landlords o Building owners o Builders & developers o Small business o Industry o Commercial o Institutional • increasing support for low-income and equity customers with growth in investment (21% of total Plan investment)	• Continuation of 2023-2025	• Target markets include: o Homeowners o Renters and/or landlords o Building owners o Builders & developers o Small business o Industry o Commercial o Institutional • support for low-income and equity customers (dedicated low-income & equity energy savings 11% of total Residential energy savings) • Solar-PV resource is dedicated to residential customers in Mi'kmaw communities
Diverse Strategies	• offers a range of delivery strategies inclusive of technical support (such as energy assessments and feasibility studies), point-of-sale and post-	• Continuation of 2023-2025	• combination of turn-key delivery in partnership with delivery agents, contractor-based delivery, and market-enabled offerings

Item	2023-2025 DSM Plan	2026 DSM Extension	2027-2031 DSM Plan
	purchase rebates, direct installation, and self-serve participation channels • through Enabling Strategies, efforts to research and develop an appropriate market transformation approach to support E1's traditional resource acquisition model will be a key priority for 2023-2025		• offers a range of delivery strategies inclusive of technical support (such as energy assessments and feasibility studies), point-of-sale and post-purchase rebates, direct installation, and self-serve participation channels • through Enabling Strategies, efforts to pilot an appropriate market transformation approach to support E1's traditional resource acquisition model will continue in 2027–2031 through the heat pump water heater pilot

Request IR-20:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 6 "Preferred Plan Details" of the Application:

(a) Pdf pg. 62 states: "The Preferred Plan's energy efficiency resource has a first-year unit cost of $0.66/kWh and a weighted average measure life of 12.3 years, resulting in a lifetime unit cost of $0.05/kWh which is significantly lower than NS Power's average cost of fuel at the end of 2025 of $0.093/kWh."

i) Please provide a reference in the evidence filed to date showing where these numbers have been calculated.

- **If no such supporting calculations have been filed to date, please provide the calculations in spreadsheet format with all formulae intact and unaltered.**

(b) Regarding Tables 7, 8 and 9 on pdf pgs. 63, 64 and 65: Please provide a reference in the evidence filed to date showing where the numbers in the Tables have been calculated.

i) If no such supporting calculations have been filed to date, please provide the calculations in spreadsheet format with all formulae intact and unaltered.

Response IR-20:

(a) The first-year unit cost of $0.66/kWh is calculated as follows:

Total expenditures Energy Efficiency + Enabling Strategies /Total first year energy savings

$286.8 million/435.4 GWh = $0.66/kWh

Attachment 1 of EfficiencyOne's (E1) response to NSEB IR-38 provides total first year energy savings by program component for each year of the plan, which when summed equals 435.4 GWh (column X of each annual tab). Total program component expenditures for each energy efficiency program component are provided in Attachment 1 of E1's response to NSEB IR-38. Specifically, column AB on each annual tab provides the total incentive and an additional row has been added for the inclusion of Program Admin Costs which are added at the program component level and not measure level. At the bottom of each annual tab, any additional costs have been included such as Enabling Strategies investment to provide the full annual expenditures.

The lifetime unit cost of $0.05kWh is calculated as follows:
Total expenditures Energy Efficiency + Enabling Strategies /Total lifetime energy savings
$286.8 million/5,335.1 GWh = $0.05/kWh

Total lifetime energy savings are provided in Attachment 1 of E1's response to NSEB IR-38 in column Y of each annual tab.

NS Power's average cost of fuel at the end of 2025 of $0.093/kWh was taken from NS Power's Management's Discussion and Analysis for 2025. Please refer to E1's response to Synapse IR-20, Attachment 1.

i) Please refer to part (a) of this IR response.

- Please refer to part (a) of this IR response.

(b) Please refer to Attachment 1 of E1's response to NSEB IR-38 for the energy efficiency and solar-PV results and summation for the 7, 8 and 9 in Appendix A tables. Please also refer to

Attachments 2-4 of E1's response to NSEB IR-38 for demand response results as well and input assumptions for both energy efficiency and solar-PV, and demand response .

i) Please refer to part (b) of this IR response.

Request IR-21:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Pdf pg. 55 states that when E1 created its Preferred Plan, it took cost-efficiencies into consideration and a full accounting value to minimize the cost of savings. Please describe the cost-efficiencies pursued and those that were not.

Response IR-21:

In creating the proposed 2027–2031 Preferred Plan, EfficiencyOne (E1) has reduced full-time equivalent (FTE) staffing, reduced spending on Enabling Strategies, and focused resources on cost-effective program delivery. Examples include streamlining application and approval workflows to reduce administrative processing time and costs; enhancing digital delivery channels and self-serve participation options to lower per-transaction delivery costs; consolidating delivery agent contracts where possible to achieve economies of scale; and implementing data-driven program management tools that enable earlier identification of underperforming measures, allowing for timely reallocation of resources to higher-performing program components. E1 has also leveraged multi-year procurement arrangements where appropriate to secure favourable pricing and reduce transaction costs.

E1 did not pursue any cost-efficiencies which would limit E1's investment in Information Technology and Cybersecurity.

Through the selected cost-efficiencies and the subsequent reduction in full-time equivalent (FTE) staffing, E1 will achieve annual cost savings of approximately $0.9 million per year.

Request IR-22:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Please provide the annual cost savings that the Preferred Plan will achieve through the selected cost-efficiencies and those that were not pursued for each year of the Plan.

Response IR-22:

Please refer to EfficiencyOne's response to NSEB IR-21.

Request IR-23:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Pdf pg. 62 states that: "…investment level of $318.75 million for three DSM resources -– energy efficiency, demand response, solar-PV - as well as for enabling strategies;"

(a) Please explain why solar-PV, instead of other renewable generation has been included as a specific DSM resource.

(b) Please indicate whether E1 has explored other renewable energy generation resources and

i) if so, please provide details.

ii) If not, please explain the rationale.

Response IR-23:

(a) EfficiencyOne (E1) has included solar-PV at a modest scale in the proposed 2027–2031 DSM Plan to support residential Mi'kmaw customers participating in the proposed Mi'kmaw New Home Construction offer. The 2027–2031 Preferred DSM Plan's support for Mi'kmaw communities was developed directly in response to feedback from those communities who identified solar-PV as a preferred and accessible form of renewable generation. Solar-PV has been selected as a specific DSM resource - rather than other renewable energy generation resources such as wind, hydro, utility solar, and biomass - because it is uniquely suited to deliver measurable, customer-level benefits at the residential scale, is increasingly cost-effective, and can be integrated with home construction in a practical and equitable manner.

E1 has accumulated significant experience administering solar-PV programs over many years, providing a strong foundation for the delivery of the solar-PV component of the proposed 2027–2031 DSM Plan. E1 has administered solar-PV incentives through its demand side management work (e.g., Business Energy Rebates and Custom program components) and its government-funded programs (e.g., SolarHomes and Canada Greener Homes Grant). This established expertise, along with E1's existing contractor relationships and program delivery infrastructure, supports E1's ability to deliver solar-PV programming efficiently and effectively as part of the Mi'kmaw New Home Construction offer in the 2027–2031 DSM Plan.

(b) E1 has long provided support for small-scale biomass generation via wood and pellet burning equipment in program components like Home Energy Assessment. E1 did not explore the inclusion of other renewable energy generation resources in the proposed 2027–2031 DSM Plan for the reasons as described in part (a) of this IR response.

i) Please refer to part (b) of this IR response.

ii) Please refer to part (b) of this IR response.

Request IR-24:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Exhibit E-1, page 56 of 71(pdf pg. 63), Table 7: 2027-2031 Plan – Portfolio Level Insights

(a) E1 notes that dedicated low-income and energy savings as a percentage of total residential energy savings is 11%. What is the percentage of dedicated low-income and equity program costs to total residential energy efficiency program costs?

Response IR-24:

(a) Dedicated low-income and equity program component investment is 42 percent of total residential energy efficiency program investment. The calculation supporting this figure is provided in EfficiencyOne's response to AEC IR-02.

Request IR-25:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Exhibit E-1, page 57 of 71(pdf pg.64), Table 8: 2027-2031 DSM Preferred Plan Portfolio Savings and Investment:

(a) Please explain why there are progressively downward trends in "Lifetime Benefits", "First-Year Energy Savings", "Peak Demand Savings" and "Lifetime Energy Savings" in each year of the plan period?

Response IR-25:

(a) EfficiencyOne (E1) constrained the annual investment in the proposed 2027–2031 DSM Preferred Plan to the 2026 approved level of $63.75 million per year. This was a deliberate design decision to prioritize near-term affordability for Nova Scotia ratepayers while continuing to deliver long-term value. The $63.75 million annual investment is allocated between energy efficiency, demand response, and solar-PV.

Two design decisions explain the downward trends observed in Table 8 of E1's Evidence. First, as a result of BNI lighting baseline changes to LED, E1 front-loaded energy efficiency investment earlier in the Plan to capture the full savings of this lighting transition before E1 would no longer be providing customer support for those measures. Second, later in the Plan, investment in energy efficiency was shifted to accommodate the planned ramp-up in demand response, which grows from 21.1 MW of available capacity in 2027 to 29.3 MW by 2031.

As a result, first-year energy savings and peak demand savings decrease across the Plan period - from 121.5 GWh and 19.7 MW in 2027 to 65.2 GWh and 14.2 MW in 2031. Lifetime benefits and lifetime energy savings are directly correlated to those metrics and trend downward accordingly - from $175.9 million and 1,540.6 GWh in 2027 to $135.4 million and 787.1 GWh in 2031.

This downward trend reflects the allocation of investment across the Plan's DSM resources and does not represent that the value of energy efficiency is diminishing. The Preferred Plan's energy efficiency resource delivers a lifetime unit cost of $0.05/kWh, significantly below NS Power's average cost of fuel, and the portfolio achieves a Program Administrator Cost (PAC) test ratio of 2.4.

Request IR-26:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Exhibit E-1, page 58 of 71 (pdf pg.65), Table 9: 2027-2031 DSM Preferred Plan Savings and Investment by Program Component:

(a) Please provide a breakdown by program for the amounts attributed to "Residential Total (Incidental + Dedicated) Low Income & Equity Impacts".

Response IR-26:

(a) Please refer to Appendix A of E1's 2027–2031 DSM Resource Plan Application, page 35, Table 14: 2027–2031 DSM Preferred Plan Low-income and Equity Savings and Investment by Program Component (pdf page 123). Table 14 provides a breakdown by program component of the dedicated and incidental low-income and equity impacts that are included in the "Residential Total (Incidental + Dedicated) Low-Income & Equity Impacts" presented in Table 9 of the Evidence.

Request IR-27:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Table 9, pdf pg. 65: 2027-2031 DSM Preferred Plan Savings and Investment by Program Component - The table identifies three program components under Existing Residential, one under New Residential and one under Demand Response that are expected to provide lifetime benefits less than the 2027-2031 DSM Plan spending for the program component.

(a) Table 10, pdf pg. 66, outlines modifications to the programs. Have these programs been changed in order to maximize the lifetime benefits?

i) For the programs that have not been changed, please explain why it is acceptable for the lifetime benefits to be lower than the 5-year investment.

(b) How much more or less would E1 need to invest in these programs so that the value of the lifetime benefits is greater than the investment?

Response IR-27:

(a) The Program Administrator Cost (PAC) result represents the ratio of lifetime benefits to investment. EfficiencyOne (E1) considers PAC results for individual program components when designing or modifying programs. Accordingly, E1 strives to minimize program costs while maximizing lifetime benefits. While PAC results are a key consideration, E1 also evaluates additional factors when determining whether and how a program component should be delivered such as if it assists low-income and equity deserving customers.

A comparison between lifetime benefits and investment can be made if both values are a net present value (NPV). In Table 9 of E1's Evidence, the lifetime benefits are a NPV, while the investment is a sum of undiscounted costs. The PAC results in Table 9 represent the ratio of the NPV lifetime benefits to NPV investment and can be used for this purpose.

During Plan development, E1 adjusted incentive levels, modified measure uptake, explored different program delivery pathways and associated costs for various measures, and considered different ways to distribute participation across the Plan period based on NS Power's anticipated avoided costs. In some cases these modifications were made to improve cost-effectiveness and in others it was deemed necessary to better support certain customer segments. For example, as listed in E1's Evidence Table 10: 2027–2031 Enhancements, the Instant Savings program component plans to introduce space heating equipment, which is anticipated to offer a more cost-effective approach than the Home Energy Assessment program for customers who do not need or want a home energy evaluation. Another example is where Affordable Multi-family Housing incentives were increased, which reduces PAC results but is expected to improve project enrollment and conversion rates following the full allocation of provincial funding that had been offering top-up incentives to DSM participants until early 2025. These types of changes have resulted in fluctuating PAC scores at the measure, program component, and program levels over the duration of the Preferred Plan.

i) Table 1 of this IR response provides a summary of the program components that have a failing PAC (i.e., NPV Lifetime Benefits are less than the NPV of five-year investment) and a justification for the inclusion of these programs.

Table 1: Justification for Program Components with a failing PAC result.

Program Component	PAC Result *(NPV Lifetime Benefits / NPV Investment)*	Justification
Affordable Single-family Homes	0.8	These programs serve households on lower incomes and within equity deserving communities. Their inclusion in the Preferred Plan is important to ensuring energy efficiency is accessible regardless of income level and supports First Nations reconciliation efforts. Support for Affordable Single-family Homes and Mi'kmaw Home Energy Efficiency Project is consistent with prior Board approvals. The latter program is expected to conclude in early 2027 and will be replaced in the portfolio by Mi'kmaw New Home Construction.
Mi'kmaw Home Energy Efficiency Project	0.9	
Mi'kmaw New Home Construction	0.8	
Residential Demand Response	0.7	Residential Demand Response is being maintained at 2026 DSM Extension levels, with no new enrollments proposed during 2027–2031. E1 will focus on improving the existing Eco Shift device base by maintaining participation, improving connectivity and event performance, reducing opt-outs, and managing delivery costs. Continued operation preserves the value of prior investments while E1 works to improve program cost-effectiveness.

(b) E1 is unable to determine the additional or reduced investment required for lifetime benefits to exceed costs (i.e., for the program to pass the PAC test).

Investment and lifetime benefits are highly correlated, so as investment increases lifetime benefits will also increase. Similarly, if investment is decreased, lifetime benefits will also decrease. While economies of scale may improve cost-effectiveness at higher investment levels, it is also possible that the programs may not achieve cost-effectiveness at any scale.

Request IR-28:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

How did E1 arrive at the minimum 90% as the threshold for achievement of the performance targets?

(a) What are the industry standard thresholds for achieving a DSM performance target?

Response IR-28:

(a) EfficiencyOne (E1) is not aware of any standard mandated threshold across Canadian jurisdictions. Performance thresholds are a matter of regulatory design, set by reference to the policy objectives of the applicable DSM plan, the structure of the associated performance incentive mechanism, and the regulator's assessment of what constitutes meaningful accountability.

The 90% minimum achievement threshold is not a new construct in this proceeding. Previous Board-approved DSM Plans have incorporated the 90 percent floor for performance target achievement, and it has functioned as an effective and workable standard in practice. The threshold holds E1 to a meaningful standard of delivery while providing reasonable tolerance for factors outside its direct control, such as program uptake variability and macroeconomic conditions.

Request IR-29:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Table 11: Proposed 2027-2031 DSM Preferred Plan Performance Targets provides the expected energy savings. Please provide the number of customers by rate class that E1 forecasts participating in programs under each demand resource area to achieve these savings over the 2027-2031 period.

Response IR-29:

The number of customers (defined as number of NS Power customer accounts for the purposes of this IR response) by rate class that E1 forecasts participating in programs under each demand resource area over the 2027–2031 period is detailed in Table 1 below.

Table 1: 2027-2031 Participation by Rate Class for Resource Areas

Rate Class	Resource Area		
	Energy Efficiency	Demand Response	Solar-PV
Residential/Charitable (2,3,4)	130,768	9,266	200
Small General (10)	2,987	0	0
General (11)	4,658	112	0
Large General (12)	20	6	0
Small Industrial (21)	374	11	0
Medium Industrial (22)	132	44	0
Large Industrial (23, 25)	32	2	0
Municipal (24)	5	0	0
Unmetered (999)	Not quantified	0	0
Total	138,976	9,441	200

Request IR-30:

<u>Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)</u>

Regarding Section 8.1 "Mid-Course Adjustment Process" of the Application:

(a) Pdf pg. 69 states: "E1 has acknowledged the concerns raised by members of the DSMAG and engaged in discussions on these matters…"

i) Please provide a detailed summary of the feedback received from DSMAG members related to the mid-course adjustment process.

(b) Reference to Exhibit E-1, page 62 of 71 (pdf pg. 69), E1 states that the issues identified by members of the DSMAG were not created by actual mid-course adjustments but rather by actual rate class spending compared to the rate spending projected in the DSM plan. Please explain the difference and why E1 felt it was significant enough to provide this clarification.

(c) Pdf pg. 70 notes that E1 is proposing the following enhancements to its mid-course adjustment process: "Reducing the threshold from 25 percent to 20 percent for program changes both spending and savings that require explanations", and "Introducing a spending threshold of 15 percent for rate class spending changes that require explanations."

i) Please confirm whether these proposed enhancements have the support of all members of DSMAG.

Response IR-30:

(a)

i) Please refer to EfficiencyOne's (E1) response to NSEB IR-16.

(b) Mid-course adjustments (MCAs) provide E1 with flexibility to adjust annual program-level budgets and savings from those set out in the original Nova Scotia Energy Board (NSEB) approved DSM Plan, in order to respond to market conditions and program performance changes that were not known at the time of Plan development but become known during implementation of the DSM Plan. The rationale for these changes includes updated information from customers on project completion dates; challenges customers may be facing with supply chain issues such as product availability; industry capacity that affects contractor availability; and E1's third-party evaluation results. For example, when E1 develops a DSM Plan it estimates the number of participants per program. Since participation in E1's programs is driven by customer choice, actual participation may vary from the estimates in the DSM Plan and change over the implementation period. A range of factors may influence participation to increase or decrease such as availability of contractors to complete the work, product availability and the customer's disposal income at the time and their ability to invest in energy efficiency upgrades.

MCAs do not change approved overall savings or performance targets and are not a mechanism to revise NSEB approved Performance Targets. MCAs are intended to reflect adjustments within a given Plan year and to provide information to the NSEB and the Demand Side Management Advisory Group (DSMAG) of where E1 is projecting the program spending and savings for the year that may vary from the approved DSM Plan.

E1 believes the proposed revisions to the MCA process have addressed concerns raised during the 2026 DSM Extension process which were:

- E1 should spend DSM funding in the rate classes as it was approved by the NSEB; and
- E1 should manage spending at the rate class level in addition to at the program level, to mitigate the unanticipated cost impacts arising from variances in E1's planned DSM expenditures as compared to the actual DSM expenditures by customer class noting

that these variances could result in unexpected and significant impacts on customer classes where these costs have shifted by rate class.

As E1 had noted in the 2027–2031 DSM Plan Application, the above concerns are driven by actual rate-class spending outcomes relative to Plan projections, rather than the MCA mechanism itself; however, E1 recognizes that MCAs may influence the actual rate-class spending. The MCA process's primary objective is to provide an updated forecast for any given year that incorporates changes in the current landscape that may have influenced participation changes, cost changes and evaluation changes. This projection is intended to provide the NSEB and DSMAG members of E1's insights into what the year-end results may be, and also, explanations of why these changes have occurred.

E1 has proposed enhancements to the MCA process that explicitly incorporates rate-class spending considerations.

2026 DSM Extension Enhancements

In the 2026 DSM Extension matter, E1 agreed to provide the following enhancements:

- Improve the accuracy of estimates used for the rate class allocation of expenditures in the DSM Plan by using a minimum of three years of historical data which E1 did in the development of the 2027–2031 DSM Plan;
- Provide enhanced rate class reporting to address concerns, for example, year-end forecast and Plan period forecast to provide an outlook on projected rate class expenditures for the entire Plan period and the anticipated variances from the approved DSM Plan; and
- Monitor program spending against the DSM Plan and to clarify any variances within the approved DSM Plan budget.

In 2026, as part of efforts to enhance rate class spending reporting, E1 introduced a new rate class allocation methodology for quarterly and annual (where applicable) forecasts. In reporting forecasts by rate class, E1 discusses/explains variances comparing the MCA to forecast and to Plan.

E1 has also introduced Plan period tables by rate class each quarter, where past results and the most up-to-date forecast are reported to show where we expect to land for the Plan period and the DSM Plan spending by rate class as a percentage of total spending compared to the MCA and forecast.

2027–2031 DSM Plan Enhancements

E1 also proposed in the 2027–2031 DSM Plan Application further MCA enhancements including:

- Reducing the threshold from 25 percent to 20 percent for program changes for both spending and savings compared to the specific DSM Plan year that require explanations (Note: programs may consist of program components with program components rolling up into programs). Savings refer to the performance targets established by each DSM Resource as defined in the DSM Plan for the specific DSM Plan year; and
- Introducing a spending threshold of 15 percent or more for individual rate class spending changes for a specific DSM Plan year, where explanations are required. This provides clearer distinction from the program threshold mentioned above. In 2025, E1 provided variance explanations on spending by rate class of 25 percent or more by individual rate class and in 2026, E1 is providing variance explanations on spending by rate class of 15 percent or more by individual rate class to align with what is proposed in the 2027–2031 Plan. Although E1 intends to monitor and explain quarterly and annually, the overall objective of introducing a specific threshold of 15

percent or more by individual rate classes and providing explanations is to ensure actual cumulative spending at the end of the DSM Plan period as compared to the approved DSM Plan does not result in a substantial balance adjustment for any given rate class in future Demand Side Management Cost Recovery Rider (DCRR) applications.

To inform the MCA thresholds, E1 sought DSMAG member input. For the program changes, input received on what was appropriate was that E1 should lower the threshold from 25 percent to 20 percent, given that E1 has been delivering DSM programs since 2011 and has a more established baseline from which to assess variances. For rate class spending changes, the input received on what would be considered appropriate ranged from 10 percent to 15 percent or 30 percent. E1 selected a threshold of 15 percent as it represents a balance between providing meaningful early warning of material rate class spending variances and avoiding an undue reporting burden.

E1 is not considering expanding the MCA to also include sector changes in addition to program and rate class changes.

All reporting changes proposed by E1 for the MCA have been included in Appendix A - 2027–2031 DSM Plan, Section 13.4 Routine Reporting.

E1 has expanded both the annual budget and forecast review processes to incorporate both the 20 percent threshold on program spending and savings as well as the 15 percent threshold on rate class spending.

E1 is not proposing an additional regulatory process specific to the MCA. Historically E1 has filed the MCA with the NSEB in its Q1 DSM report. E1 understands that through this current process, the NSEB has broad regulatory powers to initiate any regulatory activities

or proceedings it deems appropriate to consider any aspect of the quarterly report including the MCA. E1 does not suggest in any way that the changes to the MCA process as proposed in the 2027–2031 Preferred DSM Plan impact the NSEB's authority nor is E1 suggesting a new regulatory process required to consider the MCA as filed in the Q1 report. E1 fully recognizes the NSEB's authority and ability to initiate a regulatory process as it deems appropriate for any reports, applications, and/or submissions as made by E1.

- Prior to filing the MCAs in E1's Q1 Report, the DSMAG will be provided the draft mid-course adjustments with explanations extending to a two-week comment period. E1 will respond to the comments prior to E1 including the mid-course adjustment in the Q1 Report;
- MCAs will be added as an agenda topic to the annual DSMAG session; and
- The MCA process will be included in the Standardized Filing Framework.

(c)

i) Consistent with E1's response to NSEB IR-16, the DSMAG Terms of Reference provide that submissions, comments, and positions taken by Members in DSMAG meetings or technical sessions are confidential and shall not be reproduced or made public, directly or indirectly, including in any future regulatory proceeding. Accordingly, E1 is not in a position to confirm or characterize the individual positions of DSMAG members with respect to the proposed MCA enhancements. E1 can confirm that the proposed enhancements were developed following DSMAG consultation and reflect E1's considered judgment as to appropriate adjustments to the MCA process for the 2027–2031 DSM Plan period.

Request IR-31:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 8.2 "Mid-Term Check-in" of the Application:

(a) With regards to the Mid-Term Check-in process described at lines 13 to 21 of pdf pg. 72: Does E1 intend to file a "Mid-term Check-in Report" with the Board following completion of the Mid-Term Check-in?

i) If not, why not?

Response IR-31:

(a) Please refer to EfficiencyOne's response to Synapse IR-72.

i) Please refer to part (a) of this response.

Request IR-32:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 9 "Alternate Scenario" of the Application:

(a) Pdf pg. 74 states: "The Alternate Scenario represents a total investment in energy efficiency, demand response and solar PV of $308.4 million over the 2027–2031 DSM Plan. The design approach maintained the levels of energy efficiency savings and investment for low-income and equity customers and solar-PV contained in the Preferred Plan and reduced demand response through the elimination of the Eco Shift program component."

i) Did the alternate scenario consider the removal of any DSM measures that did not meet the PAC test?

- **If not, why not?**
- **If so, please explain specifically why the alternate scenario does not include the removal of these measures.**

Response IR-32:

(a)

i) The Alternate Scenario did not consider the removal of DSM measures that did not meet the Program Administrator Cost (PAC) test for the following reasons: (1) many measures carry very low anticipated participation, investment, and savings, and their removal would have negligible impact on the portfolio's cost-effectiveness; (2) others were retained to preserve investment levels for low-income and equity seeking

customers, consistent with considerations applied across both the Preferred Plan and the Alternate Scenario.

Appendix A, Attachment 3 of E1's 2027-2031 DSM Plan Application, sets out specific justifications listed for all measures.

Request IR-33:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Regarding Section 10 "Conclusion" of the Application:

(a) Pdf pg. 75 notes: "The Preferred Plan delivers 435.4 GWh of incremental cumulative net energy savings, 85.0 MW of cumulative peak demand savings, 14.0 GWH of incremental cumulative net energy savings from dedicated low-income and equity programs, 29.3 MW of available capacity from demand response, and 1.7 GWh of energy reductions from customer-sited solar-PV generation".

i) Please explain the rationale for selecting 435.4 GWh of net energy savings as the target.

ii) When determining the target values for the Preferred Plan, please explain whether E1 prioritizes available budget or planned net energy savings and why.

Response IR-33:

(a)

i) As detailed in Attachment 1 to E1's response to NSEB IR-08, APEX's jurisdiction scan recommended an energy savings range of 0.8 percent to 1.0 percent of NS Power's load for the proposed 2027–2031 DSM Plan. The Preferred Plan target of 435.4 GWh of incremental cumulative net energy savings was an output of E1's modelling software, not a pre-determined input. At approximately 0.8 percent of NS Power's 2025 Load Forecast, this target sits at the lower range of APEX's recommended range, reflecting a conservative and achievable level of savings consistent with stakeholder

feedback and E1's affordability focused design approach reflecting current economic circumstances facing NS Power ratepayers.

ii) E1 prioritized short term affordability for the Preferred Plan by maintaining the annual investment of $63.75 million per year, the same level as the 2026 DSM Extension. Although this was the primary constraint for the proposed 2027–2031 DSM Preferred Plan, E1 also balanced other considerations when designing the portfolio. E1 has provided three examples below.

Deliverability – E1 must design programs that are achievable throughout the full five-year Plan period and that reflect realistic assumptions regarding market potential, industry capacity, and customer participation. Implementation to achieve the performance targets. This includes reviewing delivery approaches to streamline these where appropriate; being responsive to what we are hearing from our customers to improve the customer journey; introducing new programs and measures; ensuring that assumptions for participation are realistic and reasonable not just from potential but also considering the various measure incentives assumed; and taking into account industry capacity to support each program.

Cost Effectiveness – E1 must ensure the DSM Plan at the Plan (i.e., portfolio) level is cost effective, where benefits are greater or equal to the investment. In designing the portfolio, E1 must give careful thought to the cost effectiveness results of each program and the measures within each program since the DSM Plan results are an aggregate of these programs. E1 notes that cost effectiveness results of the portfolio of programs included in the proposed 2027–2031 DSM Preferred Plan is 2.4. This demonstrates that the annual investment of $63.75 million remains lower than

alternative supply side options that would be required to be generated to deliver the same level of energy savings and available capacity.

Program Mix – E1's portfolio must adhere to the Balanced Plan principles, which include, among other considerations, ensuring equitable access to programs for all ratepayers and rate classes. This principle requires E1 to address barriers to participation for low-income and equity-deserving communities. That commitment is reflected in the Preferred Plan's dedication of 14.0 GWh of incremental cumulative net energy savings to low-income and equity programs, ensuring that all Nova Scotians have a meaningful opportunity to reduce their electricity costs through participation in E1's programs.

Request IR-34:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Pdf pg. 87 defines Strategic Electrification as activities that shift end-uses from fossil fuels to electricity, while reducing both GHG emissions and electricity costs for customers.

(a) Please discuss how E1 considers "strategic" to play a role in these activities.

(b) Please describe end-uses that may be associated with these activities.

(c) Does E1 regard activities that shift end-uses from operating at peak as a means of reducing GHG emissions from fossil fuels based generation?

(d) Has E1 considered meeting the legislative requirements of Strategic Electrification through a two-part strategy, where one set of activities focuses on reducing GHG emissions and the other part focuses on reducing electricity costs for customers?

Response IR-34:

(a) EfficiencyOne (E1) understands strategic or beneficial electrification to refer to the deliberate shift from fossil-fuel based energy uses to electricity in a way that reduces overall energy costs, greenhouse gas (GHG) emissions, and enhances overall system efficiency and grid management – thus delivering broad public benefits. The term "strategic" reflects the deliberate and targeted nature of these activities: not all electrification initiatives qualify, but only those that simultaneously reduce GHG emissions

and electricity costs for customers, consistent with the requirements set out in section 79A of the Public Utilities Act (*PUA*).

(b) End-uses that may be associated with strategic electrification activities (i.e., shifting from fossil-fuel based energy to electricity) could include, but are not limited to: space heating (e.g., heat pumps replacing fossil fuel furnaces or boilers); water heating; other building electrification measures such as space cooling; transportation (i.e., shifting from fossil-fuel based energy to electricity); and custom or commercial/industrial projects. The specific end-uses pursued by E1 are informed by whether they can satisfy both the GHG reduction and electricity cost reduction requirements of section 79A of the *PUA*.

(c) E1 understands that activities that shift end-uses from operating at peak times could reduce GHG emissions from fossil fuel-based generation if the electricity emissions profile is lower during off-peak hours compared to on-peak hours. However, E1 does not currently have access to emissions data that differentiates between on-peak and off-peak periods. Accordingly, E1 cannot quantify the emissions reduction potential of demand-shifting activities on this basis. E1 will continue to monitor developments in emissions data availability and methodology that would allow for a more granular assessment in future DSM planning cycles.

(d) E1 understands that the strategic electrification resource as a whole must meet the requirements as set out in section 79A of the *PUA* and noted by the Nova Scotia Energy Board (NSEB) in their Decision[1] on E1's Application for Approval of a New Benefit-Cost Analysis (BCA) Test for Evaluating Demand Side Management Plans.

[1] M12282, NSEB Decision, E1 Application for approval of a New Benefit Cost Analysis Test for Evaluating Demand Side Management Plans, December 10, 2025.

E1 explored strategic electrification through the development of the 2027–2031 DSM Plan. E1 applied the modified Program Administrator Cost (PAC) test - which includes increased utility revenues, consistent with the approach recommended by the Industrial Group's consultant - when assessing strategic electrification initiatives. E1 understands the use of this modified-PAC to be consistent with the NSEB Decision on E1's Application for Approval of a New Benefit-Cost Analysis Test for Evaluating Demand Side Management Plans.[2] In addition to the modified-PAC assessment, E1 also evaluated the GHG emissions impact of assessed strategic electrification initiatives. E1 did not pursue a two-part strategy that separates GHG reduction activities from electricity cost reduction activities. Rather, E1 assessed scenarios as a whole against the conjunctive requirements of section 79A of the *PUA* - that is, any strategic electrification resource scenario must reduce both GHG emissions and electricity costs for customers. Ultimately, no strategic electrification scenario was included as a resource in the proposed 2027–2031 DSM Plan because none met both requirements as set out in section 79A of the *PUA*. E1's assessment was conducted within the existing legislative framework and E1 will continue to assess strategic electrification in future DSM planning cycles as market conditions, emissions data, and technology costs evolve.

[2] Ibid.

Request IR-35:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

As the system operator, IESO-NS is responsible for ensuring an adequate electricity supply is available to serve the provincial demand and energy requirements.

(a) Please explain what consultations were held with the IESO regarding the level of demand and energy reduction being incorporated into the DSM Plan.

(b) Did the IESO provide a target MW or MWh reduction for the DSM Plan?

(c) If no such discussions were held with the IESO, please explain why not.

Response IR-35:

(a) As a member of the Demand Side Management Advisory Group (DSMAG), the Nova Scotia Independent Energy System Operator (NSIESO) was engaged by EfficiencyOne (E1) in the development of the 2027–2031 DSM Plan. E1 has met one-on-one with the NSIESO outside of the DSMAG group sessions. As discussions through the DSMAG are confidential (this is explained in E1's response to NSEB IR-16,) E1 is understanding this IR to be asking about discussions outside of this forum. E1 confirms it did not receive a MW or MWh reduction target for 2027–2031 from the NSIESO.

(b) Please refer to part (a) of this IR response.

(c) Please refer to part (a) of this IR response.

Request IR-36:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

NS Power's IRP and Evergreen Update identified additional supply-side resources needed to serve projected demand and energy requirements.

(a) Did NS Power provide a target MW or MWh reduction for the DSM Plan?

i) If not, please explain why not.

ii) If yes, are the estimated demand and energy reductions in the DSM Plan consistent with reductions specified by NS Power?

(b) Please explain whether the DSM Plan is targeting any specific geographic problem area identified by NS Power. Was this issue discussed during development of the DSM Plan?

Response IR-36:

(a) As a member of the Demand Side Management Advisory Group (DSMAG), NS Power was engaged by EfficiencyOne (E1) in the development of the 2027–2031 DSM Plan. E1 has met one-on-one with NS Power outside of the DSMAG group sessions. As discussions through the DSMAG are confidential (this is explained in E1's response to NSEB IR-16), E1 understands this IR to be asking about discussions outside of this forum. E1 confirms it did not receive a MW or MWh reduction target for 2027–2031 from NS Power.

i) Please refer to part (a) of this IR response.

ii) Please refer to part (a) of this IR response.

(b) The proposed 2027–2031 DSM Plan is not targeting any specific geographic problem area and no such problem area was communicated to E1 by NS Power. Locational targeting was discussed with NS Power during the plan development at a high level. A formal data request was submitted to NS Power to provide an additional field in the AMI data that E1 receives from NS Power to include the Feeder ID and a list of the constrained areas. NS Power has confirmed that an enhancement is planned for its regular customer billing data transfer to E1 to include Feeder ID in order to tie specific customers to specific locations, enabling locational targeting. This data enhancement is expected to be received following NS Power's restoration of the AMI data transfer.

Request IR-37:

Evidence – Exhibit E-1, pp.1-71 (pdf pp. 8-78)

Absent any specific demand or energy reduction targets requested by NS Power or IESO-NS, please explain how E1 determined that the quantities and associated expenditures in its DSM Plan are the correct amounts that are necessary to be pursued at this time.

Response IR-37:

EfficiencyOne's (E1) proposed 2027–2031 DSM Preferred Plan, through a comprehensive suite of programs and service offerings is intended to:

- Reduce electricity costs for customers;
- Increase consumer awareness of cost-effective options for electricity consumption and/or consumption at peak periods;
- Create favourable market conditions for the increased adoption of energy efficient and system peak demand reduction equipment and upgrades; and
- Aid in meeting stringent climate change initiatives undertaken by Canada and the Province of Nova Scotia.

E1 considers the Integrated Resource Plan (IRP) as a directional input, providing a benchmark for savings within the DSM Plan. This approach is consistent with past Nova Scotia Energy Board (NSEB) direction and with the NSEB approved Standardized Filing Framework. Although an important consideration, the IRP is one of several inputs that E1 has considered in the weighed in developing the Preferred Plan including affordability, achievability, DSMAG engagement, and the Balanced Plan principles.

Affordability - E1's primary consideration in the development of the Preferred Plan was affordability. Please refer to E1's response to NSEB IR-03 for how E1 considered this in the Preferred Plan.

Achievability - Another consideration in the development of a DSM Plan is achievability. The Preferred Plan provides services that E1 has demonstrated success in the implementation of past DSM Plan, relies on E1's past experience successfully designing and delivering programs and has incorporated lessons learned from E1's past fifteen years implementing DSM Plan.

DSMAG Engagement - E1 engaged extensively with the Demand Side Management Advisory Group (DSMAG) throughout the development of the Preferred Plan. DSMAG members provided input on program design, target markets, and overall investment levels. Feedback received through this process was substantively considered and, in several cases, directly informed adjustments to program scope and expenditure allocations reflected in the Preferred Plan. E1 has committed to ongoing transparency and responsiveness in its engagement with the DSMAG throughout the 2027-2031 plan period.

Balanced Plan Principles - E1 has an obligation under the Standardized Framework to ensure the Preferred Plan was responsive to the Balanced Plan principles through multiple considerations, such as:

- The level of energy and capacity investments that can be avoided through the Preferred Plan;
- Cost of delivering programs;
- Diversity of program delivery to ensure customers are always considered; and
- Reducing barriers to participation by offering programs and services to all rate classes and market sectors.

Based on the comprehensive approach in the development of the Preferred Plan, E1 believes the investment level and the performance targets proposed are appropriate to be pursued in 2027–2031. This methodology — anchored in cost-effectiveness screening, affordability constraints, demonstrated achievability, and meaningful stakeholder engagement — provides the evidentiary basis for E1's conclusion that the proposed quantities and associated expenditures represent the appropriate level of DSM investment to be pursued in the 2027–2031 Plan period.

Request IR-38:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Please provide the unprotected spreadsheet with all cells intact for all Appendix A and Appendix B spreadsheet attachments.

Response IR-38:

As part of EfficiencyOne's (E1) 2027-2031 DSM Plan Application, filed on March 31, 2026, E1 included the following spreadsheets:

- **Appendix A, Attachment 1: 2027–2031 Modelling Assumptions**
  This attachment provides the modelling assumptions and their sources used in developing the proposed 2027–2031 DSM Plan, including avoided costs, the discount rate, and low-income and equity assumptions.
- **Appendix A, Attachment 3: 2027–2031 Energy Efficiency and Solar-PV Technical Tables**
  This attachment provides energy efficiency and solar-PV measure-level detail and is an output of the ProCESS™ model. Because calculations are performed within the ProCESS™ model rather than in Excel, E1 is unable to provide a version of Attachment 3 with formulas intact. To assist intervenors in understanding the underlying calculations, E1 has updated Appendix A, Attachment 3 – 2027-2031 Energy Efficiency and Solar-PV Technical Tables to include annotations describing the source and method of calculation for each measure-level technical table field. The updated Attachment 3 has been filed electronically as Attachment 1 to this IR response. Additionally, Attachment 2 to this IR response provides detailed assumption and methodology information for the measures comprising 80 percent of the energy savings in the proposed Preferred Plan.
- **Appendix A, Attachment 4: 2027–2031 Demand Response Technical Tables**

This attachment provides demand response output detail and is an output of the DRSim™ model. Because calculations are performed within the DRSim™ model rather than in Excel, E1 is unable to provide a version of Attachment 4 with formulas intact. To assist intervenors in understanding the underlying calculations, E1 has updated Appendix A, Attachment 4 – 2027–2031 Demand Response Technical Tables to include annotations describing the source and method of calculation for each measure-level technical table field. The updated Attachment 4 has been filed electronically as Attachment 3 to this IR response. Additionally, demand response input detail has been filed as Attachment 4 to this IR response.

- **Appendix B, Attachment 1: RBIA Summary Results – 2027–2031 DSM Plan and 2026 Historical**

  This attachment provides a summary of the rate and bill impacts results as taken from the E1 RBIA models filed as Appendix B, Attachments 9 and 10. It is meant to be assistive in the access and review of the RBIA results.

- **Appendix B, Attachments 7, 8, 9, and 10** are fully functional models as originally filed. Subsequently, on April 28, 2026, E1 re-filed Appendix B, Attachments 7 and 8 with macros removed in order to facilitate intervenors' ability to open those files. Attachments 9 and 10 remain as originally filed.

EfficiencyOne

2027-2031 DSM Plan Measure Reference Manual

Last Updated: May 13th, 2026

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1. INTRODUCTION

The purpose of this 2027-2031 DSM Plan Measure Reference Manual (Measure Reference Manual) is to document the critical inputs for the demand side management (DSM) measures included in EfficiencyOne's (E1) DSM plan.

E1's Measure Reference Manual is not intended as a prescriptive tool, but rather as a *descriptive* one. Rather than providing direction on how savings should be calculated, it presents, as transparently as possible, how savings *have* been calculated for each measure. This is intended to simplify the review of E1's input assumptions by internal and external stakeholders.

E1's DSM planning considers hundreds of measures. A comprehensive document providing detail on input assumptions for all measures considered as part of the planning process would be neither practical nor a cost-effective use of E1's limited resources. The Measure Reference Manual instead focuses on the measures with the most significant projected savings.

2. KEY SOURCES

Most measure inputs are derived from the results of EM&V conducted by E1's third-party evaluators. Section 2.1 provides a full citation for each such source, along with a concise internal reference (used when citing sources for specific measures), and a link to E1's internal SharePoint location for the source.

In some cases, other external sources are cited. Section 2.2 maps the internal reference for each of these to a full citation and to a publicly accessible link (where one is available).

2.1 EFFICIENCYONE SOURCES

Internal Reference	Full Citation
Custom Incentives Evaluation 2022	Econoler et al, *EfficiencyOne – Custom Incentives Program – Final Report – 2022 DSM Evaluation*, March 2023
Custom Incentives Evaluation 2024	Econoler et al, *EfficiencyOne – Custom Incentives Program – Final Report – 2024 DSM Evaluation*, March 2025
Custom Incentives Evaluation 2025	Econoler et al, *EfficiencyOne – Custom Incentives Program – Final Report – 2025 DSM Evaluation*, March 2026
2024-2025 DSM Measure Assessment	Econoler et al, *EfficiencyOne – 2024-2025 DSM Measure Assessment– Final Report – 2024 Evaluation Edition-Commercial*, March 2025
2024-2025 DSM Measure Assessment	Econoler et al, *EfficiencyOne – 2024-2025 DSM Measure Assessment– Final Report – 2024 Evaluation Edition-Residential*, March 2025
Incremental Cost Measure List 4	Apex Analytics, *Incremental Cost Measure List Draft – Version* 4, April 2025
Existing Residential Evaluation 2024	Econoler et al, *EfficiencyOne – Existing Residential Program – Final Report – 2024 DSM Evaluation*, March 2025

2.2 IMPORTANT AND USEFUL THIRD-PARTY SOURCES

Internal Reference	Full Citation	Link (External)
SEEAction 2017	State & Local Energy Efficiency Action Network, *SEE Action Guide for States: Guidance on Establishing and Maintaining Technical Reference Manuals for Energy Efficiency Measures,* Evaluation, Measurement, and Verification Working Group, June 2017	Link
EmPOWER 2023	Cadmus and Guidehouse, presented to: Baltimore Gas & Electric, Potomac Electric Power Company, Delmarva Power & Light, Potomac Edison, and Southern Maryland Electric Cooperative, *EmPOWER Maryland – Appendices: Cost-Effectiveness Data for 2022 EmPOWER Maryland Energy Efficiency Programs*, December 2023	Link

3. BUSINESS, NON-PROFIT, AND INSTITUTIONAL (BNI) ENERGY EFFICIENCY MEASURES

3.1 ANH_RETRO | CUSTOM – EQUITY DESERVING - RETROFITS

Custom provides large business, non-profit, and institutional (BNI) participants with technical assistance, financial incentives, and project financing to help reduce their electricity consumption and peak demand. Business Development Managers (BDM) also work with participants to assist them in moving their projects forward and identifying consultants.

Custom currently includes four different services: Retrofit, New Construction, Building Optimization, and Pay-for-Performance. This is a new service under consideration to be offered in the 2027-2031 DSM plan.

For DSM modelling purposes, E1 has assumed that this measure (service) will be offered in a manner that is relatively consistent with the current Retrofit service, with the distinction that this measure (service) will be dedicated to low-income and equity groups.

The Retrofit offering currently includes:

- Technical and financial support to help organizations conduct scoping and feasibility studies.
- Technical and financial support for the implementation of energy efficiency projects using a customized and flexible approach.
- Organizations with annual consumption of 350,000 kWh or higher are eligible provided projects have not yet started.

EfficiencyOne (E1) claims savings for certain Custom projects over multiple years since certain phases or measures can be fully operational before an entire project is completed.

Because of the heterogeneous mix of individual measures that are applied as part of this program, all measure characteristics are normalized on a “per GWh” basis (i.e., the unit basis for this measure is “per GWh of savings”).

3.1.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	ANH_RETRO
Measure ID (Incremental Cost)	BNI__CUS-IND_001
Common Measure Name	Equity Deserving - Retrofits
Sector	BNI
Program Name	Custom Incentives
Program Component	Custom
Replacement Type	RET
Unit Basis	Per GWh
DI Flag	0

3.1.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

This is a new measure. The measure characterization has been assumed to be consistent with CUS-IND_001. If there are any assumed differences in the measure characterization between this measure and CUS-IND_001, they will be flagged in the sections that follow. Refer to CUS_IND_001 for additional detail.

3.1.3 MEASURE LIFE

Value: 9.094

Source: Refer to CUS_IND_001

Details: The effective useful life for this measure is assumed to be consistent with CUS_IND_001.

3.1.4 NET TO GROSS

Value: 0.92

Source: Refer to CUS_IND_001

Details: The NTGR for this measure is assumed to be consistent with CUS_IND_001.

3.1.5 INCREMENTAL COST

Value: $382,537.50 (in $2025)

Unit: per GWh saved

Source: Refer to CUS_IND_001

Details: The incremental cost for this measure is assumed to be consistent with CUS_IND_001.

3.1.6 SAVINGS

3.1.6.1 Energy Savings (kWh)

Value: 1,000,000

Source: By construction.

Details: Due to the heterogenous nature of this bundled measure, the unit basis of “per GWh of savings” is used to determine the appropriate costs and incentives necessary to achieve 1 GWh of savings.

3.1.6.2 Coincident Peak Demand Savings (kW)

Value: 100.79 kW

Source: Refer to CUS_IND_001

Details: The peak demand savings for this measure are assumed to be consistent with CUS_IND_001.

3.2 CUS-NC_001 | CUSTOM – NEW CONSTRUCTION

Custom provides large business, non-profit, and institutional (BNI) participants with technical assistance, financial incentives, and project financing to help reduce their electricity consumption and peak demand. Business Development Managers (BDM) also work with participants to assist them in moving their projects forward and identifying consultants.

Custom currently includes four different services: Retrofit, New Construction, Building Optimization, and Pay-for-Performance.

The New Construction offering currently includes:

- Technical and financial support to achieve electrical energy savings in new buildings and for major renovations in existing buildings, excluding savings from lighting systems.
- Participation begins at the preliminary design stage to ensure the effective implementation of energy efficiency measures and achievement of maximum savings.
- Eligible facilities must be 15,000 sq ft or larger.
- Projects must achieve reductions in total building energy consumption of at least 25% and must save at least 100,000 kWh in electricity.

EfficiencyOne (E1) claims savings for certain Custom projects over multiple years since certain phases or measures can be fully operational before an entire project is completed.

Because of the heterogeneous mix of individual measures that are applied as part of this program, all measure characteristics are normalized on a “per GWh” basis (i.e., the unit basis for this measure is “per GWh of savings”).

3.2.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	CUS-NC_001
Measure ID (Incremental Cost)	BNI__CUS-NC_001
Common Measure Name	Custom - New Construction
Sector	BNI
Program Name	Custom Incentives
Program Component	Custom
Replacement Type	RET
Unit Basis	Per GWh
DI Flag	0

3.2.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is Table 19[1] from the 2024 Custom Incentives Evaluation. This table is reproduced below.

Table 19: Evaluated 2024 New Construction Gross Energy and Peak Demand Savings

	Partial Savings Claimed	Final Savings for Projects Fully Claimed in 2024	Total
Number of Projects	1	27	28
Energy Savings			
Tracked Gross Energy Savings – at the Meter (GWh)	6.273	13.340	19.613
Adjustment Ratio for Energy Savings	1.028	1.028	1.028
Gross Energy Savings – at the Meter (GWh)	**6.451**	**13.720**	**20.171**
Line Loss Factor	1.063	1.067	1.066
Gross Energy Savings – at the Generator (GWh)	**6.858**	**14.636**	**21.495**
Effective Useful Life (years)	20.0	18.5	19.0
Gross Lifetime Energy Savings – at the Generator (GWh)	**137.132**	**271.372**	**408.504**
Peak Demand Savings			
Tracked Gross Peak Demand Savings – at the Meter (MW)	0.716	3.003	3.719
Adjustment Ratio for Peak Demand Savings	1.003	1.003	1.003
Gross Peak Demand Savings – at the Meter (MW)	**0.718**	**3.012**	**3.730**
Line Loss Factor	1.0700	1.0742	1.0734
Gross Peak Demand Savings – at the Generator (MW)	**0.769**	**3.236**	**4.004**

[1] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 19: Evaluated 2024 New Construction Gross Energy and Peak Demand Savings, page 41 (PDF 813/1442)

3.2.3 MEASURE LIFE

Value: 19 Years

Source: Derived based on information in Table 19[2] from the Custom Incentives Evaluation 2024.

Details: To estimate the EUL, E1 divided Total gross lifetime energy savings at the generator by Total annual gross energy savings at the meter, as show in the table below.

Input	Description	Total
A	Gross Energy Savings - at the Generator (GWh)	21.495
B	Gross Lifetime Energy Savings - at the Generator (GWh)	408.504
C = B / A	Measure Life	19.00461

3.2.4 NET TO GROSS

Value: 0.82

Source: Drawn directly from Table 25[3] of the 2025 Custom Incentives Evaluation.

Table 25: Evaluated 2025 New Construction NTGR

	Projects Fully Claimed in 2025
Free-ridership Level	18%
NTGR	**0.82**

3.2.5 INCREMENTAL COST

Value: $382,537.50 (in $2025)

Unit: per GWh saved

Source: Refer to CUS_IND_001

Details: The incremental cost for this measure is assumed to be consistent with CUS_IND_001.

[2] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 19: Evaluated 2024 New Construction Gross Energy and Peak Demand Savings, page 41 (PDF 813/1442)

[3] 2025 Custom Incentive Evaluation, Net Savings, Table 25: Evaluated 2024 New Construction NTGR, page 31

3.2.6 SAVINGS

3.2.6.1 Energy Savings (kWh)

Value: 1,000,000

Source: By construction.

Details: Due to the heterogenous nature of this bundled measure, the unit basis of "per GWh of savings" is used to determine the appropriate costs and incentives necessary to achieve 1 GWh of savings.

3.2.6.2 Coincident Peak Demand Savings (kW)

Value: 184.93

Source: Derived based on information in Table 19[4] from the 2024 Custom Incentives Evaluation.

Table 19: Evaluated 2024 New Construction Gross Energy and Peak Demand Savings

	Partial Savings Claimed	Final Savings for Projects Fully Claimed in 2024	Total
Number of Projects	1	27	28
Energy Savings			
Tracked Gross Energy Savings – at the Meter (GWh)	6.273	13.340	19.613
Adjustment Ratio for Energy Savings	1.028	1.028	1.028
Gross Energy Savings – at the Meter (GWh)	**6.451**	**13.720**	**20.171**
Line Loss Factor	1.063	1.067	1.066
Gross Energy Savings – at the Generator (GWh)	**6.858**	**14.636**	**21.495**
Effective Useful Life (years)	20.0	18.5	19.0
Gross Lifetime Energy Savings – at the Generator (GWh)	**137.132**	**271.372**	**408.504**
Peak Demand Savings			
Tracked Gross Peak Demand Savings – at the Meter (MW)	0.716	3.003	3.719
Adjustment Ratio for Peak Demand Savings	1.003	1.003	1.003
Gross Peak Demand Savings – at the Meter (MW)	**0.718**	**3.012**	**3.730**
Line Loss Factor	1.0700	1.0742	1.0734
Gross Peak Demand Savings – at the Generator (MW)	**0.769**	**3.236**	**4.004**

Details: This value was calculated by dividing the 2024 Gross Peak Demand Savings - at the Meter by the 2024 Gross Energy Savings - at the Meter.

Input	Description	Total
A	Total Gross Energy Savings - at the Meter	20.17
B	Total Gross Peak Demand Savings - at the Meter	3.73
C = B / A	kW savings per 1,000,000 kWh	184.93

[4] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 19: Evaluated 2024 New Construction Gross Energy and Peak Demand Savings, page 41 (PDF 813/1442)

3.3 CUS-IND_001 | CUSTOM – INDUSTRIAL RETROFIT

The Custom provides large business, non-profit, and institutional (BNI) participants with technical assistance, financial incentives, and project financing to help reduce their electricity consumption and peak demand. Business Development Managers (BDM) also work with participants to assist them in moving their projects forward and identifying consultants.

Custom currently includes four different services: Retrofit, New Construction, Building Optimization, and Pay-for-Performance.

The Retrofit offering currently includes:

- Technical and financial support to help organizations conduct scoping and feasibility studies.
- Technical and financial support for the implementation of energy efficiency projects using a customized and flexible approach.
- Organizations with annual consumption of 350,000 kWh or higher are eligible provided projects have not yet started.[5]

EfficiencyOne (E1) claims savings for certain Custom projects over multiple years since certain phases or measures can be fully operational before an entire project is completed.

Because of the heterogeneous mix of individual measures that are applied as part of this program, all measure characteristics are normalized on a “per GWh” basis (i.e., the unit basis for this measure is “per GWh of savings”).

[5] The Retrofit service also includes compressed air leak audits and solar PV projects for which a semi-prescriptive approach is used to establish evaluated savings.

3.3.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	CUS-IND_001
Measure ID (Incremental Cost)	BNI__CUS-IND_001
Common Measure Name	Custom - Industrial Retrofit
Sector	BNI
Program Name	Custom Incentives
Program Component	Custom
Replacement Type	RET
Unit Basis	Per GWh
DI Flag	0

3.3.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary sources of values for measure input development are Table 11[6] and Table 16[7] from the 2024 Custom Incentives Evaluation, as well as historical project-level program results. These tables are reproduced below.

[6] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 11: Evaluated 2024 Retrofit Gross Energy and Peak Demand Savings, page 18 (PDF 790/1442)

[7] 2024 Custom Incentive Evaluation, Evaluated Net Savings, Table 16: Evaluated 2024 Retrofit Net Energy and Peak Demand Savings, page 22 (PDF 793/1442)

Table 11: Evaluated 2024 Retrofit Gross Energy and Peak Demand Savings

	Partial Savings Claimed	Final Savings Claimed for Single-Year Projects	Final Savings Claimed for Multiyear Projects	Total
Number of Projects	13	61	14	88
Energy Savings				
Tracked Gross Energy Savings – at the Meter (GWh)	13.168	9.525	2.106	24.799
Adjustment Ratio for Energy Savings*	0.990	1.012	1.011	1.001
Gross Energy Savings Without True-up Adjustment (GWh)	13.041	9.644	2.129	24.814
True-up Adjustment for Gross Energy Savings (GWh)	-	-	0.211	0.211
Gross Energy Savings – at the Meter (GWh)	**13.041**	**9.644**	**2.339**	**25.025**
Line Loss Factor**	1.0489	1.0597	1.0499	1.0532
Gross Energy Savings – at the Generator (GWh)	**13.679**	**10.220**	**2.456**	**26.355**
Effective Useful Life (years)***	5.9	10.5	12.1	8.2
Gross Lifetime Energy Savings – at the Generator (GWh)	**80.305**	**106.974**	**29.712**	**216.991**
Peak Demand Savings				
Tracked Gross Peak Demand Savings – at the Meter (MW)	1.408	0.786	0.368	2.561
Adjustment Ratio for Peak Demand Savings*	1.006	1.003	1.003	1.005
Gross Peak Demand Savings Without True-up Adjustment (MW)	1.416	0.789	0.369	2.573
True-up Adjustment for Gross Peak Demand Savings (MW)	-	-	-0.010	-0.010
Gross Peak Demand Savings – at the Meter (MW)	**1.416**	**0.789**	**0.359**	**2.564**
Line Loss Factor**	1.0469	1.0533	1.0514	1.0495
Gross Peak Demand Savings – at the Generator (MW)	**1.482**	**0.831**	**0.377**	**2.691**

* The adjustment ratios listed in this table are the averages obtained by dividing gross savings without true-up adjustments by tracked savings. They differ from the values presented in Table 9 above because of the different adjustment ratios applied to each project category.

** The line loss factors are average values obtained by dividing gross savings at the generator by gross savings at the meter. Each retrofit project received its own specific line loss factor based on participant rate codes.

*** These EULs are average EUL values obtained by dividing gross lifetime energy savings by gross energy savings. Each retrofit project received its own specific EUL to obtain lifetime savings.

1

Table 16: Evaluated 2024 Retrofit Net Energy and Peak Demand Savings

	Partial Savings Claimed	Final Savings Claimed for Single-year Projects	Final Savings Claimed for Multiyear Projects	Total
Energy Savings				
Gross Energy Savings – at the Meter (GWh)	13.041	9.644	2.339	25.025
NTGR*	0.84	0.81	0.85	0.83
Net Energy Savings Without True-up Adjustment (GWh)	10.981	7.815	1.982	20.777
True-up Adjustment for Net Energy Savings (GWh)	-	-	0.762	0.762
Net Energy Savings – at the Meter (GWh)	**10.981**	**7.815**	**2.743**	**21.539**
Line Loss Factor**	1.049	1.059	1.052	1.053
Net Energy Savings – at the Generator (GWh)	**11.518**	**8.274**	**2.885**	**22.677**
Effective Useful Life***	5.9	10.4	12.9	8.4
Net Lifetime Energy Savings – at the Generator (GWh)	**67.785**	**85.942**	**37.209**	**190.936**
Peak Demand Savings				
Gross Peak Demand Savings – at the Meter (MW)	1.416	0.789	0.359	2.564
NTGR*	0.84	0.85	0.85	0.84
Net Peak Demand Savings Without True-up Adjustment (MW)	1.192	0.669	0.304	2.166
True-up Adjustment for Net Peak Demand Savings (MW)	-	-	0.015	0.015
Net Peak Demand Savings – at the Meter (MW)	**1.192**	**0.669**	**0.320**	**2.181**
Line Loss Factor**	1.047	1.053	1.051	1.049
Net Peak Demand Savings – at the Generator (MW)	**1.248**	**0.705**	**0.336**	**2.289**

*The NTGRs listed in this table match the rounded averages obtained by dividing net savings by gross savings. They differ from the values presented in Subsection 3.3.3 above because of true-up adjustments and the different NTGRs applied to each project category.

**The line loss factors are average values obtained by dividing gross savings at the generator by gross savings at the meter. Each retrofit project received its own specific line loss factor depending on participant rate codes.

***These are average EUL values obtained by dividing gross lifetime energy savings by gross energy savings. Each retrofit project received its own specific EUL to obtain lifetime savings.

3.3.3 MEASURE LIFE

Value: 9.094

Source: Derived based on information in Table 11[8] from the 2024 Custom Incentives Evaluation.

Details: To estimate the EUL, E1 calculated the average EUL of the three categories of Retrofit program measures (Partial Savings Claimed, Final Savings Claimed for Single-Year Projects, and Final Savings

[8] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 11: Evaluated 2024 Retrofit Gross Energy and Peak Demand Savings, page 18 (PDF 790/1442)

Claimed for Multiyear Projects), weighted on the basis of each category's lifetime gross savings at the meter, as shown in the table below.

Input	Description	Partial Savings Claimed	Final Savings Claimed for Single-Year Projects	Final Savings Claimed for Multiyear Projects
A	EUL (Effective Useful Life)	5.9	10.4	12.9
B	Gross Energy Savings - at the Meter (GWh)	13.041	9.644	2.339
C = A * B	Gross Lifetime Saving (Gross Energy Savings – at the Meter (GWh) multiplied by the EUL)	76.9	100.3	30.2
D = C/SUM(C)	Share of Gross Lifetime Savings	37%	48%	15%
2024 Weighted Average EUL		**9.09Years**		

3.3.4 NET TO GROSS

Value: 0.92

Source: Derived based on information in Table 15[9] from the 2025 Custom Incentives Evaluation.

Details: Table 15[10] was used to calculate the sum of gross lifetime savings (at the meter) for all three categories of Retrofit project (Partial Savings Claimed, Final Savings Claimed for Single-Year Projects, and Final Savings Claimed for Multiyear Projects). The NTG ratio of projects deemed as Regular Retrofits was used as the NTG for this measure.

3.3.5 INCREMENTAL COST

Value: $382,537.50 (in $2025)

Unit: per GWh of energy savings

Source: Incremental Costs were developed by Apex Analytics in 2024.

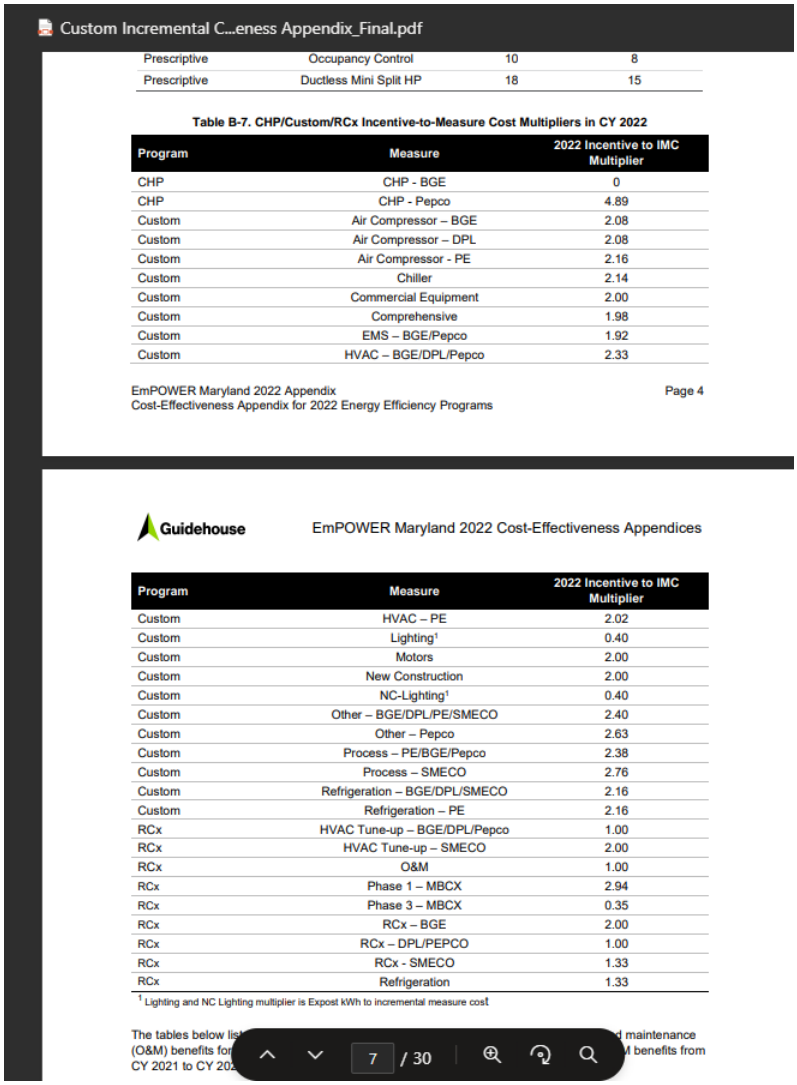
Details: The incremental cost of this measure is assumed to be 2.5x the average incentive across the period from 2024 through 2031. The incentive for this measure varies, with an average of 15 cents per kWh. This

[9] 2025 Custom Incentive Evaluation, Evaluated Gross Savings, Table 15: Evaluated 2025 Retrofit Gross Energy and Peak Demand Savings, page 18 (PDF 790/1442)

[10] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 11: Evaluated 2024 Retrofit Gross Energy and Peak Demand Savings, page 18 (PDF 790/1442)

multiplier is used because, at this time, insufficient program tracking data is readily available to develop a more robust estimate of measure costs.

The 2.5x multiplier was recommended by E1's evaluation contractor (Apex Analytics) for this measure as being an average used in other jurisdictions. Apex cited Table B-7 of the EmPOWER 2023 report as the source for this incentive-to-measure cost ratio.[11]


Custom Incremental C...eness Appendix_Final.pdf

Prescriptive	Occupancy Control	10	8
Prescriptive	Ductless Mini Split HP	18	15

Table B-7. CHP/Custom/RCx Incentive-to-Measure Cost Multipliers in CY 2022

Program	Measure	2022 Incentive to IMC Multiplier
CHP	CHP - BGE	0
CHP	CHP - Pepco	4.89
Custom	Air Compressor – BGE	2.08
Custom	Air Compressor – DPL	2.08
Custom	Air Compressor - PE	2.16
Custom	Chiller	2.14
Custom	Commercial Equipment	2.00
Custom	Comprehensive	1.98
Custom	EMS – BGE/Pepco	1.92
Custom	HVAC – BGE/DPL/Pepco	2.33

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Guidehouse EmPOWER Maryland 2022 Cost-Effectiveness Appendices

Program	Measure	2022 Incentive to IMC Multiplier
Custom	HVAC – PE	2.02
Custom	Lighting[1]	0.40
Custom	Motors	2.00
Custom	New Construction	2.00
Custom	NC-Lighting[1]	0.40
Custom	Other – BGE/DPL/PE/SMECO	2.40
Custom	Other – Pepco	2.63
Custom	Process – PE/BGE/Pepco	2.38
Custom	Process – SMECO	2.76
Custom	Refrigeration – BGE/DPL/SMECO	2.16
Custom	Refrigeration – PE	2.16
RCx	HVAC Tune-up – BGE/DPL/Pepco	1.00
RCx	HVAC Tune-up – SMECO	2.00
RCx	O&M	1.00
RCx	Phase 1 – MBCX	2.94
RCx	Phase 3 – MBCX	0.35
RCx	RCx – BGE	2.00
RCx	RCx – DPL/PEPCO	1.00
RCx	RCx - SMECO	1.33
RCx	Refrigeration	1.33

[1] Lighting and NC Lighting multiplier is Expost kWh to incremental measure cost

The tables below lis... maintenance (O&M) benefits for... benefits from CY 2021 to CY 202...

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[11] EmPOWER Maryland, Appendices: Cost-Effectiveness Data for 2022 EmPOWER Maryland Energy Efficiency Programs, Table B-7 December 5, 2023.

E1's DSM planning contractor (Guidehouse) has recommended that in subsequent evaluation and/or planning cycles incremental cost data for this measure should be collected as part of program tracking data, and this place-holder value updated with a program-specific Nova Scotia estimate.

3.3.6 SAVINGS

3.3.6.1 Energy Savings (kWh)

Value: 1,000,000

Source: By construction.

Details: Due to the heterogenous nature of this bundled measure, the unit basis of "per GWh of savings" is used to determine the appropriate costs and incentives necessary to achieve 1 GWh of savings.

3.3.6.2 Coincident Peak Demand Savings (kW)

Value: 100.79

Source: Derived based on 2024 Custom Incentives Evaluation project level data.

Details: This value was calculated by dividing the evaluation adjusted project-level 2024 Gross Peak Demand Savings - at the Meter by the evaluation adjusted project-level 2024 Gross Energy Savings - at the Meter for Custom Industrial Retrofit.

Input	Description	Adjusted Gross Energy Savings – at the Meter (GWh)	Adjusted Gross Demand Savings – at the Meter (MW)
A	Final Single Year	6.982	0.658
B	Final Multiyear	2.026	0.241
C	Partial Single Year & Multiyear	11.952	1.213
D = A+B+C	Total	20.960	2.113
E	kW/GWh	100.79	

3.4 CUS-RET_001 | CUSTOM – COMMERCIAL RETROFIT

The measure description provided below is the same as that provided for CUS-IND_001. What distinguishes these measures is the sector to which they are applied.

The Custom provides large business, non-profit, and institutional (BNI) participants with technical assistance, financial incentives, and project financing to help reduce their electricity consumption and peak demand. Business Development Managers (BDM) also work with participants to assist them in moving their projects forward and identifying consultants.

Custom currently includes four different services: Retrofit, New Construction, Building Optimization, and Pay-for-Performance.

The Retrofit offering currently includes:

- Technical and financial support to help organizations conduct scoping and feasibility studies.
- Technical and financial support for the implementation of energy efficiency projects using a customized and flexible approach.
- Organizations with annual consumption of 350,000 kWh or higher are eligible provided projects have not yet started.[12]

EfficiencyOne (E1) claims savings for certain Custom projects over multiple years since certain phases or measures can be fully operational before an entire project is completed.

Because of the heterogeneous mix of individual measures that are applied as part of this program, all measure characteristics are normalized on a “per GWh” basis (i.e., the unit basis for this measure is “per GWh of savings”).

[12] The Retrofit service also includes compressed air leak audits and solar PV projects for which a semi-prescriptive approach is used to establish evaluated savings.

3.4.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	CUS-RET_001
Measure ID (Incremental Cost)	BNI_CUS-RET_001
Common Measure Name	Custom - Commercial Retrofit
Sector	BNI
Program Name	Custom Incentives
Program Component	Custom
Replacement Type	RET
Unit Basis	Per GWh
DI Flag	0 (Not DI)

3.4.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The measure characterization has been assumed to be consistent with CUS-IND_001. If there are any assumed differences in the measure characterization between this measure and CUS-IND_001, they will be flagged in the sections that follow. Refer to CUS_IND_001 for additional detail.

3.4.3 MEASURE LIFE

Value: 9.094

Source: Refer to CUS_IND_001

Details: The effective useful life for this measure is assumed to be consistent with CUS_IND_001.

3.4.4 NET TO GROSS

Value: 0.92

Source: Refer to CUS_IND_001

Details: The NTGR for this measure is assumed to be consistent with CUS_IND_001.

3.4.5 INCREMENTAL COST

Value: $382,537.50 (in $2025)

Unit: per GWh saved

Source: Refer to CUS_IND_001

Details: The incremental cost for this measure is assumed to be consistent with CUS_IND_001.

3.4.6 SAVINGS

3.4.6.1 Energy Savings (kWh)

Value: 1,000,000

Source: By construction.

Details: Due to the heterogenous nature of this bundled measure, the unit basis of "per GWh of savings" is used to determine the appropriate costs and incentives necessary to achieve 1 GWh of savings.

3.4.6.2 Coincident Peak Demand Savings (kW)

Value: 102.44

Source: Derived based on information in Table 11[13] from the 2024 Custom Incentives Evaluation.

Details: This value was calculated by dividing the 2024 Gross Peak Demand Savings - at the Meter by the 2024 Gross Energy Savings - at the Meter.

Input	Description	Total
A	Total Gross Energy Savings - at the Meter	25.02
B	Total Gross Peak Demand Savings - at the Meter	2.56
C = B / A	kW savings per 1,000,000 kWh	102.44

[13] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 11: Evaluated 2024 Retrofit Gross Energy and Peak Demand Savings, page 18 (PDF 790/1442)

3.5 CUS-P4P_001 | CUSTOM - PAY FOR PERFORMANCE

Custom provides large business, non-profit, and institutional (BNI) participants with technical assistance, financial incentives, and project financing to help reduce their electricity consumption and peak demand. Business Development Managers (BDM) also work with participants to assist them in moving their projects forward and identifying consultants.

Custom currently includes four different services: Retrofit, New Construction, Building Optimization, and Pay-for-Performance.

The Pay-for-Performance (P4P) offering currently includes:

- Financial support for reductions in electricity consumption achieved through a variety of capital and behavioural energy efficiency upgrades.
- Incentives are based on verified facility energy performance.
- Organizations with annual consumption of 1,000,000 kWh or higher are eligible if projects generate reductions in electricity consumption of at least 10%.

EfficiencyOne (E1) claims savings for certain Custom projects over multiple years since certain phases or measures can be fully operational before an entire project is completed.

Because of the heterogeneous mix of individual measures that are applied as part of this program, all measure characteristics are normalized on a “per GWh” basis (i.e., the unit basis for this measure is “per GWh of savings”).

3.5.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	CUS-P4P_001
Measure ID (Incremental Cost)	BNI__CUS-P4P_001
Common Measure Name	Custom - Pay for Performance
Sector	BNI
Program Name	Custom Incentives
Program Component	Custom
Replacement Type	RET
Unit Basis	Per GWh
DI Flag	0

3.5.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is Table 21[14] from the 2022 Custom Incentives Evaluation. This table is reproduced below.

Table 21: Evaluated 2022 P4P Gross Energy and Peak Demand Savings

	Final Savings for Projects Fully Claimed in 2022	Final Savings for Multiyear Projects	Total
Number of Projects	**22**	**58**	**80**
Energy Savings			
Tracked Gross Energy Savings – at the Meter (GWh)	1.031	1.245	2.276
Adjustment Ratio for Energy Savings	1.024	1.024	-
Gross Energy Savings Without True-up Adjustment (GWh)	1.055	1.275	2.330
True-up Adjustment for Gross Energy Savings (GWh)	-	0.387	0.387
Gross Energy Savings – at the Meter (GWh)	**1.055**	**1.662**	**2.717**
Line Loss Factor	1.063	1.063	-
Gross Energy Savings – at the Generator (GWh)	**1.122**	**1.767**	**2.889**
Effective Useful Life (years)	11.2	11.2	-
Gross Lifetime Energy Savings – at the Generator (GWh)	12.565	19.787	**32.352**
Peak Demand Savings			
Tracked Gross Peak Demand Savings – at the Meter (MW)	0.065	0.531	0.595
Adjustment Ratio for Peak Demand Savings	0.937	0.937	-
Gross Peak Demand Savings Without True-up Adjustment (MW)	0.060	0.497	0.558
True-up Adjustment for Gross Peak Demand Savings (MW)	-	0.000	0.000
Gross Peak Demand Savings – at the Meter (MW)	**0.060**	**0.497**	**0.558**
Line Loss Factor	1.070	1.070	-
Gross Peak Demand Savings – at the Generator (MW)	**0.065**	**0.532**	**0.597**

3.5.3 MEASURE LIFE

Value: 11.20 Years

Source: Derived based on information in Table 21[15] from the 2022 Custom Incentives Evaluation.

Details: To estimate the EUL, E1 divided Total gross lifetime energy savings at the generator by Total annual gross energy savings at the meter, as shown in the table below.

[14] 2022 Custom Incentive Evaluation, Evaluated Gross Savings, Table 21: Evaluated 2022 P4P Gross Energy and Peak Demand Savings, page 32 (PDF 663/1087)

[15] 2022 Custom Incentive Evaluation, Evaluated Gross Savings, Table 21: Evaluated 2022 P4P Gross Energy and Peak Demand Savings, page 32 (PDF 663/1087)

Input	Description	Total
A	Gross Energy Savings - at the Generator (GWh)	2.89
B	Gross Lifetime Energy Savings - at the Generator (GWh)	32.35
C = B / A	Measure Life	11.20

3.5.4 NET TO GROSS

Value: 0.92

Source: Drawn directly from Table 2025[16] from the 2025 Custom Incentives Evaluation.

Table 25: Evaluated 2025 P4P NTGR

	Projects Fully Claimed in 2025
Free-ridership Level	8%
NTGR	**0.92**

3.5.5 INCREMENTAL COST

Value: $255,025.00 (in $2025)

Unit: per GWh saved

Source: Refer to CUS_IND_001

Details: The incremental cost for this measure is assumed to be consistent with CUS_IND_001.

3.5.6 SAVINGS

3.5.6.1 Energy Savings (kWh)

Value: 1,000,000

Source: By construction.

[16] 2025 Custom Incentive Evaluation, Net Savings, Table 20: Evaluated 2022 P4P NTGRs, page 25 (PDF 664/1087)

Details: Due to the heterogenous nature of this bundled measure, the unit basis of "per GWh of savings" is used to determine the appropriate costs and incentives necessary to achieve 1 GWh of savings.

3.5.6.2 Coincident Peak Demand Savings (kW)

Value: 206.65

Source: Derived based on information in Table 21[17] from the 2022 Custom Incentives Evaluation.

Details: This value was calculated using the approach set out in the table below:

Input	Description	Total
A	Annual Gross Savings at the Generator (GWh)	1.00
B	Hours per Year	8760.00
C = B * (1000*1000)/A	Average kW Demand Impact	114.16
D	Annual Gross Savings at the Generator (GWh)	2.89
E	Annual Gross Peak Demand Savings MW	0.60
F = (E/1000)/D	GW per GWh of savings	0.00
G = F*1000*1000	kW per 1,000,000 kWh of savings	206.65

[17] 2022 Custom Incentive Evaluation, Evaluated Gross Savings, Table 21: Evaluated 2022 P4P Gross Energy and Peak Demand Savings, page 32 (PDF 663/1087)

3.6 CUS-BO__001 | CUSTOM – BUILDING OPTIMIZATION

Custom provides large business, non-profit, and institutional (BNI) participants with technical assistance, financial incentives, and project financing to help reduce their electricity consumption and peak demand. Business Development Managers (BDM) also work with participants to assist them in moving their projects forward and identifying consultants.

Custom currently includes four different services: Retrofit, New Construction, Building Optimization, and Pay-for-Performance.

The Building Optimization offering currently includes:

- Technical and financial support to help organizations conduct an investigation study with the objective of improving building operational efficiency.
- Technical and financial support for the implementation of no cost or low-cost energy efficiency measures (e.g. operating schedule changes) identified through a recommissioning process.
- Eligible facilities must not have been commissioned in the previous two years, must have a building automation system and annually consume 350,000 kWh or more.

EfficiencyOne (E1) claims savings for certain Custom projects over multiple years since certain phases or measures can be fully operational before an entire project is completed.

Because of the heterogeneous mix of individual measures that are applied as part of this program, all measure characteristics are normalized on a “per GWh” basis (i.e., the unit basis for this measure is “per GWh of savings”).

3.6.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	CUS-BO__001
Measure ID (Incremental Cost)	BNI__CUS-BO__001
Common Measure Name	Custom - Building Optimization
Sector	BNI
Program Name	Custom Incentives
Program Component	Custom
Replacement Type	RET
Unit Basis	Per GWh
DI Flag	0

3.6.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is Table 24[18] from the 2024 Custom Incentives Evaluation. This table is reproduced below.

Table 24: Evaluated 2024 Building Optimization Gross Energy and Peak Demand Savings

	Partial Savings Claimed	Final Savings Claimed for Single-Year Projects	Total
Number of Projects	2	2	4
Energy Savings			
Tracked Gross Energy Savings – at the Meter (GWh)	1.540	0.297	1.838
Adjustment Ratio for Energy Savings*	1.000	1.068	1.011
Gross Energy Savings – at the Meter (GWh)	**1.540**	**0.318**	**1.858**
Line Loss Factor**	1.0631	1.0631	1.0631
Gross Energy Savings – at the Generator (GWh)	**1.638**	**0.338**	**1.975**
Effective Useful Life (years)***	1.5	3.0	1.8
Gross Lifetime Energy Savings – at the Generator (GWh)	**2.456**	**1.013**	**3.469**
Peak Demand Savings			
Tracked Gross Peak Demand Savings – at the Meter (MW)	-	0.095	0.095
Adjustment Ratio for Peak Demand Savings*	-	0.899	0.899
Gross Peak Demand Savings – at the Meter (MW)	-	**0.086**	**0.086**
Line Loss Factor**	-	1.0700	1.0700
Gross Peak Demand Savings – at the Generator (MW)	-	**0.092**	**0.092**

*The adjustment ratios listed in this table are the averages obtained by dividing gross energy savings without true-up adjustments by tracked gross energy savings.

**The line loss factors are average values obtained by dividing gross savings at the generator by gross savings at the meter. Each Retrofit project received its own specific line loss factor depending on participant rate codes.

***These are average EUL values obtained by dividing gross lifetime energy savings by gross energy savings. Each retrofit project received its own specific EUL to obtain lifetime savings.

[18] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 24: Evaluated 2024 Building Optimization Gross Energy and Peak Demand Savings, page 47 (PDF 819/1442)

3.6.3 MEASURE LIFE

Value: 1.76 Years

Source: Derived based on information in Table 24[19] from the 2024 Custom Incentives Evaluation.

Details: To estimate the EUL, E1 divided Total gross lifetime energy savings at the generator by Total annual gross energy savings at the meter, as shown in the table below.

Input	Description	Total
A	Gross Energy Savings - at the Generator (GWh)	1.98
B	Gross Lifetime Energy Savings - at the Generator (GWh)	3.47
C = B / A	Measure Life	1.76

3.6.4 NET TO GROSS

Value: 0.91

Source: Drawn directly from Table 25[20] from the 2024 Custom Incentives Evaluation.

Table 26: Evaluated 2024 Building Optimization NTGR

	Value for Savings Claimed in 2024 *
Free-Ridership Level	9% (±7.2%)
Participant Spillover Level	0%
NTGR	**0.91**
*Free-ridership and spillover levels were not measured in 2024, results from the 2021 Custom evaluation were applied.	

3.6.5 INCREMENTAL COST

Value: $140,263.75 (in $2025)

Unit: per GWh saved

Source: Refer to CUS_IND_001

Details: The incremental cost for this measure is assumed to be consistent with CUS_IND_001.

[19] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 24: Evaluated 2024 Building Optimization Gross Energy and Peak Demand Savings, page 47 (PDF 819/1442)

[20] 2024 Custom Incentive Evaluation, Net Savings, Table 26: Evaluated 2024 Building Optimization NTGR, page 48 (PDF 820/1442)

3.6.6 SAVINGS

3.6.6.1 Energy Savings (kWh)

Value: 1,000,000

Source: By construction.

Details: Due to the heterogenous nature of this bundled measure, the unit basis of "per GWh of savings" is used to determine the appropriate costs and incentives necessary to achieve 1 GWh of savings.

3.6.6.2 Coincident Peak Demand Savings (kW)

Value: 46.07

Source: Derived based on information in Table 24[21] from the 2024 Custom Incentives Evaluation.

Details: This value was calculated by dividing the Gross Peak Demand Savings - at the Meter by the Gross Energy Savings - at the Meter.

Input	Description	Total
A	Total Gross Energy Savings - at the Meter	1.86
B	Total Gross Peak Demand Savings - at the Meter	0.09
C = B / A	kW savings per 1,000,000 kWh	46.07

[21] 2024 Custom Incentive Evaluation, Evaluated Gross Savings, Table 24: Evaluated 2024 Building Optimization Gross Energy and Peak Demand Savings, page 47 (PDF 819/1442)

3.7 SEM_001 | CUSTOM – STRATEGIC ENERGY MANAGEMNET

Custom provides large business, non-profit, and institutional (BNI) participants with technical assistance, financial incentives, and project financing to help reduce their electricity consumption and peak demand.

SEM provides industrial and institutional participants with funding and support to implement energy management practices within their organizations. It also provides participants with energy management information system (EMIS) implementation support.

SEM helps participants achieve continuous energy savings by offering a structured approach to identifying, prioritizing, and completing energy-saving actions through the implementation of energy management policies and processes. To be eligible, participants must possess the necessary resources to implement energy efficient improvements, demonstrate commitment to energy management, and identify committed personnel to work in collaboration with E1 throughout the duration of projects. Activities are conducted through a third-party Service Provider that delivers the program component. Participants commit to participating for 12 months, although E1 offers additional years to participants who want to continue operating the energy management system. SEM participants can also obtain funding for an EMIS, which is an additional tool that assists participants in using energy consumption data from metered systems to inform decisions about their processes. This funding may be used to conduct an EMIS audit, develop and implement an EMIS plan that involves the configuration of metering and monitoring equipment, as well as procure training and organizational support.

SEM provides participants with energy Kaizens and mapping, treasure hunts, energy management assessments, as well as performance monitoring and reporting tools. SEM also provides employee training and organizational support for the implementation of energy management engagement activities that use energy performance information to prompt actions aimed at achieving behavioural change and operation and maintenance related energy-saving measures. Ultimately, SEM helps develop an energy management plan focused on changing business practices to enhance long-term energy performance.

Because of the heterogeneous mix of individual measures that are applied as part of this program, all measure characteristics are normalized on a “per GWh” basis (i.e., the unit basis for this measure is “per GWh of savings”).

3.7.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	SEM_001
Measure ID (Incremental Cost)	BNI__SEM_001
Common Measure Name	Custom - Strategic Energy Management
Sector	BNI
Program Name	Custom Incentives
Program Component	SEM
Replacement Type	RET
Unit Basis	Per GWh
DI Flag	0

3.7.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is Table 32[22] from the 2024 Custom Incentives Evaluation. This table is reproduced below.

Table 32: Evaluated 2024 SEM Gross Electrical Energy and Peak Demand Savings

	New Projects	Continuing Projects	Total
Number of Projects	**1**	**6**	**7**
Energy Savings			
Tracked Gross Energy Savings (GWh)	1.186	3.083	4.269
Adjustment Ratio for Energy Savings	1.000	0.999	1.000
Gross Energy Savings – at the Meter (GWh)	**1.186**	**3.081**	**4.267**
Line Loss Factor	1.0547	1.0473	1.0493
Gross Energy Savings – at the Generator (GWh)	**1.251**	**3.227**	**4.478**
Equivalent Effective Useful Life (years)	3.0	2.4	2.6
Gross Lifetime Energy Savings – at the Generator (GWh)	**3.753**	**7.829**	**11.581**
Peak Demand Savings			
Tracked Gross Peak Demand Savings (MW)	0.135	0.377	0.512
Adjustment Ratio for Peak Demand Savings	1.000	1.003	1.002
Gross Peak Demand Savings – at the Meter (MW)	**0.135**	**0.378**	**0.513**
Line Loss Factor	1.0558	1.0457	1.0484
Gross Peak Demand Savings – at the Generator (MW)	**0.143**	**0.395**	**0.538**

3.7.3 MEASURE LIFE

Value: 5.81 Years

[22] 2024 Custom Incentive Evaluation, Evaluated Gross Savings Table 32: Evaluated 2024 SEM Gross Electrical Energy and Peak Demand Savings, page 67 (PDF 839/1442)

Source: 2023 Custom Incentives Program, Table 36: Evaluated 2023 SEM Gross Energy and Peak Demand Savings, page 71 (PDF 86/94)

Details: The EUL of this measure is the weighed average measure life of new projects and continuing projects. This was used as to not over-weight shorter measure lives of continuing projects.

3.7.4 NET TO GROSS

Value: 1.0

Source: Drawn directly from the 2024 Custom Incentives Evaluation, page 68.[23] The evaluator assumes that the NTGR for SEM is 1.0.

3.7.5 INCREMENTAL COST

Value: $136,673.24 (in $2025)

Unit: per GWh saved

Source: Derived based on average unit cost of 2022, 2023, and 2024 evaluated SEM results

Details: The incremental cost is "Performance Based Incentives" and the "Service Provider Costs" paid by E1 for this service. This was based on tracked program data for the program.

Input	Description	2022	2023	2024
A	Evaluated Gross at meter Energy Savings (GWh)	3.177	3.381	4.478
B	Total Incentives	$442,679	$498,179	$552,292
C = B /A	Total Unit Cost without Recoveries ($/GWh)	139,338.64	147,346.57	123,334.50
D = average C	Average unit cost $	136,673.24		

3.7.6 SAVINGS

3.7.6.1 Energy Savings (kWh)

Value: 1,000,000

Source: By construction.

[23] 2024 Custom Incentive Evaluation, Net Savings, page 68 (PDF 840/1442)

Details: Due to the heterogenous nature of this bundled measure, the unit basis of "per GWh of savings" is used to determine the appropriate costs and incentives necessary to achieve 1 GWh of savings.

3.7.6.2 Coincident Peak Demand Savings (kW)

Value: 120.2

Source: Derived based on information in Table 32[24] from the 2024 Custom Incentives Evaluation.

Details: This value was calculated by dividing the Gross Peak Demand Savings - at the Meter by the Gross Energy Savings - at the Meter.

Input	Description	Total
A	Total Gross Energy Savings - at the Meter	4.27
B	Total Gross Peak Demand Savings - at the Meter	0.51
C = B / A	kW savings per 1,000,000 kWh	120.26

[24] 2024 Custom Incentive Evaluation, Evaluated Gross Savings Table 32: Evaluated 2024 SEM Gross Electrical Energy and Peak Demand Savings, page 67 (PDF 839/1442)

3.8 BER-AR__LGT_INHORT_001__0 | AR - INDOOR - HORTICULTURAL LIGHTING

BER provides financial incentives in the form of prescriptive rebates or financing to business, non-profit, and institutional (BNI) participants to foster reductions in electricity consumption and peak demand. All businesses, non-profits, and institutions in Nova Scotia are eligible. Figure 1 presents an overview of the program component.

Measures offered through BER must meet specific criteria including minimum efficiency/efficacy values as well as industry standards such as ENERGY STAR® certified performance levels or those established by the DesignLights Consortium (DLC) and the National Electrical Manufacturers Association.

Rebates offered through BER are delivered through two services, the Application Rebates (AR) service and the Instant Rebates (IR) service. Instant Rebates reaches a greater number of participants and offers quick and convenient access to BER but is limited in tracking participant details. Conversely, Application Rebates allows for better project-level control since more participant details are provided to E1. All BER technologies are available through Application Rebates, while only certain lighting and pumping technologies are eligible through Instant Rebates.

Instant Rebates is delivered through a network of participating distributors in the Province of Nova Scotia. These distributors play a key role in promoting Instant Rebates to end users. Distributors also provide customer services for measures that are only eligible through Application Rebates by sharing their expertise and assisting with completing applications.

3.8.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	BER-AR__LGT_INHORT_001__0
Measure ID (Incremental Cost)	BNI__LGT_INHORT_001__0
Common Measure Name	AR - Indoor - Horticultural Lighting
Sector	BNI
Program Name	BNI Efficient Product Rebates
Program Component	Business Energy Rebates
Replacement Type	RET
Unit Basis	Per unit
DI Flag	0

3.8.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is the Horticultural Lighting Measure[25] from the 2024-2025 DSM Commercial Measure Assessment. The measure summary table from this section is reproduced below.

Table 165: Horticultural Lighting Measure Summary

Parameter	BER-AR		Reference
	Retrofit	New Construction	
Measure Description and Identification			
Measure Description	Horticultural lighting rebated after installation		-
Baseline	Existing lighting	Metal halide HID fixtures	
General Parameters			
Installation Rate	100%		See details below under Installation Rates
Effective Useful Life [years]	8.3		See Subsection 6.1
Electrical Savings Parameters			
Unitary Energy Savings [kWh/year]	Calculation based on specification data for each rebated unit		See details below under Electrical Unitary Energy Savings
Peak Coincidence Factor	Actual		-
Unitary Peak Demand Savings [W]	Calculation based on specification data for each rebated unit		See details below under Unitary Peak Demand Savings
Interactive Effects Factor for Energy Savings	Actual		-
Interactive Effects Factor for Peak Demand Savings	Actual		

3.8.3 MEASURE LIFE

Value: 2.77 Years

Source: Econoler – interim EUL Methodology/Draft 2025 Measure Assessment

[25] 2024 DSM Evaluation Reports, 2024-2025 DSM Measure Assessment, BNI, Lighting Measures, Horticultural Lighting, page 161 (PDF 1243/1442)

Details: This was based on Econoler's updated lighting baseline EUL adjustment methodology and updated 2025 Measure Assessment draft methodologies designed to best capture future savings potential. This value is subject to change in the finalized 2025 Measure Assessment.

3.8.4 NET TO GROSS

Value: 0.94

Source: Drawn directly from the 2025 BER Evaluation Report v2.0 (pg. 34)

3.8.5 INCREMENTAL COST

Value: $62.60 (In $2025)

Unit: per GWh saved

Source: Incremental Costs were developed by Apex Analytics in 2024.

Details: Baseline and efficient costs were sourced from web scraping and labour hours were sourced from the PA ACT129 Incremental Cost database.

3.8.6 SAVINGS

3.8.6.1 Energy Savings (kWh)

Value: 2,058.18

Source: Value is an average or recent tracked evaluated savings for this measure.

Details: In practice, energy savings calculations are based on specification data for each rebated unit. Electrical unitary energy savings are calculated using the following equation and the corresponding parameters set out in the Horticultural Lighting Measure[26] in the 2024-2025 Measure Assessment.

$$Unitary\ Energy\ Savings\ \left[\frac{kWh}{yr}\right] = \frac{(W_b[W] \times Qty_b[-] - W_b[W] \times Qty_b[-]) \times HOU\left[\frac{h}{yr}\right] \times IE}{1{,}000}$$

[26] 2024 DSM Evaluation Reports, 2024-2025 DSM Measure Assessment, BNI, Lighting Measures, Horticultural Lighting, page 161 (PDF 1243/1442)

Table 166: Electrical Unitary Energy Savings Values for Horticultural Lighting

Parameter	Symbol	BER-AR		Reference
		Retrofit	New Construction	
Baseline Wattage [W]	W_b	Actual	1,000	Retrofit: Use information in TS New Construction: 2020 Iowa TRM[213] Remillard & Collins 2017[214]
Baseline Quantity [-]	Qty_b	Actual	Same as Qty_e	Retrofit: Use information in TS New Construction: Assumption
New Wattage [W]	W_e	Actual		Use information in TS
New Quantity [-]	Qty_e	Actual		Use information in TS
Hours of Operation [hours/year]	HOU	Actual		Use information in TS
Energy Savings Interactive Effects Factor [-]	IE	Actual		Use information in TS
Conversion Factor [W/kW]	-	1,000		Convention
Unitary Energy Savings [kWh/year]	$Unitary\ Energy\ Savings$	Calculation based on project data		Calculation

3.8.6.2 Coincident Peak Demand Savings (kW)

Value: 0.512

Source: Value is the average or recently evaluated tracked savings for this measure.

Details: In practice, unitary peak demand savings are calculated using the following equation and the corresponding parameters set out in the Horticultural Lighting Measure[27] in the 2024-2025 Measure Assessment.

$$Unitary\ Peak\ Demand\ Savings\ [kW] = \frac{(W_b[W] \times Qty_b[-] - W_e[W] \times Qty_e[-]) \times PCF \times IE_{PD}}{1{,}000}$$

Table 167: Unitary Peak Demand Savings Values for Horticultural Lighting

Parameter	Symbol	BER-AR		Reference
		Retrofit	New Construction	
Peak Coincidence Factor [-]	PCF	Actual		Use information in TS
Energy Savings Interactive Effects Factor [-]	IE_{PD}	Actual		Use information in TS
Conversion Factor [W/kW]	-	1,000		Convention
Unitary Energy Savings [kW]	$Unitary\ Peak\ Demand\ Savings$	Calculation based on project data		Calculation

[27] 2024 DSM Evaluation Reports, 2024-2025 DSM Measure Assessment, BNI, Lighting Measures, Horticultural Lighting, page 161 (PDF 1243/1442)

3.9 BER-AR__HVAC_MSHP_MURB_001__0_A | AR - SMALL DUCTLESS MINI-SPLIT HEAT PUMP - MURB (NO BASELINE COOLING)

BER provides financial incentives in the form of prescriptive rebates or financing to business, non-profit, and institutional (BNI) participants to foster reductions in electricity consumption and peak demand. All businesses, non-profits, and institutions in Nova Scotia are eligible. Figure 1 presents an overview of the program component.

Measures offered through BER must meet specific criteria including minimum efficiency/efficacy values as well as industry standards such as ENERGY STAR® certified performance levels or those established by the DesignLights Consortium (DLC) and the National Electrical Manufacturers Association.

Rebates offered through BER are delivered through two services, the Application Rebates (AR) service and the Instant Rebates (IR) service. Instant Rebates reaches a greater number of participants and offers quick and convenient access to BER but is limited in tracking participant details. Conversely, Application Rebates allows for better project-level control since more participant details are provided to E1. All BER technologies are available through Application Rebates, while only certain lighting and pumping technologies are eligible through Instant Rebates.

Instant Rebates is delivered through a network of participating distributors in the Province of Nova Scotia. These distributors play a key role in promoting Instant Rebates to end users. Distributors also provide customer services for measures that are only eligible through Application Rebates by sharing their expertise and assisting with completing applications.

3.9.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	BER-AR__HVAC_MSHP_MURB_001__0_A
Measure ID (Incremental Cost)	BNI__HVAC_MSHP_MURB_001__0_A
Common Measure Name	AR - Small Ductless Mini-Split Heat Pump - MURB (no baseline cooling)
Sector	BNI
Program Name	BNI Efficient Product Rebates
Program Component	Business Energy Rebates
Replacement Type	RET
Unit Basis	Per unit
DI Flag	0

3.9.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is recent BER-AR program tracking data for this measure.

3.9.3 MEASURE LIFE

Value: 18 Years

Source: Assumed consistent with the EUL value for Residential ductless mini-split heat pumps from the 2024-2025 Residential Measure Assessment, Table 135.[28]

3.9.4 NET TO GROSS

Value: 0.83

Source: Drawn directly from the 2025 BER Evaluation Report v2.0 (pg. 34)

3.9.5 INCREMENTAL COST

Value: $4,324.22 (In $2025)

Unit: per heat pump

Source: Incremental Costs were developed by Apex Analytics in 2024.

Details: Efficient material and labour costs were sourced via contractor interviews and average efficient measure costs from program tracking information.

[28] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

3.9.6 SAVINGS

3.9.6.1 Energy Savings (kWh)

Value: 4,826.22

Source: Value is the average or recent savings tracked for this measure.

3.9.6.2 Coincident Peak Demand Savings (kW)

Value: 1.648

Source: Value is the average or recent savings tracked for this measure.

4. RESIDENTIAL ENERGY EFFICIENCY MEASURES

4.1 AMFH__HVAC_HP_001__0 | AIR-SOURCE HEAT PUMP - DUCTED AND NON-DUCTED (NOT MODELLED)

AMFH provides affordable housing owners and non-profit organizations, such as rehabilitation or transition houses, with incentives for building-wide energy retrofit projects with the intent of reducing electrical and non-electrical energy consumption in Nova Scotia. Unless they follow a prescriptive path to install specific measures, AMH projects must undergo a complimentary energy audit at the beginning of the participation process to identify eligible energy efficiency measures such as water and space heating systems and building envelope measures.

Since 2021, AMH savings have been generated through two project paths, the comprehensive path and prescriptive path.

Comprehensive path projects serve to implement measures that are modelled in HOT2000, RETScreen, or CANQuest. Energy savings from comprehensive projects are calculated by comparing the energy models of a base case and a proposed case. Calculations are performed with project-specific parameters.

Prescriptive path projects are not modelled because their energy savings are calculated using E1's internal energy savings calculation tools, which is a tool presenting the savings calculation methodologies, assumptions, and calculation parameters for measures implemented under AMH.

4.1.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	AMFH__HVAC_HP_001__0
Measure ID (Incremental Cost)	AMFH__HVAC_HP_001__0
Common Measure Name	Air-Source Heat Pump - ducted and non-ducted (not modelled)
Sector	Residential
Program Name	Existing Residential
Program Component	Affordable Multi-Family Housing
Replacement Type	RET
Unit Basis	Per project
DI Flag	0

4.1.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below.

4.1.3 MEASURE LIFE

Value: 18 Years

Source: The EUL value for this prescriptive measure was drawn from the 2024 DSM Program Evaluation Reports.[29]

Table 10: 2024 AMH Equivalent EUL Values for Comprehensive Projects

Measure Category	Share of Savings [%]	Evaluated Equivalent EUL [years]	Reference
Heating Systems	63.9%	18	GDS, 2007 – Heat Pumps
Building Envelopes	22.2%	30	California Public Utilities Commission, 2023
Fenestration	10.6%	20	DEER, 2014 – Windows
Ventilation	1.8%	10	GDS, 2007 – Programmable Thermostats
Lighting	1.5%	5.7	Lifetime of 50,000 hours based on model specifications; assumption that lamps are in common zones and turned on 24/7
Weighted Average EUL	**100%**	**20.5**	**Calculation**

This value is consistent with the EUL value used for this measure in HEA and Green Heat, as set out in Table 135[30] of the 2024 DSM Measure Assessment.

4.1.4 NET TO GROSS

Value: 1.0

Source: As set out in the 2024 DSM Program Evaluation Reports, [31] free-ridership and spillover effects are nil since participants are non-profits or low-income housing owners with limited budgets for building improvements. Therefore, a NTGR of 1.00 was applied.

4.1.5 DIRECT INSTALL COST

Value: $25,817.67 (in 2025, escalated in out years)

Unit Basis: per project

[29] 2024 Existing Residential Evaluation Report, Affordable Multi-Family Homes, Effective Useful Life, Table 10: 2024 AMH Equivalent EUL Values for Comprehensive Projects, page 30 (PDF page 1212/1442).

[30] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

[31] 2024 Existing Residential Evaluation, Affordable Multi-Family Homes, Net Savings, Realization Rate, Table 13: Comparison of 2024 AMH Tracked and Evaluated Savings at the Generator, page 33 (PDF 237/1442)

Source: Per E1 program tracking.

Details: This value is the average direct installation cost per measure from recent tracked program data (January 2023-April 2024), escalated to 2025.

4.1.6 SAVINGS

Energy Savings (kWh)

Value: 12,144.6382

Source: Average savings value calculated using recent tracked savings for this measure.

Details: In practice, savings for prescriptive path projects are calculated using savings calculation methodologies, assumptions, and calculation parameters for measures implemented under AMH.

Coincident Peak Demand Savings (kW)

Value: 7.32799

Source: Average savings value calculated using recent tracked savings for this measure.

Details: In practice, savings for prescriptive path projects are calculated using savings calculation methodologies, assumptions, and calculation parameters for measures implemented under AMH.

4.2 EPI__DHW_SHEAD_EPI_003__0 | LOW FLOW SHOWERHEAD - 1 GPM IMPROVEMENT

EPI provides participants with free-of-charge direct installations of energy efficient products. EPI has played a pivotal role in transforming the residential lighting market by making energy-efficient products more affordable. Importantly, as LEDs have become the baseline, EPI is set to phase out lighting measures and focus on electrician-installed energy-efficient products. Electrician-installed measures will be key in delivering Residential Demand Response activities. E1 contracts service providers to deliver EPI across the province. EPI is available to both homeowners and renters and encourages participants to also consider other E1 residential program components.

Electrician-installed measures were introduced to EPI in 2024, except smart thermostats for electric baseboards and DHW heater load controllers that were introduced with a limited scope in 2023 as well as smart thermostats for MSHP that were introduced in 2022.

EPI funding comes from two sources: (1) Electricity ratepayer funding is used for upgrades that reduce electricity consumption; and (2) funding from the Government of Nova Scotia using funds from the Green Fund for upgrades that reduce the use of other fuels. This report presents the evaluation results for the electricity ratepayer portion of EPI only.

4.2.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	EPI__DHW_SHEAD_EPI_003__0
Measure ID (Incremental Cost)	N/A
Common Measure Name	Low Flow Showerhead - 1 GPM improvement
Sector	Residential
Program Name	Existing Residential
Program Component	Efficient Products Installation
Replacement Type	RET
Unit Basis	Per unit
DI Flag	1

4.2.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is the Low-flow Showerhead Measure[32] from the 2024-2025 DSM Residential Measure Assessment. The measure summary table from this section is reproduced below.

Table 35: Low-flow Showerhead Measure Summary

Parameter	EPI						Reference
Measure Description and Identification							
Measure	Low-flow showerheads for electric DHW heating with direct installation						-
Baseline	Standard showerhead with a flow rate of at least 2 gpm						-
Measure Subcategory	Single-family homes			Apartments			-
	Flow rate reduction of 0.5 gpm	Flow rate reduction of 0.75 gpm	Flow rate reduction of 1 gpm	Flow rate reduction of 0.5 gpm	Flow rate reduction of 0.75 gpm	Flow rate reduction of 1 gpm	
General Parameters							
Installation Rate	95%						See details below under Installation Rates
Effective Useful Life [years]	10						See Subsection 3.2
Electrical Savings Parameters							
Unitary Energy Savings [kWh/year]	197	296	395	225	338	450	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0.162						See Subsection 2.2.2
Unitary Peak Demand Savings [W]	31.9	48.0	64.0	36.5	54.8	72.9	Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%						See Subsection 2.2.1
Interactive Effects Factor for Peak Demand Savings	0%						See Subsection 2.2.1

4.2.3 MEASURE LIFE

Value: 10 Years

Source: This value was drawn from Table 135[33] of the 2024 DSM Measure Assessment.

Low-flow Showerheads	EPI, Instant Savings	10	DEER, 2014 (Value for low-flow showerheads)

4.2.4 NET TO GROSS

Value: 0.99

[32] 2024 DSM Evaluation Reports, 2024-2025 DSM Measure Assessment, Residential, Water Heating Measures, Low-flow Showerheads, page 40 (PDF 1122/1442)

[33] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

Source: This value was drawn from Table 37 of the 2024 Existing Residential Evaluation.[34]

Table 37: 2024 EPI Net-to-gross Ratios by Product Category

Products	Participant Type	NTGR	Proportion of Product Category Gross Savings by Participant Type	Overall NTGR Values
LED Lamps and Lighting Related Products	Non-low-income Participants	0.92	32%	0.97
	Low-income Participants	1.00	68%	
Smart and Advanced Learning Thermostats	Non-low-income Participants	0.99	49%	1.00
	Low-income Participants	1.00	51%	
DHW Products	Non-low-income Participants	0.97	35%	0.99
	Low-income Participants	1.00	65%	
Air Sealing Products	Non-low-income Participants	0.96	41%	0.98
	Low-income Participants	1.00	59%	
Smart Power Controllers	Non-low-income Participants	1.05	38%	1.02
	Low-income Participants	1.00	62%	
Humidity Sensors	Non-low-income Participants	1.08	51%	1.04
	Low-income Participants	1.00	49%	

4.2.5 DIRECT INSTALL COST

Value: $55.56 (in $2025)

Unit Basis: per unit

Source: Per E1 program tracking.

Details: This value is the average direct installation cost per measure from recent tracked program data, escalated for 2025.

4.2.6 SAVINGS

4.2.6.1 Energy Savings (kWh)

Value: 377.22

Source: Average savings value calculated using recent tracked savings for this measure.

Details: In practice, energy savings calculations are based on specification data for each rebated unit. Electrical unitary energy savings are calculated using the following equation and the corresponding parameters set out in the Low-flow Showerhead Measure[35] in the 2024-2025 Measure Assessment.

[34] 2024 Existing Residential Evaluation, Table 37: 2024 EPI Net-to-gross Ratios by Product Category, page 111 (PDF 315/1442)

[35] 2024 DSM Evaluation Reports, 2024-2025 DSM Measure Assessment, Residential, Water Heating Measures, Low-flow Showerheads, page 40 (PDF 1122/1442)

1

$$Energy\ Savings\ \left[\frac{kWh}{year}\right] = DHW\ Reduction\left[\frac{gal}{day}\right] \times \frac{1}{\eta} \times Cp_{H20}\left[\frac{Btu}{lb \cdot °F}\right] \times \rho_{H20}\left[\frac{lb}{ft^3}\right] \times \Delta T_{H20}[°F] \times n_{days}\left[\frac{days}{year}\right] \times UC1\left[\frac{kWh}{Btu}\right] \times UC2\left[\frac{ft^3}{gal}\right] \times \%DWH_{elec}$$

$$DHW\ Reduction\left[\frac{gal}{day}\right] = (q_{base} - q_{low})[gpm] \times \frac{n_{people}[person]}{n_{showerheads}} \times \%_{DHW} \times t_{shower}[\frac{min}{shower}] \times n_{shower}[\frac{shower}{day \cdot person}]$$

2

3

Table 36: Electrical Unitary Energy Savings Values for Low-flow Showerheads

Parameter	Symbol	EPI		Reference
		Single-family Homes	Apartments	
Baseline Flow Rate [gpm]	q_{base}	Variable (2.0 gpm, 2.25 gpm, or 2.5 gpm)	Variable (2.0 gpm, 2.25 gpm, or 2.5 gpm)	Measure specific - use information in TS
Low-flow Rate [gpm]	q_{low}	1.5		2021 EPI Program Manual
Number of People per Household [person]	n_{people}	2.5	1.9	2020 EPI November tracking sheet
Average Number of Showers per Day per Person [shower/day/person]	n_{shower}	0.67		Mayer and Oreo[59]
Number of Showerheads per Household [showers]	$n_{showerheads}$	1.50	1	Single-family homes: 2024 EPI Evaluation (on-site visits) Apartments: Assumption
Average Shower Time per Person [min/shower]	t_{shower}	7.8		DeOreo et al.[60]
Percentage of Hot Water Used in Showers	$\%_{DHW}$	63%		DeOreo et al.[61]
Number of Days per Year [days/year]	n_{days}	365		Convention
Specific Heat of Water [Btu/lb°F]	Cp_{H2O}	1		Convention
Density of Water [lb/ft^3]	ρ_{H2O}	62.43		Convention
Temperature Rise in Electrical Water Heater [°F]	ΔT_{H2O}	79		2011 OPA[62]
Electrical Water Heater Efficiency	η	98%		Pennsylvania Public Utility Commission TRM[63]
Unit Conversion #1 [kWh/Btu]	UC1	0.000293083		Convention

4

5

4.2.6.2 Coincident Peak Demand Savings (kW)

Value: 0.061

Source: Average savings value calculated using recent tracked savings for this measure.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.162 - RES-Water Heat, Navigant 2016-2018 DSM Plan).

4.3 EPI__HVAC_HUMS_EPI_001__0 | HUMIDITY SENSOR

EPI provides participants with free-of-charge direct installations of energy efficient products. EPI has played a pivotal role in transforming the residential lighting market by making energy-efficient products more affordable. Importantly, as LEDs have become the baseline, EPI is set to phase out lighting measures and focus on electrician-installed energy-efficient products. Electrician-installed measures will be key in delivering Residential Demand Response activities. E1 contracts service providers to deliver EPI across the province. EPI is available to both homeowners and renters and encourages participants to also consider other E1 residential program components.

Electrician-installed measures were introduced to EPI in 2024, except smart thermostats for electric baseboards and DHW heater load controllers that were introduced with a limited scope in 2023 as well as smart thermostats for MSHP that were introduced in 2022.

EPI funding comes from two sources: (1) Electricity ratepayer funding is used for upgrades that reduce electricity consumption; and (2) funding from the Government of Nova Scotia using funds from the Green Fund for upgrades that reduce the use of other fuels. This report presents the evaluation results for the electricity ratepayer portion of EPI only.

4.3.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	EPI__HVAC_HUMS_EPI_001__0
Measure ID (Incremental Cost)	N/A
Common Measure Name	Humidity Sensor
Sector	Residential
Program Name	Existing Residential
Program Component	Efficient Products Installation
Replacement Type	RET
Unit Basis	Per unit
DI Flag	1

4.3.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is the Humidity Sensor Measure[36] from the 2024-2025 DSM Residential Measure Assessment. The measure summary table from this section is reproduced below.

Table 112: Humidity Sensor for Bathroom Exhaust Fan Summary

Parameter	Instant Savings, EPI	Reference
Measure Description and Identification		
Measure	Added humidity sensors on existing bathroom exhaust fans with direct installation	-
Baseline	Existing fans with no controls	-
General Parameters		
Installation Rate	100%	See details below under Installation Rates.
Effective Useful Life [years]	9.5	See Subsection 3.2
Electrical Savings Parameters		
Unitary Energy Savings [kWh/year]	143	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0.1	See Subsection 2.4.2
Unitary Peak Demand Savings [W]	14.3	Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%	See Subsection 2.4.1
Interactive Effects Factor for Peak Demand Savings	0%	See Subsection 2.4.1

4.3.3 MEASURE LIFE

Value: 9.5 Years

Source: This value was drawn from Table 135[37] of the 2024 DSM Measure Assessment.

Humidity Sensor for Bathroom Exhaust Fans	EPI	9	Illinois TRM, 2024 (Half the value of High Efficiency Bathroom Exhaust Fan to account for remaining useful life of existing fan)

[36] 2024-2025 DSM Measure Assessment, Residential, Appliance Measures, Humidity Sensors for Bathroom Exhaust Fans, page 111 (PDF 1193/1442)

[37] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

4.3.4 NET TO GROSS

Value: 1.04

Source: This value was drawn from Table 37 of the 2024 Existing Residential Evaluation.[38]

Table 37: 2024 EPI Net-to-gross Ratios by Product Category

Products	Participant Type	NTGR	Proportion of Product Category Gross Savings by Participant Type	Overall NTGR Values
LED Lamps and Lighting Related Products	Non-low-income Participants	0.92	32%	0.97
	Low-income Participants	1.00	68%	
Smart and Advanced Learning Thermostats	Non-low-income Participants	0.99	49%	1.00
	Low-income Participants	1.00	51%	
DHW Products	Non-low-income Participants	0.97	35%	0.99
	Low-income Participants	1.00	65%	
Air Sealing Products	Non-low-income Participants	0.96	41%	0.98
	Low-income Participants	1.00	59%	
Smart Power Controllers	Non-low-income Participants	1.05	38%	1.02
	Low-income Participants	1.00	62%	
Humidity Sensors	Non-low-income Participants	1.08	51%	1.04
	Low-income Participants	1.00	49%	

4.3.5 DIRECT INSTALL COST

Value: $111.24 (in $2025)

Unit Basis: per unit

Source: Per E1 program tracking.

Details: This value is the average direct installation cost per measure from recent tracked program data, escalated for 2025.

4.3.6 SAVINGS

4.3.6.1 Energy Savings (kWh)

Value: 143

Source: Average savings value calculated using recent tracked savings for this measure.

Details: In practice, Electrical unitary energy savings are calculated using the following equation and the corresponding parameters set out in the 2024-2025 Measure Assessment.

[38] 2024 Existing Residential Evaluation, Table 37: 2024 EPI Net-to-gross Ratios by Product Category, page 111 (PDF 315/1442)

$$Energy\ Savings_{fan}\left[\frac{kWh}{year}\right] = \%\ Savings \times \left(HOU_{fan} \times CFM\left[\frac{ft^3}{min}\right] \times \frac{1}{\eta_{fan}}\right)$$

$$Energy\ Savings_{heating} =$$

$$= \times CFM\left[\frac{ft^3}{min}\right] \times \left(\left[0.028317\ \frac{m^3}{ft^3}\right] \times \rho\left[\frac{kg}{m^3}\right] \times C_p\left[\frac{J}{kg \cdot °C}\right] \times \left[\frac{1\ W \cdot sec}{1\ J}\right] \times \left[\frac{1\ min}{60\ sec}\right] \times \left[\frac{1\ kW}{1{,}000\ W}\right]\right) \times HOU_{heating} \times \Delta T \times \%_{Savings}$$

Table 113: Electrical Savings Values for Humidity Sensors for Bathroom Exhaust Fans

Parameter	Symbol	EPI	Reference
Fan Efficiency [CFM/W]	η_{fan}	3.5	ENERGY STAR min standard, 2024[175]
Savings Percentage	% Savings	50%	Demand controlled ventilation A case study for existing Swedish multifamily buildings, 2004[176]
Fan Exhaust Rate [CFM]	CFM	99.1	Weighted average from ENERGY STAR compliant model list and 2021 tracking sheet using the ENERGY STAR bathroom fan measure available in Instant Savings at the time. This was used as a proxy for the size of fan that consumers purchased
Annual Fan Operating Hours [hours/year]	HOU_{fan}	850	Vermont TRM, 2023[177]
Fan Energy Savings [kWh/year]	Energy Savings [kWh/year]	12.0	Calculation

4.3.6.2 Coincident Peak Demand Savings (kW)

Value: 0.0143

Source: This is the deemed unitary peak demand savings value for the Humidity Sensor Measure[39] in the 2024 Measure Assessment.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.1 – Evaluator calculated value).

[39] 2024-2025 DSM Measure Assessment, Residential, Appliance Measures, Humidity Sensors for Bathroom Exhaust Fans, page 111 (PDF 1193/1442)

4.4 EPI__HVAC_SMAT_EPI_001__0 | SMART THERMOSTATS FOR MINI-SPLIT HEAT PUMPS

EPI provides participants with free-of-charge direct installations of energy efficient products. EPI has played a pivotal role in transforming the residential lighting market by making energy-efficient products more affordable. Importantly, as LEDs have become the baseline, EPI is set to phase out lighting measures and focus on electrician-installed energy-efficient products. Electrician-installed measures will be key in delivering Residential Demand Response activities. E1 contracts service providers to deliver EPI across the province. EPI is available to both homeowners and renters and encourages participants to also consider other E1 residential program components.

Electrician-installed measures were introduced to EPI in 2024, except smart thermostats for electric baseboards and DHW heater load controllers that were introduced with a limited scope in 2023 as well as smart thermostats for MSHP that were introduced in 2022.

EPI funding comes from two sources: (1) Electricity ratepayer funding is used for upgrades that reduce electricity consumption; and (2) funding from the Government of Nova Scotia using funds from the Green Fund for upgrades that reduce the use of other fuels. This report presents the evaluation results for the electricity ratepayer portion of EPI only.

4.4.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	EPI__HVAC_SMAT_EPI_001__0
Measure ID (Incremental Cost)	N/A
Common Measure Name	Smart thermostats for mini-split heat pumps
Sector	Residential
Program Name	Existing Residential
Program Component	Efficient Products Installation
Replacement Type	RET
Unit Basis	Per unit
DI Flag	1

4.4.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is the Smart Thermostat for Electrical Heating Systems Measure[40] from the 2024-2025 DSM Residential Measure Assessment. The measure summary table from this section is reproduced below.

Table 73: Smart Thermostat for Electrical Heating System Measure Summary

Parameter	Instant Savings, MHEEP, ASFH		EPI				Reference
Measure Description and Identification							
Measure	Smart thermostats controlling electric baseboards, MSHP or electric in-floor heating						-
Baseline	Non-programmable thermostat						
Measure Subcategory	-		Single-family homes		Apartments		-
	Electric Baseboard or Electric In-floor Heating	MSHP	Electric Baseboard or Electric In-floor Heating	MSHP	Electric Baseboard or Electric In-floor Heating	MSHP	
General Parameters							
Installation Rate	100%		100%	84%	100%	84%	See details below under Installation Rates
Effective Useful Life [years]	10						See Subsection 3.2
Electrical Savings Parameters							
Unitary Energy Savings [kWh/year]	312	564	312	564	241	535	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0						See Subsection 2.3.2
Unitary Peak Demand Savings [W]	0						Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%						See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings							

[40] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

4.4.3 MEASURE LIFE

Value: 10 Years

Source: This value was drawn from Table 135[41] of the 2024 DSM Measure Assessment.

Smart Thermostats for Electrical Heating Systems	EPI, Instant Savings, MHEEP, ASFH	10	Various EUL values are used among jurisdictions. The common practice is to use the same EUL value as for programmable thermostats

4.4.4 NET TO GROSS

Value: 1.0

Source: This value was drawn from Table 37 of the 2024 Existing Residential Evaluation.[42]

Table 37: 2024 EPI Net-to-gross Ratios by Product Category

Products	Participant Type	NTGR	Proportion of Product Category Gross Savings by Participant Type	Overall NTGR Values
LED Lamps and Lighting Related Products	Non-low-income Participants	0.92	32%	**0.97**
	Low-income Participants	1.00	68%	
Smart and Advanced Learning Thermostats	Non-low-income Participants	0.99	49%	**1.00**
	Low-income Participants	1.00	51%	
DHW Products	Non-low-income Participants	0.97	35%	**0.99**
	Low-income Participants	1.00	65%	
Air Sealing Products	Non-low-income Participants	0.96	41%	**0.98**
	Low-income Participants	1.00	59%	
Smart Power Controllers	Non-low-income Participants	1.05	38%	**1.02**
	Low-income Participants	1.00	62%	
Humidity Sensors	Non-low-income Participants	1.08	51%	**1.04**
	Low-income Participants	1.00	49%	

4.4.5 DIRECT INSTALL COST

Value: $201.24 (in $2025)

Unit Basis: per unit

Source: Per E1 program tracking.

[41] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

[42] 2024 Existing Residential Evaluation, Table 37: 2024 EPI Net-to-gross Ratios by Product Category, page 111 (PDF 315/1442)

Details: This value is the average direct installation cost per measure from recent tracked program data, escalated for 2025.

4.4.6 SAVINGS

4.4.6.1 Energy Savings (kWh)

Value: 479.0

Source: This is the deemed unitary energy savings value for the Smart Thermostat for Electrical Heating Systems Measure in the 2025 Measure Assessment.

Details: Some models of smart thermostats sold through Instant Savings or installed through EPI or MHEEP are compatible with electrical heating systems. They operate by connecting to a single baseboard, MSHP, or in-floor heating system as opposed to a central heating system. In practice, the equation below is used to calculate the unitary savings value for smart thermostats compatible with electrical heating systems and installed through Instant Savings, EPI or MHEEP.

$$Energy\ Savings_{kWh} = \frac{Heating\ Energy \times \%Savings \times FMT}{COP}$$

Since no studies specific to smart thermostats connected to electric baseboards, MSHPs, or electric in-floor heating systems were identified, the percentage of the heating load saved by thermostats is based on available studies for smart thermostats compatible with central heating systems, which have essentially the same features. Table 72 presents two billing analyses conducted for Nest smart thermostats installed on central electrical heating systems (rather than natural gas or oil heating systems). Both analyses served to assess the savings for smart thermostats installed to replace both programmable and non-programmable thermostats, which is a reasonable baseline. In both studies, heating consumption savings of 12% were evaluated for central air-source heat pumps, which is the closest heating system to electric baseboards, MSHPs, and electric in-floor heating systems among Nest compatible systems.

Table 72: Non-learning Smart Thermostat for Electrical Heating System Measure Summary

Parameter	ASFH, Instant Savings		EPI						Reference
Measure Description and Identification									
Measure	Non-learning smart thermostats with programmable schedules through smart devices and additional sensor-based features (such as geofencing) that control electric baseboards, MSHPs, or electric in-floor heating for single-family homes and apartments as well as for central heating systems, namely central heat pumps or electric furnaces, for single-family homes								-
Baseline	Non-programmable thermostat								
Measure Subcategory	-		Single-family homes				Apartments		-
	Electric Baseboard or Electric In-floor Heating	MSHP	Electric Baseboard or Electric In-floor Heating	Electric Furnace	Central Heat Pump	MSHP	Electric Baseboard or Electric In-floor Heating	MSHP	
General Parameters									
Installation Rate	100%		100%			84%	100%	84%	See details below under Installation Rates
Effective Useful Life [years]	10								See Subsection 3.2
Electrical Savings Parameters									
Unitary Energy Savings [kWh/year]	265	479	265	1,725	959	479	205	455	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0								See Subsection 2.3.2
Unitary Peak Demand Savings [W]	0								Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%								See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings									

4.4.6.2 Coincident Peak Demand Savings (kW)

Value: 0.000

Source: This is the deemed unitary peak demand savings value for the Smart Thermostat for Electrical Heating Systems Measure[43] in the 2025 Measure Assessment.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.000 – Assumption based on literature review findings).

[43] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

4.5 EPI__HVAC_SMAT_EPI_002.5__0 | SMART THERMOSTATS FOR ELECTRIC BASEBOARDS - MURB

EPI provides participants with free-of-charge direct installations of energy efficient products. EPI has played a pivotal role in transforming the residential lighting market by making energy-efficient products more affordable. Importantly, as LEDs have become the baseline, EPI is set to phase out lighting measures and focus on electrician-installed energy-efficient products. Electrician-installed measures will be key in delivering Residential Demand Response activities. E1 contracts service providers to deliver EPI across the province. EPI is available to both homeowners and renters and encourages participants to also consider other E1 residential program components.

Electrician-installed measures were introduced to EPI in 2024, except smart thermostats for electric baseboards and DHW heater load controllers that were introduced with a limited scope in 2023 as well as smart thermostats for MSHP that were introduced in 2022.

EPI funding comes from two sources: (1) Electricity ratepayer funding is used for upgrades that reduce electricity consumption; and (2) funding from the Government of Nova Scotia using funds from the Green Fund for upgrades that reduce the use of other fuels. This report presents the evaluation results for the electricity ratepayer portion of EPI only.

4.5.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	EPI__HVAC_SMAT_EPI_002.5__0
Measure ID (Incremental Cost)	N/A
Common Measure Name	Smart thermostats for electric baseboards - MURB
Sector	Residential
Program Name	Existing Residential
Program Component	Efficient Products Installation
Replacement Type	RET
Unit Basis	Per unit
DI Flag	1

4.5.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is the Smart Thermostat for Electrical Heating Systems Measure[44] from the2025 Measure Assessment. The measure summary table from this section is reproduced below.

4.5.3 MEASURE LIFE

Value: 10 Years

Source: This value was drawn from Table 135[45] of the 2024 DSM Measure Assessment.

Smart Thermostats for Electrical Heating Systems	EPI, Instant Savings, MHEEP, ASFH	10	Various EUL values are used among jurisdictions. The common practice is to use the same EUL value as for programmable thermostats

4.5.4 NET TO GROSS

Value: 1.0

Source: This value was drawn from Table 37 of the 2024 Existing Residential Evaluation.[46]

Table 37: 2024 EPI Net-to-gross Ratios by Product Category

Products	Participant Type	NTGR	Proportion of Product Category Gross Savings by Participant Type	Overall NTGR Values
LED Lamps and Lighting Related Products	Non-low-income Participants	0.92	32%	**0.97**
	Low-income Participants	1.00	68%	
Smart and Advanced Learning Thermostats	Non-low-income Participants	0.99	49%	**1.00**
	Low-income Participants	1.00	51%	
DHW Products	Non-low-income Participants	0.97	35%	**0.99**
	Low-income Participants	1.00	65%	
Air Sealing Products	Non-low-income Participants	0.96	41%	**0.98**
	Low-income Participants	1.00	59%	
Smart Power Controllers	Non-low-income Participants	1.05	38%	**1.02**
	Low-income Participants	1.00	62%	
Humidity Sensors	Non-low-income Participants	1.08	51%	**1.04**
	Low-income Participants	1.00	49%	

[44] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

[45] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

[46] 2024 Existing Residential Evaluation, Table 37: 2024 EPI Net-to-gross Ratios by Product Category, page 111 (PDF 315/1442)

4.5.5 DIRECT INSTALL COST

Value: $146.28 (in $2025)

Unit Basis: per unit

Source: Per E1 program tracking.

Details: This value is the average direct installation cost per measure from recent tracked program data, escalated for 2025.

4.5.6 SAVINGS

4.5.6.1 Energy Savings (kWh)

Value: 205

Source: This is the deemed unitary energy savings value for the Smart Thermostat for Electrical Heating Systems Measure in the 2025 Measure Assessment.

Details: Some models of smart thermostats sold through Instant Savings or installed through EPI or MHEEP are compatible with electrical heating systems. They operate by connecting to a single baseboard, MSHP, or in-floor heating system as opposed to a central heating system. In practice, the equation below is used to calculate the unitary savings value for smart thermostats compatible with electrical heating systems and installed through Instant Savings, EPI or MHEEP.

$$Energy\ Savings_{kWh} = \frac{Heating\ Energy \times \%Savings \times FMT}{COP}$$

Since no studies specific to smart thermostats connected to electric baseboards, MSHPs, or electric in-floor heating systems were identified, the percentage of the heating load saved by thermostats is based on available studies for smart thermostats compatible with central heating systems, which have essentially the same features. Table 74 presents two billing analyses conducted for Nest smart thermostats installed on central electrical heating systems (rather than natural gas or oil heating systems). Both analyses served to assess the savings for smart thermostats installed to replace both programmable and non-programmable thermostats, which is a reasonable baseline. In both studies, heating consumption savings of 12% were evaluated for central air-source heat pumps, which is the closest heating system to electric baseboards, MSHPs, and electric in-floor heating systems among Nest compatible systems.

Table 74: Billing Analysis Savings Results for Smart Thermostats for Electrical Heating Systems

Jurisdiction	Measure	Sample Size	Heating Consumption Savings
Oregon[105]	Nest thermostats	185	12% (for ASHPs)
Bonneville Power Administration[106]	Nest thermostats	176	12% (for ASHPs)

4.5.6.2 Coincident Peak Demand Savings (kW)

Value: 0.000

Source: This is the deemed unitary peak demand savings value for the Smart Thermostat for Electrical Heating Systems Measure[47] in the 2025 Measure Assessment.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.000 – Assumption based on literature review findings).

[47] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

4.6 EPI__HVAC_SMAT_EPI_002__0 | SMART THERMOSTATS FOR ELECTRIC BASEBOARDS

EPI provides participants with free-of-charge direct installations of energy efficient products. EPI has played a pivotal role in transforming the residential lighting market by making energy-efficient products more affordable. Importantly, as LEDs have become the baseline, EPI is set to phase out lighting measures and focus on electrician-installed energy-efficient products. Electrician-installed measures will be key in delivering Residential Demand Response activities. E1 contracts service providers to deliver EPI across the province. EPI is available to both homeowners and renters and encourages participants to also consider other E1 residential program components.

Electrician-installed measures were introduced to EPI in 2024, except smart thermostats for electric baseboards and DHW heater load controllers that were introduced with a limited scope in 2023 as well as smart thermostats for MSHP that were introduced in 2022.

EPI funding comes from two sources: (1) Electricity ratepayer funding is used for upgrades that reduce electricity consumption; and (2) funding from the Government of Nova Scotia using funds from the Green Fund for upgrades that reduce the use of other fuels. This report presents the evaluation results for the electricity ratepayer portion of EPI only.

4.6.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	EPI__HVAC_SMAT_EPI_002__0
Measure ID (Incremental Cost)	N/A
Common Measure Name	Smart thermostats for electric baseboards
Sector	Residential
Program Name	Existing Residential
Program Component	Efficient Products Installation
Host Proxy	Other Equipment Energy Efficiency
Replacement Type	RET
Unit Basis	Per unit
DI Flag	1

4.6.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is the Smart Thermostat for Electrical Heating Systems Measure[48] from the 025 DSM Residential Measure Assessment. The measure summary table from this section is reproduced below.

4.6.3 MEASURE LIFE

Value: 10 Years

Source: This value was drawn from Table 135[49] of the 2024 DSM Measure Assessment.

Smart Thermostats for Electrical Heating Systems	EPI, Instant Savings, MHEEP, ASFH	10	Various EUL values are used among jurisdictions. The common practice is to use the same EUL value as for programmable thermostats

4.6.4 NET TO GROSS

Value: 1.0

Source: This value was drawn from Table 37 of the 2024 Existing Residential Evaluation.[50]

Table 37: 2024 EPI Net-to-gross Ratios by Product Category

Products	Participant Type	NTGR	Proportion of Product Category Gross Savings by Participant Type	Overall NTGR Values
LED Lamps and Lighting Related Products	Non-low-income Participants	0.92	32%	**0.97**
	Low-income Participants	1.00	68%	
Smart and Advanced Learning Thermostats	Non-low-income Participants	0.99	49%	**1.00**
	Low-income Participants	1.00	51%	
DHW Products	Non-low-income Participants	0.97	35%	**0.99**
	Low-income Participants	1.00	65%	
Air Sealing Products	Non-low-income Participants	0.96	41%	**0.98**
	Low-income Participants	1.00	59%	
Smart Power Controllers	Non-low-income Participants	1.05	38%	**1.02**
	Low-income Participants	1.00	62%	
Humidity Sensors	Non-low-income Participants	1.08	51%	**1.04**
	Low-income Participants	1.00	49%	

[48] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

[49] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

[50] 2024 Existing Residential Evaluation, Table 37: 2024 EPI Net-to-gross Ratios by Product Category, page 111 (PDF 315/1442)

4.6.5 DIRECT INSTALL COST

Value: $146.25 (in $2025)

Unit Basis: per unit

Source: Per E1 program tracking.

Details: This value is the average direct installation cost per measure from recent tracked program data, escalated for 2025.

4.6.6 SAVINGS

4.6.6.1 Energy Savings (kWh)

Value: 265

Source: This is the deemed unitary energy savings value for the Smart Thermostat for Electrical Heating Systems Measure in the 2025 Measure Assessment.

Details: Some models of smart thermostats sold through Instant Savings or installed through EPI or MHEEP are compatible with electrical heating systems. They operate by connecting to a single baseboard, MSHP, or in-floor heating system as opposed to a central heating system. In practice, the equation below is used to calculate the unitary savings value for smart thermostats compatible with electrical heating systems and installed through Instant Savings, EPI or MHEEP.

$$Energy\ Savings_{kWh} = \frac{Heating\ Energy \times \%Savings \times FMT}{COP}$$

Since no studies specific to smart thermostats connected to electric baseboards, MSHPs, or electric in-floor heating systems were identified, the percentage of the heating load saved by thermostats is based on available studies for smart thermostats compatible with central heating systems, which have essentially the same features. Table 74 presents two billing analyses conducted for Nest smart thermostats installed on central electrical heating systems (rather than natural gas or oil heating systems). Both analyses served to assess the savings for smart thermostats installed to replace both programmable and non-programmable thermostats, which is a reasonable baseline. In both studies, heating consumption savings of 12% were evaluated for central air-source heat pumps, which is the closest heating system to electric baseboards, MSHPs, and electric in-floor heating systems among Nest compatible systems.

Table 74: Billing Analysis Savings Results for Smart Thermostats for Electrical Heating Systems

Jurisdiction	Measure	Sample Size	Heating Consumption Savings
Oregon[105]	Nest thermostats	185	12% (for ASHPs)
Bonneville Power Administration[106]	Nest thermostats	176	12% (for ASHPs)

4.6.6.2 Coincident Peak Demand Savings (kW)

Value: 0.000

Source: This is the deemed unitary peak demand savings value for the Smart Thermostat for Electrical Heating Systems Measure[51] in the 2024 Measure Assessment.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.000 – Assumption based on literature review findings).

[51] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

4.7 EPI__WNDW_FLM_EPI_001__0 | WINDOW FILM KITS

EPI provides participants with free-of-charge direct installations of energy efficient products. EPI has played a pivotal role in transforming the residential lighting market by making energy-efficient products more affordable. Importantly, as LEDs have become the baseline, EPI is set to phase out lighting measures and focus on electrician-installed energy-efficient products. Electrician-installed measures will be key in delivering Residential Demand Response activities. E1 contracts service providers to deliver EPI across the province. EPI is available to both homeowners and renters and encourages participants to also consider other E1 residential program components.

Electrician-installed measures were introduced to EPI in 2024, except smart thermostats for electric baseboards and DHW heater load controllers that were introduced with a limited scope in 2023 as well as smart thermostats for MSHP that were introduced in 2022.

EPI funding comes from two sources: (1) Electricity ratepayer funding is used for upgrades that reduce electricity consumption; and (2) funding from the Government of Nova Scotia using funds from the Green Fund for upgrades that reduce the use of other fuels. This report presents the evaluation results for the electricity ratepayer portion of EPI only.

4.7.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	EPI__WNDW_FLM_EPI_001__0
Measure ID (Incremental Cost)	N/A
Common Measure Name	Window Film Kits
Sector	Residential
Program Name	Existing Residential
Program Component	Efficient Products Installation
Replacement Type	RET
Unit Basis	Per window film kit (2 windows)
DI Flag	1

4.7.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary source of the values for measure input development is the Window Film Kit Measure[52] from the 2024-2025 DSM Residential Measure Assessment. The measure summary table from this section is reproduced below.

Table 69: Window Film Kit Measure Summary

Parameter	EPI		Reference
Measure Description and Identification			
Measure	Window film kits installed by the participant (left behind by the delivery agent), in electrically heated homes		-
Baseline	Windows without film kits		
Measure Subcategory	Electrical Resistance Heated Homes	Heat Pump Heated Homes	
General Parameters			
Installation Rate	57%		2024 Illinois TRM[96]
Effective Useful Life [years]	1		See Subsection 3.2
Electrical Savings Parameters			
Unitary Energy Savings [kWh/year]	334	185	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0.283		See Subsection 2.3.2
Unitary Peak Demand Savings [W]	94.5	52.4	Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%		See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings	0%		See Subsection 2.3.1

4.7.3 MEASURE LIFE

Value: 1 Year

Source: This value was drawn from Table 135[53] of the 2024 DSM Measure Assessment.

Window Film Kits	EPI	1	Assumption based on the unlikeliness that the same film would be removed and reapplied every year without it being damaged and replaced over time

[52] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Window Film Kits, page 72 (PDF 1154/1442)
[53] 2024-2025 DSM Measure Assessment, Residential, Effective Useful Life, Other Measures, Table 135: EUL Values and Sources for Non-LED Lighting Residential Measures, page 130 (PDF 1212/1442)

4.7.4 NET TO GROSS

Value: 0.98

Source: This value was drawn from Table 37 of the 2024 Existing Residential Evaluation.[54]

Table 37: 2024 EPI Net-to-gross Ratios by Product Category

Products	Participant Type	NTGR	Proportion of Product Category Gross Savings by Participant Type	Overall NTGR Values
LED Lamps and Lighting Related Products	Non-low-income Participants	0.92	32%	0.97
	Low-income Participants	1.00	68%	
Smart and Advanced Learning Thermostats	Non-low-income Participants	0.99	49%	1.00
	Low-income Participants	1.00	51%	
DHW Products	Non-low-income Participants	0.97	35%	0.99
	Low-income Participants	1.00	65%	
Air Sealing Products	Non-low-income Participants	0.96	41%	0.98
	Low-income Participants	1.00	59%	
Smart Power Controllers	Non-low-income Participants	1.05	38%	1.02
	Low-income Participants	1.00	62%	
Humidity Sensors	Non-low-income Participants	1.08	51%	1.04
	Low-income Participants	1.00	49%	

4.7.5 DIRECT INSTALL COST

Value: $7.90 (in $2025)

Unit Basis: per unit

Source: Per E1 program tracking.

Details: This value is the average direct installation cost per measure from recent tracked program data, escalated for 2025.

4.7.6 SAVINGS

4.7.6.1 Energy Savings (kWh)

Value: 128.92

Source: Value based on actual tracked savings from 2024.

Details: In practice, the electrical unitary energy savings are calculated using the equations below.

[54] 2024 Existing Residential Evaluation, Table 37: 2024 EPI Net-to-gross Ratios by Product Category, page 111 (PDF 315/1442)

$$Energy\ Savings\ (kWh) = ES_{sealing} + ES_{insulation}$$

$$ES_{sealing} = \frac{n_{window} \times p_{window} \times ESPF_{tape}}{COP} \times \frac{HDD_{NS}}{HDD_{CT}}$$

$$ES_{insulation} = \frac{HDD_{NS} \times n_{window} \times A_{window} \times 24 \times ADJ}{COP \times 3{,}413} \times \left(\frac{1}{R_{window}} - \frac{1}{R_{window} + R_{air}}\right)$$

Total energy savings for this measure are calculated by combining savings from insulation and sealing; for the number of units, it is assumed that each kit could be used to cover two two-foot by three-foot windows.

The energy savings per foot of tape (ESPF) used in the second equation for sealing was taken from Connecticut's 2021 Program Savings Document; the value was adjusted to the Nova Scotia context by using a heating degree days (HDD) ratio between Connecticut and Nova Scotia.

For the savings generated by insulation, the resistance values of the window and the added air layer due to film shrinkage (Rwindow + Rair) were based on specific values provided by the 2022 Iowa Energy Efficiency Statewide Technical Reference Manuel. That TRM also provides an adjustment factor of 0.63 for wall insulation, used to account for overclaiming savings due to prescriptive engineering algorithms.

Table 70: Electrical Unitary Savings Calculations for Window Film Kits

Parameter	Symbol	Value for Electrical Resistance Heated Homes	Value for Heat Pump Heated Homes	
Number of Windows Insulated	n_{window}	2		Assumption that one window kit can typically cover two 2'x3' windows
Perimeter of Insulated Window [ft]	p_{window}	10		
Net Area of Insulated Window [ft^2]	A_{window}	6		
Average Annual Heating Degree Days in Connecticut [°F·day]	HDD_{CT}	5,885		2021 Connecticut Program Savings Document, 18th Edition, p. 242
Average Annual Heating Degree Days in Nova Scotia [°F·day]	HDD_{NS}	6,765		Environment Canada, Halifax Stanfield International Airport, using an 18 °C heating balance point
Coefficient of Performance	COP	1	1.8	
Energy Savings per Foot of Tape [kWh/ft]	$EPSF_{tape}$	9.9		2021 Connecticut Program Savings Document, 18th Edition, p. 248
R-value of Existing Window [ft^2·°F·h/Btu]	R_{window}	2		2022 Iowa TRM, Volume 2, p. 307
R-value of existing window [ft^2·°F·h/Btu]	R_{air}	2.85		
Adjustment to Account for Overclaiming of Savings [%]	ADJ	63%		
Energy Savings from Air Sealing Provided by the Tape [kWh]	$ES_{sealing}$	228	126	Calculation
Energy Savings from Insulation Provided by the Film [kWh]	$ES_{insulation}$	106	58.7	
Unitary Energy Savings [kWh/year]	$Energy\ Savings_{kWh}$	**334**	**185**	**Calculation**

4.7.6.2 Coincident Peak Demand Savings (kW)

Value: 0.036

Source: Value based on actual tracked savings from 2024.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.283 – RES-Elec-Space Heat & Cool, Navigant 2016-2018 DSM Plan).

4.8 HEA_HVAC_BE_CI | HEA BUILDING ENVELOPE - CUSTOMER INSTALLED

HEA is a home energy evaluation-based program component that encourages homeowners to improve the energy efficiency and comfort of their homes by providing them with related information and financial incentives in the form of rebates. HEA uses the EnerGuide home evaluation framework and is administered in collaboration with Natural Resources Canada (NRCan).

In May 2021, the federal government announced the launch of the Canada Greener Homes (CGH) Grant. The initiative offered grants of up to $5,000 to help homeowners implement energy efficiency retrofits in their primary residences. In Nova Scotia, the CGH Grant was co-delivered by E1 through HEA. On 5 February 2024, the CGH Grant was closed to new applications, which means that measures solely funded by the CGH Grant, namely resiliency measures (batteries for solar PV, roofing membranes, foundation water proofing, and moisture proofing), solar PV, and smart thermostats, are no longer available for applicants after this date.

At the end of 2022, low uptake measures (air-to-water heat pumps, solar air equipment, and drain water heat recovery) as well as demand reduction measures (electric thermal storage [ETS] units, three-element water heaters, domestic hot water [DHW] heater timers) were removed from the offering. Rebates for those measures are honoured for customers who enrolled prior to these changes taking effect.

4.8.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	HEA_HVAC_BE_CI
Measure ID (Incremental Cost)	HEA_HVAC_BE_CI
Common Measure Name	HEA Building Envelope - Customer Installed
Sector	Residential
Program Name	Existing Residential
Program Component	Home Energy Assessment
Replacement Type	RET
Unit Basis	Per home
DI Flag	0

4.8.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below.

4.8.3 MEASURE LIFE

Value: 20.5 Years

Source: This value was drawn from Table 59[55] of the 2024 Existing Residential Evaluation.

Table 59: 2024 HEA Tracked and Evaluated Effective Useful Life Values

Measure	Tracked EUL [years]	Evaluated EUL [years]
Measures Modelled in HOT2000 (i.e. Heat Pumps and Building Envelope Measures)	20.8	20.5
Heat Pump Water Heaters	10.0	15.0
Solar PV	25.0	30.0

4.8.4 NET TO GROSS

Value: 0.84

Source: Value drawn from the 2024 Existing Residential Evaluation, Net Savings, Table 64: 2024 HEA NTGR Values, page 162 (PDF 336/1442).

Table 64: 2024 HEA NTGR Values

Measure	Free-ridership	Participant Spillover	NTGR
Energy Efficiency Measures	17%	1%	0.84
Solar PV Measures	26%		0.75

4.8.5 INCREMENTAL COST

Value: 2,085.91 (in 2025, escalated in out years)

Unit Basis: per project

Source: Per E1 program tracking.

Details: This value is an average cost per measure developed using recent tracked program delivery cost data. Input values were developed using a weighted $/kWh value developed using recent tracked direct

[55] 2024 Existing Residential Evaluation, Effective Useful Life, Table 59: 2024 HEA Tracked and Evaluated Effective Useful Life Values, page 159 (PDF 363/1442)

installation costs from both ASFH & MHEEP. The $/kWh value was scaled against the claimed savings in HEA to determine an estimate of the project cost associated with this amount of savings.

4.8.6 SAVINGS

4.8.6.1 Energy Savings (kWh)

Value: 1033

Source: Per E1 program tracking and Adjustment Ratios (AR) found in 2024 Existing Residential Evaluation Report (Tables 16, Table 54, and Table 71). The 1,033 kWh value was derived from adjusted program tracking results. The data were drawn exclusively from 2025 projects for homes that are predominantly electrically heated and that did not include space-heating upgrades (building envelope measures only).

Details: In practice, HEA energy savings are calculated based on HOT2000 simulation results adjusted with billing analysis results and unitary savings values for prescriptive measures, as shown in the equation below.

$$Gross\ Energy\ Savings\ (kWh) = (Total\ Elec_D(kWh) - Total\ Elec_E(kWh) - HPWH\ (kWh)) \times AR + Savings\ for\ Prescriptive\ Measures\ (kWh)$$

Where:

- $Total\ ElecD$ and $Total\ ElecE$ correspond to the modelled electrical energy consumption levels respectively obtained in HOT2000 during the D and E assessments.
- $HPWH\ (kWh)$ correspond to the unitary savings value established for heat pump water heaters (HPWHs).
- AR correspond to the adjustment ratio established through a billing analysis and used to adjust the savings obtained from the difference between the modelled electrical energy consumption during the D and E assessments. Adjustment ratios vary according to different space heating system scenarios.
- $Savings\ for\ Prescriptive\ Measures$ are obtained by multiplying the prescriptive measures installed through HEA by their respective unitary electrical energy savings value.

After the D and E home energy assessments, EAs model the house in the HOT2000 energy simulation software to obtain the initial and final EnerGuide ratings of the given house. Energy consumption levels obtained from HOT2000 simulation results are used to determine the electrical energy savings for modelled measures. They correspond to the reduction in consumption level between the D and E assessments.

The methodology currently used to calculate tracked savings compares electrical space heating consumption levels for the two assessments, both of which are adjusted with an overestimation ratio (OR).

4.8.6.2 Coincident Peak Demand Savings (kW)

Value: 0.314

Source: This value was from tracked 2025 HEA data for homes that only received building envelope upgrades.

Details: In practice, for measures modelled in HOT2000, peak demand savings are calculated by applying a peak demand-to-energy ratio of 0.283 MW/GWh after having removed the energy savings associated with mini-split heat pumps.

Table 52: Peak Demand-to-energy Ratios for Space Heating Measures

Measure	Peak Demand-to-energy Ratio (W/kWh)	Reference
Mini-split Heat Pumps (MSHPs)	-	-
Central Air-source Heat Pumps		
Ground-source Heat Pumps		
Wood and Pellet Stoves/Fireplace Inserts		
Wood and Pellet Furnaces/Boilers		
Solar Air Heating	0.000	Assumption
Air Sealing Products	0.283	RES-Elec-Space Heat & Cool, Navigant 2016-2018 DSM Plan
Programmable Thermostats	0.000	Assumption based on literature review findings
Smart Thermostats		
Modelled Space Heating and Building Envelope	0.283	RES-Elec-Space Heat & Cool, Navigant 2016-2018 DSM Plan

4.9 HEA_HVAC_HP_CI | HEA HEAT PUMP - CUSTOMER INSTALLED

HEA is a home energy evaluation-based program component that encourages homeowners to improve the energy efficiency and comfort of their homes by providing them with related information and financial incentives in the form of rebates. HEA uses the EnerGuide home evaluation framework and is administered in collaboration with Natural Resources Canada (NRCan).

In May 2021, the federal government announced the launch of the Canada Greener Homes (CGH) Grant. The initiative offered grants of up to $5,000 to help homeowners implement energy efficiency retrofits in their primary residences. In Nova Scotia, the CGH Grant was co-delivered by E1 through HEA. On 5 February 2024, the CGH Grant was closed to new applications, which means that measures solely funded by the CGH Grant, namely resiliency measures (batteries for solar PV, roofing membranes, foundation water proofing, and moisture proofing), solar PV, and smart thermostats, are no longer available for applicants after this date.

At the end of 2022, low uptake measures (air-to-water heat pumps, solar air equipment, and drain water heat recovery) as well as demand reduction measures (electric thermal storage [ETS] units, three-element water heaters, domestic hot water [DHW] heater timers) were removed from the offering. Rebates for those measures are honoured for customers who enrolled prior to these changes taking effect.

4.9.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	HEA_HVAC_HP_CI
Measure ID (Incremental Cost)	HEA_HVAC_HP_CI
Common Measure Name	HEA Heat Pump - Customer Installed
Sector	Residential
Program Name	Existing Residential
Program Component	Home Energy Assessment
Replacement Type	RET
Unit Basis	Per unit
DI Flag	0

4.9.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below.

4.9.3 MEASURE LIFE

Value: 18 Years

Source: This value was drawn from Table 53[56] of the 2024 Residential DSM Measure Assessment.

Table 53: Mini-split Heat Pump Measure Summary

Parameter	Green Heat, ASFH		HEA	MHEEP	Reference
Measure Description and Identification					
Measure	Mini-split heat pumps for high-efficiency space heating with direct installation (HEA, MHEEP) or rebated after purchase (Green Heat)				-
Baseline	Electric resistance space heating				
Application	Fully electrically heated households	Mainly electrically heated households	-		
General Parameters					
Installation Rate	100%				See details below under Installation Rates
Effective Useful Life [years]	18				See Subsection 3.2
Electrical Savings Parameters					
Unitary Energy Savings [kWh/year]	0.0855 kWh/Btu/h multiplied by the heating capacity of each installed system	0.000 kWh/Btu/h multiplied by the heating capacity of each installed system	Calculated using HOT2000 modelling with an adjustment ratio		See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	N/A				
Unitary Peak Demand Savings [W]	Calculation based on specification data for each installed system			0.148 W/Btu/h multiplied by the heating capacity of each installed system	See details below under Unitary Peak Demand Savings
Interactive Effects Factor for Energy Savings	0%				See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings	0%				See Subsection 2.3.1

4.9.4 NET TO GROSS

Value: 0.84

Source: Value drawn from the 2024 Existing Residential Evaluation, Net Savings, Table 64: 2024 HEA NTGR Values, page 162 (PDF 336/1442).

[56] 2024-2025 DSM Measurement Assessment - Residential, Table 53: Mini-split Heat Pump Measure Summary, page 55 (PDF 72/159)

Table 64: 2024 HEA NTGR Values

Measure	Free-ridership	Participant Spillover	NTGR
Energy Efficiency Measures	17%	1%	0.84
Solar PV Measures	26%		0.75

4.9.5 INCREMENTAL COST

Value: $5,610.55 (in $2025)

Unit Basis: per project

Source: Per E1 program tracking.

Details: This value is an average cost per measure developed using recent tracked program delivery cost data.

4.9.6 SAVINGS

4.9.6.1 Energy Savings (kWh)

Value: 912

Source: The energy savings value currently tracked for mini-split heat pumps is based on Green Heat. The value was updated as part of this (2024) evaluation based on the billing analysis conducted for HEA. Treatment participants who only installed a mini-split heat pump through their participation in HEA were isolated to calculate an average energy savings value per capacity installed of 0.0760 kWh/Btu/h. See 2024 DSM Evaluation- Existing Residential Program, page 157 (PDF 183/229).

Description	Value	Unit	Source
Energy Savings per Btu/h	0.076	kWh/Btu/H	pdf page 183/229
kW/ kWh Ratio	0.00159		Calculated from Table 21
Energy Savings per ton	912	kWh/Ton	Calculated
Peak demand savings per ton	1.449	kW/Ton	Calculated

Details: In practice, HEA energy savings are calculated based on HOT2000 simulation results adjusted with billing analysis results and unitary savings values for prescriptive measures, as shown in the equation below.

$$Gross\ Energy\ Savings\ (kWh) =$$

$$(Total\ Elec_D(kWh) - Total\ Elec_E(kWh) - HPWH\ (kWh)) \times AR + Savings\ for\ Prescriptive\ Measures\ (kWh)$$

Where:

- $Total\ ElecD$ and $Total\ ElecE$ correspond to the modelled electrical energy consumption levels respectively obtained in HOT2000 during the D and E assessments.
- $HPWH\ (kWh)$ correspond to the unitary savings value established for heat pump water heaters (HPWHs).
- AR correspond to the adjustment ratio established through a billing analysis and used to adjust the savings obtained from the difference between the modelled electrical energy consumption during the D and E assessments. Adjustment ratios vary according to different space heating system scenarios.
- $Savings\ for\ Prescriptive\ Measures$ are obtained by multiplying the prescriptive measures installed through HEA by their respective unitary electrical energy savings value.

After the D and E home energy assessments, EAs model the house in the HOT2000 energy simulation software to obtain the initial and final EnerGuide ratings of the given house. Energy consumption levels obtained from HOT2000 simulation results are used to determine the electrical energy savings for modelled measures. They correspond to the reduction in consumption level between the D and E assessments.

The methodology currently used to calculate tracked savings compares electrical space heating consumption levels for the two assessments, both of which are adjusted with an overestimation ratio (OR).

4.9.6.2 Coincident Peak Demand Savings (kW)

Value: 1.450

Source: This value was derived in part from 2024 evaluated non-modelled heat pumps in the HomeWarming program. See Table 22[57] of the 2024 Existing Residential Evaluation Report.

Table 22: Evaluated 2024 ASFH Gross Electrical Energy and Peak Demand Savings

Measure Category	Modelled Measures	Non-modelled Heat Pumps	Smart Thermostats	Appliance Replacements	Total
Number of Participants with Savings*	**880**	**254**	**79**	**-**	**1,193**
Energy Savings					
Gross Energy Savings – at the Meter (GWh)	**3.111**	**0.197**	**0.049**	**0.041**	**3.398**
Line Loss Factor	1.0947	1.0947	1.0947	1.0947	-
Gross Energy Savings – at the Generator (GWh)	**3.406**	**0.216**	**0.053**	**0.045**	**3.719**
Effective Useful Life (years)**	20.5	18.0	10.0	4.4	-
Gross Lifetime Energy Savings – at the Generator (GWh)	**69.817**	**3.883**	**0.531**	**0.197**	**74.428**
Peak Demand Savings					
Gross Peak Demand Savings – at the Meter (MW)	**1.501**	**0.313**	**-**	**0.007**	**1.822**
Line Loss Factor	1.1466	1.1466	1.1466	1.1466	-
Gross Peak Demand Savings – at the Generator (MW)	**1.722**	**0.359**	**-**	**0.008**	**2.089**

*The total number of participants does not correspond to the sum of all measure categories since participants who benefited from appliance replacements also implemented additional measures.

** Corresponds to the equivalent EUL obtained from dividing the non-modelled measure lifetime energy savings at the meter by the energy savings at the meter (see Table 21).

Details: This value was calculated by multiplying the peak demand-to-energy ratio by the unitary energy savings of 912 kWh.

Input	Description	Total
A	Gross Energy Savings at the Meter for Non-modelled Heat Pumps (GWh)	0.197
B	Gross Peak Demand Savings at the Meter for Non-modelled Heat Pumps (MW)	0.313
C = (B / A)/1000	Peak demand to energy ratio (kW/GWh)	0.00159
D = C*Energy Savings	Coincident Peak Demand Savings (kW)	1.450

[57] 2024-2025 DSM Measurement Assessment - Residential, Table 53: Mini-split Heat Pump Measure Summary, page 55 (PDF 72/159)

4.10 HW_BE_EI | HW BUILDING ENVELOPE - E1 INSTALLED

ASFH provides energy efficient retrofits and heat pump installations to income-qualified Nova Scotian owners of both electrically heated and non-electrically heated homes at no cost to participants. The program component is marketed under the HomeWarming brand and mainly provides building envelope measures such as draft-proofing and insulation for basements, crawl spaces, exposed floors, main walls, and attics. Heat pumps and smart thermostats are also offered under ASFH. Moisture management measures such as bathroom fans, dehumidifiers, and dirt floor coverings may also be provided. Retrofits are selected and implemented on a case-by-case basis.

HomeWarming has evolved to provide energy efficiency services for both electrically and non-electrically heated homes. Initially launched in 2012, HomeWarming focused on non-electrically heated homes through government funding, while ASFH, introduced in 2023, targets homes primarily heated with electricity using DSM-approved funding.

Starting on 1 January 2023, E1 assumed full responsibility for HomeWarming delivery, regardless of heating source, and introduced a heat pump only stream for past participants to apply for the new heat pump measure, excluding an energy assessment and additional building envelope upgrades.

ASFH is supported across Nova Scotia by seven delivery agents (DAs) and 43 heat pump contractors who conduct most of the field work. DAs use energy advisors (EAs) to perform pre-retrofit and post-retrofit energy assessments. Pre-retrofit assessments (D assessments) serve to examine the house, provide homeowners with a better understanding of how their house functions in relation to space heating, and identify applicable energy efficient upgrades to be implemented. EAs generate home energy assessment reports that provide a high-level overview of energy usage and send them to homeowners. DAs then recommend retrofits to E1 and complete those approved by the latter. Lastly, EAs conduct post-retrofit assessments (E assessments) to verify implemented measures and provide a final EnerGuide rating calculated using HOT2000, a simulation tool developed by Natural Resources Canada (NRCan). In the heat pump only stream, heat pump contractors conduct an initial home visit and make recommendations for the heat pump measure to E1. Once approved by E1, the heat pump contractor manages the installation of the heat pump and any electrical upgrades required to facilitate the installation.

ASFH participants are also eligible for the Efficient Product Installation (EPI) program component through which energy efficient products are installed at no cost to participants. ASFH participants are internally referred to EPI and generally participate in EPI before receiving a pre-retrofit energy assessment under ASFH.

HomeWarming participants who currently heat their homes with oil can also take advantage of funding available through the Oil to Heat Pump Affordability (OHPA) program to transition from oil systems to electric cold climate heat pumps if they meet OHPA program eligibility criteria (e.g., minimum annual oil usage). OHPA is a federal government program delivered through specific Efficiency Nova Scotia programs. Some ASFH participants who receive DSM support and have electric savings, may also be eligible for the OHPA program and participate in both (e.g., this can be seen when a home has electric and oil heating).

4.10.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	HW_BE_EI
Measure ID (Incremental Cost)	HW_BE_EI
Common Measure Name	HW Building Envelope - E1 Installed
Sector	Residential
Program Name	Existing Residential
Program Component	Affordable Single-Family Homes
Replacement Type	RET
Unit Basis	Per home
DI Flag	1

4.10.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below.

4.10.3 MEASURE LIFE

Value: 20.5 Years

Source: This value was drawn from Table 19[58] of the 2024 Existing Residential Evaluation.

[58] 2024 Existing Residential Evaluation, Effective Useful Life, Table 19: Tracked and Evaluated 2024 ASFH Equivalent EUL Values, page 65 (PDF 269/1442)

Table 19: Tracked and Evaluated 2024 ASFH Equivalent EUL Values

Measure	Tracked Equivalent EUL [years]	Evaluated Equivalent EUL [years]
Building Envelope (Modelled)	20.8	20.5
Space Heating Equipment (Modelled)	20.8	20.5

4.10.4 NET TO GROSS

Value: 1.0

Source: For ASFH, free-ridership and spillover effects are considered to be nil since participants are non-profit organizations or low-income housing owners that traditionally have small housing budgets spread across many competing housing priorities. Therefore, a NTGR of 1.00 is applied.

4.10.5 DIRECT INSTALL COST

Value: $7,280.00 (in $2025)

Unit Basis: per project

Source: Per E1 program tracking.

Details: This value is an average cost per measure developed using recent tracked program delivery cost data.

4.10.6 SAVINGS

4.10.6.1 Energy Savings (kWh)

Value: 2,576

Source: Per E1 program tracking and Adjustment Ratios (AR) found in 2024 Existing Residential Evaluation Report (Tables 16, Table 54, and Table 71). The 2,576 kWh value was derived from adjusted program tracking results. The data were drawn exclusively from 2025 projects for homes that are predominantly electrically heated and that did not include space-heating upgrades (building envelope measures only).

Details: In practice, electrical energy savings are calculated based on HOT2000 simulation results adjusted with billing analysis results and unitary savings values for prescriptive measures, as shown in the equation below.

$$Gross\ Energy\ Savings\ (kWh) = \left(\frac{\left(Total\ Energy_D(GJ) - Total\ Energy_E(GJ)\right)}{0.0036\ GJ/kWh} \times \%_{Elec}\right) \times AR + Savings\ for\ Non\text{-}modelled\ Measures\ (kWh)$$

Where:

- $Total\ EnergyD$ and $Total\ EnergyE$ correspond to the modelled energy consumption levels obtained in HOT2000 during the pre-retrofit (D) and post-retrofit (E) assessments respectively. Since modelled energy consumption levels were not directly available in the tracking sheet, the participant EnerGuide ratings were used, which are based on modelled whole-home consumption. Also, if the final E assessment EnerGuide rating was not available, the projected final rating was used.
- AR corresponds to the adjustment ratio (AR) established through a billing analysis and used to adjust the savings obtained from the difference between the modelled electrical energy consumption during the D and E assessments. ARs vary according to different space heating system scenarios. ARs were drawn from billing analyses conducted in 2024 as part of the HEA evaluation.
- $\%Elec$ corresponds to the percentage of electrical space heating estimated by the DA through the D assessment.
- $Savings\ for\ Non\text{-}modelled\ Measures$ are obtained by multiplying the prescriptive measures installed through ASFH by their respective unitary electrical energy savings value.

After the D and E assessments, the EAs model the house in the HOT2000 energy simulation software to obtain the initial and final EnerGuide ratings of that house. These ratings were used to determine the electrical energy savings for modelled measures. ASFH modelled energy savings correspond to the reduction in energy consumption between the D and E assessments.

Since 2018, the methodology used to calculate tracked savings compared electrical D and E assessment space heating consumption levels, both of which being adjusted with an overestimation ratio (OR).

4.10.6.2 Coincident Peak Demand Savings (kW)

Value: 0.783

Source: This value was from tracked 2025 ASFH data for homes that only received building envelope upgrades.

Details: In practice, for measures modelled in HOT2000, peak demand savings are calculated by applying a peak demand-to-energy ratio of 0.283 MW/GWh after having removed the energy savings associated with mini-split heat pumps.

Table 52: Peak Demand-to-energy Ratios for Space Heating Measures

Measure	Peak Demand-to-energy Ratio (W/kWh)	Reference
Mini-split Heat Pumps (MSHPs)	-	-
Central Air-source Heat Pumps		
Ground-source Heat Pumps		
Wood and Pellet Stoves/Fireplace Inserts		
Wood and Pellet Furnaces/Boilers		
Solar Air Heating	0.000	Assumption
Air Sealing Products	0.283	RES-Elec-Space Heat & Cool, Navigant 2016-2018 DSM Plan
Programmable Thermostats	0.000	Assumption based on literature review findings
Smart Thermostats		
Modelled Space Heating and Building Envelope	0.283	RES-Elec-Space Heat & Cool, Navigant 2016-2018 DSM Plan

4.11 HW_HP_EI | HW HEAT PUMP - E1 INSTALLED

ASFH provides energy efficient retrofits and heat pump installations to income-qualified Nova Scotian owners of both electrically heated and non-electrically heated homes at no cost to participants. The program component is marketed under the HomeWarming brand and mainly provides building envelope measures such as draft-proofing and insulation for basements, crawl spaces, exposed floors, main walls, and attics. Heat pumps and smart thermostats are also offered under ASFH. Moisture management measures such as bathroom fans, dehumidifiers, and dirt floor coverings may also be provided. Retrofits are selected and implemented on a case-by-case basis.

HomeWarming has evolved to provide energy efficiency services for both electrically and non-electrically heated homes. Initially launched in 2012, HomeWarming focused on non-electrically heated homes through government funding, while ASFH, introduced in 2023, targets homes primarily heated with electricity using DSM-approved funding.

Starting on 1 January 2023, E1 assumed full responsibility for HomeWarming delivery, regardless of heating source, and introduced a heat pump only stream for past participants to apply for the new heat pump measure, excluding an energy assessment and additional building envelope upgrades.

ASFH is supported across Nova Scotia by seven delivery agents (DAs) and 43 heat pump contractors who conduct most of the field work. DAs use energy advisors (EAs) to perform pre-retrofit and post-retrofit energy assessments. Pre-retrofit assessments (D assessments) serve to examine the house, provide homeowners with a better understanding of how their house functions in relation to space heating, and identify applicable energy efficient upgrades to be implemented. EAs generate home energy assessment reports that provide a high-level overview of energy usage and send them to homeowners. DAs then recommend retrofits to E1 and complete those approved by the latter. Lastly, EAs conduct post-retrofit assessments (E assessments) to verify implemented measures and provide a final EnerGuide rating calculated using HOT2000, a simulation tool developed by Natural Resources Canada (NRCan). In the heat pump only stream, heat pump contractors conduct an initial home visit and make recommendations for the heat pump measure to E1. Once approved by E1, the heat pump contractor manages the installation of the heat pump and any electrical upgrades required to facilitate the installation.

ASFH participants are also eligible for the Efficient Product Installation (EPI) program component through which energy efficient products are installed at no cost to participants. ASFH participants are internally referred to EPI and generally participate in EPI before receiving a pre-retrofit energy assessment under ASFH.

HomeWarming participants who currently heat their homes with oil can also take advantage of funding available through the Oil to Heat Pump Affordability (OHPA) program to transition from oil systems to electric cold climate heat pumps if they meet OHPA program eligibility criteria (e.g., minimum annual oil usage). OHPA is a federal government program delivered through specific Efficiency Nova Scotia programs. Some ASFH participants who receive DSM support and have electric savings, may also be eligible for the OHPA program and participate in both (e.g., this can be seen when a home has electric and oil heating).

4.11.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	HW_HP_EI
Measure ID (Incremental Cost)	HW_HP_EI
Common Measure Name	HW Heat Pump - E1 Installed
Sector	Residential
Program Name	Existing Residential
Program Component	Affordable Single-Family Homes
Replacement Type	RET
Unit Basis	Per tonne
DI Flag	1

4.11.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below.

4.11.3 MEASURE LIFE

Value: 18 Years

Source: This value was drawn from Table 53[59] of the 2024 Residential DSM Measure Assessment.

[59] 2024-2025 DSM Measurement Assessment - Residential, Table 53: Mini-split Heat Pump Measure Summary, page 55 (PDF 72/159)

Table 53: Mini-split Heat Pump Measure Summary

Parameter	Green Heat, ASFH		HEA	MHEEP	Reference
Measure Description and Identification					
Measure	Mini-split heat pumps for high-efficiency space heating with direct installation (HEA, MHEEP) or rebated after purchase (Green Heat)				-
Baseline	Electric resistance space heating				
Application	Fully electrically heated households	Mainly electrically heated households	-		
General Parameters					
Installation Rate	100%				See details below under Installation Rates
Effective Useful Life [years]	18				See Subsection 3.2
Electrical Savings Parameters					
Unitary Energy Savings [kWh/year]	0.0855 kWh/Btu/h multiplied by the heating capacity of each installed system	0.000 kWh/Btu/h multiplied by the heating capacity of each installed system	Calculated using HOT2000 modelling with an adjustment ratio		See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	N/A				
Unitary Peak Demand Savings [W]	Calculation based on specification data for each installed system			0.148 W/Btu/h multiplied by the heating capacity of each installed system	See details below under Unitary Peak Demand Savings
Interactive Effects Factor for Energy Savings	0%				See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings	0%				See Subsection 2.3.1

4.11.4 NET TO GROSS

Value: 1.0

Source: For ASFH, free-ridership and spillover effects are considered to be nil since participants are non-profit organizations or low-income housing owners that traditionally have small housing budgets spread across many competing housing priorities. Therefore, a NTGR of 1.00 is applied.

4.11.5 DIRECT INSTALL COST

Value: 6,240.00 (in $2025)

Unit Basis: per project

Source: Per E1 program tracking.

Details: This value was derived from an analysis of 2024 program tracking data. The analysis was limited to HomeWarming heat pump-only projects (no building envelope upgrades) and found an average cost of approximately $6,000 per ton (in 2024 dollars). This value was then escalated to 2025 dollars.

4.11.6 SAVINGS

4.11.6.1 Energy Savings (kWh)

Value: 912

Source: The energy savings value currently tracked for mini-split heat pumps is based on Green Heat. The value was updated as part of this (2024) evaluation based on the billing analysis conducted for HEA. Treatment participants who only installed a mini-split heat pump through their participation in HEA were isolated to calculate an average energy savings value per capacity installed of 0.0760 kWh/Btu/h. See 2024 DSM Evaluation- Existing Residential Program, page 157 (PDF 183/229). Heat pump energy savings were assumed to be equivalent between HomeWarming and HEA.

Description	Value	Unit	Source
Energy Savings per Btu/h	0.076	kWh/Btu/H	pdf page 183/229
kW/ kWh Ratio	0.00159		Calculated from Table 21
Energy Savings per ton	912	kWh/Ton	Calculated
Peak demand savings per ton	1.449	kW/Ton	Calculated

Details: In practice, electrical energy savings are calculated based on HOT2000 simulation results adjusted with billing analysis results and unitary savings values for prescriptive measures, as shown in the equation below.

$$\begin{aligned} &Gross\ Energy\ Savings\ (kWh) \\ &= \left(\frac{\left(Total\ Energy_D(GJ) - Total\ Energy_E(GJ) \right)}{0.0036\ GJ/kWh} \times \%_{Elec} \right) \times AR \\ &+ Savings\ for\ Non\text{-}modelled\ Measures\ (kWh) \end{aligned}$$

Where:

- $Total\ EnergyD$ and $Total\ EnergyE$ correspond to the modelled energy consumption levels obtained in HOT2000 during the pre-retrofit (D) and post-retrofit (E) assessments respectively. Since modelled energy consumption levels were not directly available in the tracking sheet, the

participant EnerGuide ratings were used, which are based on modelled whole-home consumption. Also, if the final E assessment EnerGuide rating was not available, the projected final rating was used.

- AR corresponds to the adjustment ratio (AR) established through a billing analysis and used to adjust the savings obtained from the difference between the modelled electrical energy consumption during the D and E assessments. ARs vary according to different space heating system scenarios. ARs were drawn from billing analyses conducted in 2024 as part of the HEA evaluation.
- $\%Elec$ corresponds to the percentage of electrical space heating estimated by the DA through the D assessment.
- $Savings\ for\ Non\text{-}modelled\ Measures$ are obtained by multiplying the prescriptive measures installed through ASFH by their respective unitary electrical energy savings value.

After the D and E assessments, the EAs model the house in the HOT2000 energy simulation software to obtain the initial and final EnerGuide ratings of that house. These ratings were used to determine the electrical energy savings for modelled measures. ASFH modelled energy savings correspond to the reduction in energy consumption between the D and E assessments.

Since 2018, the methodology used to calculate tracked savings compared electrical D and E assessment space heating consumption levels, both of which being adjusted with an overestimation ratio (OR).

4.11.6.2 Coincident Peak Demand Savings (kW)

Value: 1.450

Source: This value was derived in part from 2024 evaluated non-modelled heat pumps in the HomeWarming program. See Table 22[60] of the 2024 Existing Residential Evaluation Report

[60] 2024-2025 DSM Measurement Assessment - Residential, Table 53: Mini-split Heat Pump Measure Summary, page 55 (PDF 72/159)

Table 22: Evaluated 2024 ASFH Gross Electrical Energy and Peak Demand Savings

Measure Category	Modelled Measures	Non-modelled Heat Pumps	Smart Thermostats	Appliance Replacements	Total
Number of Participants with Savings*	**880**	**254**	**79**	**-**	**1,193**
Energy Savings					
Gross Energy Savings – at the Meter (GWh)	**3.111**	**0.197**	**0.049**	**0.041**	**3.398**
Line Loss Factor	1.0947	1.0947	1.0947	1.0947	-
Gross Energy Savings – at the Generator (GWh)	**3.406**	**0.216**	**0.053**	**0.045**	**3.719**
Effective Useful Life (years)**	20.5	18.0	10.0	4.4	-
Gross Lifetime Energy Savings – at the Generator (GWh)	**69.817**	**3.883**	**0.531**	**0.197**	**74.428**
Peak Demand Savings					
Gross Peak Demand Savings – at the Meter (MW)	**1.501**	**0.313**	**-**	**0.007**	**1.822**
Line Loss Factor	1.1466	1.1466	1.1466	1.1466	-
Gross Peak Demand Savings – at the Generator (MW)	**1.722**	**0.359**	**-**	**0.008**	**2.089**

*The total number of participants does not correspond to the sum of all measure categories since participants who benefited from appliance replacements also implemented additional measures.

** Corresponds to the equivalent EUL obtained from dividing the non-modelled measure lifetime energy savings at the meter by the energy savings at the meter (see Table 21).

Details: This value was calculated by multiplying the peak demand-to-energy ratio by the unitary energy savings of 912 kWh.

Input	Description	Total
A	Gross Energy Savings at the Meter for Non-modelled Heat Pumps (GWh)	0.197
B	Gross Peak Demand Savings at the Meter for Non-modelled Heat Pumps (MW)	0.313
C = (B / A)/1000	Peak demand to energy ratio (kW/GWh)	0.00159
D = C*Energy Savings	Coincident Peak Demand Savings (kW)	1.450

4.12 IS_HVAC_HP | MINI-SPLIT HEAT PUMP

Instant Savings offers instant cash rebates to consumers who purchase eligible energy efficient products. Instant Savings is delivered with the help of one Delivery Agent (DA), Summerhill Group Inc., as well as national and independent retailers that offer instant rebates on energy efficient products at over 150 locations across Nova Scotia.

4.12.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	IS_HVAC_HP
Measure ID (Incremental Cost)	HEA_HVAC_HP
Common Measure Name	Mini-Split Heat Pump
Sector	Residential
Program Name	Residential Efficient Product Rebate
Program Component	Instant Savings
Replacement Type	RET
Unit Basis	Per unit
DI Flag	0

4.12.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below.

4.12.3 MEASURE LIFE

Value: 18 Years

Source: This value was drawn from Table 53[61] of the 2024 Residential DSM Measure Assessment.

[61] 2024-2025 DSM Measurement Assessment - Residential, Table 53: Mini-split Heat Pump Measure Summary, page 55 (PDF 72/159)

Table 53: Mini-split Heat Pump Measure Summary

Parameter	Green Heat, ASFH		HEA	MHEEP	Reference
Measure Description and Identification					
Measure	Mini-split heat pumps for high-efficiency space heating with direct installation (HEA, MHEEP) or rebated after purchase (Green Heat)				-
Baseline	Electric resistance space heating				
Application	Fully electrically heated households	Mainly electrically heated households	-		
General Parameters					
Installation Rate	100%				See details below under Installation Rates
Effective Useful Life [years]	18				See Subsection 3.2
Electrical Savings Parameters					
Unitary Energy Savings [kWh/year]	0.0855 kWh/Btu/h multiplied by the heating capacity of each installed system	0.000 kWh/Btu/h multiplied by the heating capacity of each installed system	Calculated using HOT2000 modelling with an adjustment ratio		See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	N/A				
Unitary Peak Demand Savings [W]	Calculation based on specification data for each installed system			0.148 W/Btu/h multiplied by the heating capacity of each installed system	See details below under Unitary Peak Demand Savings
Interactive Effects Factor for Energy Savings	0%				See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings	0%				See Subsection 2.3.1

4.12.4 NET TO GROSS

Value: 0.84

Source: Value drawn from the 2024 Existing Residential Evaluation, Net Savings, Table 64: 2024 HEA NTGR Values, page 162 (PDF 336/1442).

Table 64: 2024 HEA NTGR Values

Measure	Free-ridership	Participant Spillover	NTGR
Energy Efficiency Measures	17%	1%	0.84
Solar PV Measures	26%		0.75

4.12.5 INCREMENTAL COST

Value: $5,610.55 (in $2025)

Unit Basis: per project

Source: Per E1 program tracking.

Details: This value is an average cost per measure developed using recent tracked program delivery cost data.

4.12.6 SAVINGS

4.12.6.1 Energy Savings (kWh)

Value: 912

Source: The energy savings value currently tracked for mini-split heat pumps is based on Green Heat. The value was updated as part of this (2024) evaluation based on the billing analysis conducted for HEA. Treatment participants who only installed a mini-split heat pump through their participation in HEA were isolated to calculate an average energy savings value per capacity installed of 0.0760 kWh/Btu/h. See 2024 DSM Evaluation- Existing Residential Program, page 157 (PDF 183/229).

Description	Value	Unit	Source
Energy Savings per Btu/h	0.076	kWh/Btu/H	pdf page 183/229
kW/ kWh Ratio	0.00159		Calculated from Table 21
Energy Savings per ton	912	kWh/Ton	Calculated
Peak demand savings per ton	1.449	kW/Ton	Calculated

Details: This is a new measure; detailed savings methodologies will be determined alongside E1's evaluator and the measure continue to be delivered.

4.12.6.2 Coincident Peak Demand Savings (kW)

Value: 1.450

Source: This value was derived in part from 2024 evaluated non-modelled heat pumps in the HomeWarming program. See Table 22[62] of the 2024 Existing Residential Evaluation Report.

Table 22: Evaluated 2024 ASFH Gross Electrical Energy and Peak Demand Savings

Measure Category	Modelled Measures	Non-modelled Heat Pumps	Smart Thermostats	Appliance Replacements	Total
Number of Participants with Savings*	**880**	**254**	**79**	**-**	**1,193**
Energy Savings					
Gross Energy Savings – at the Meter (GWh)	**3.111**	**0.197**	**0.049**	**0.041**	**3.398**
Line Loss Factor	1.0947	1.0947	1.0947	1.0947	-
Gross Energy Savings – at the Generator (GWh)	**3.406**	**0.216**	**0.053**	**0.045**	**3.719**
Effective Useful Life (years)**	20.5	18.0	10.0	4.4	-
Gross Lifetime Energy Savings – at the Generator (GWh)	**69.817**	**3.883**	**0.531**	**0.197**	**74.428**
Peak Demand Savings					
Gross Peak Demand Savings – at the Meter (MW)	**1.501**	**0.313**	**-**	**0.007**	**1.822**
Line Loss Factor	1.1466	1.1466	1.1466	1.1466	-
Gross Peak Demand Savings – at the Generator (MW)	**1.722**	**0.359**	**-**	**0.008**	**2.089**

*The total number of participants does not correspond to the sum of all measure categories since participants who benefited from appliance replacements also implemented additional measures.

** Corresponds to the equivalent EUL obtained from dividing the non-modelled measure lifetime energy savings at the meter by the energy savings at the meter (see Table 21).

Details: This value was calculated by multiplying the peak demand-to-energy ratio by the unitary energy savings of 912 kWh.

Input	Description	Total
A	Gross Energy Savings at the Meter for Non-modelled Heat Pumps (GWh)	0.197
B	Gross Peak Demand Savings at the Meter for Non-modelled Heat Pumps (MW)	0.313
C = (B / A)/1000	Peak demand to energy ratio (kW/GWh)	0.00159
D = C*Energy Savings	Coincident Peak Demand Savings (kW)	1.450

[62] 2024-2025 DSM Measurement Assessment - Residential, Table 53: Mini-split Heat Pump Measure Summary, page 55 (PDF 72/159)

4.13 IS__HVAC_RAP_001__0 | ENERGY STAR CERTIFIED ROOM AIR PURIFIERS (RAP)

Instant Savings offers instant cash rebates to consumers who purchase eligible energy efficient products. Instant Savings is delivered with the help of one Delivery Agent (DA), Summerhill Group Inc., as well as national and independent retailers that offer instant rebates on energy efficient products at over 150 locations across Nova Scotia.

4.13.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	IS__HVAC_RAP_001__0
Measure ID (Incremental Cost)	IS__HVAC_RAP_001__0
Common Measure Name	Energy Star Certified Room Air Purifiers (RAP)
Sector	Residential
Program Name	Residential Efficient Product Rebates
Program Component	Instant Savings
Replacement Type	ROB/NEW
Unit Basis	Per unit
DI Flag	0

4.13.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below for details.

4.13.3 MEASURE LIFE

Value: 9 Years

Source: 2025 DSM Evaluation, Residential Efficient Product Rebates Program, Table 18, Page 28

4.13.4 NET TO GROSS

Value: 0.65

Source: 2025 DSM Evaluation, Residential Efficient Product Rebates Program, Table 22, Page 33

4.13.5 INCREMENTAL COST

Value: $114.13 (in 2025 dollars)

Unit Basis:

Source: Incremental cost was developed with the support of Apex Analytics

Details: Incremental costs for this measure were derived from several sources. Baseline material costs were sourced from web scraping and efficient unit costs from historical program data.

4.13.6 SAVINGS

4.13.6.1 Energy Savings (kWh)

Value: 768 kWh

Source: 2024-2025 Measure Assessment, 2024 Evaluation Edition - Residential - Table 108: Energy Star Certified Room Air Purifier Measure Summary, page 107

Details: In practice, the electrical energy savings value is determined by using the following equation for ENERGY STAR certified room air purifiers:

$$Energy\ Savings\left[\frac{kWh}{year}\right] = \left[CADR[cfm] \times \left(\frac{1}{EF_{base}} - \frac{1}{EF_{eff}}\right)\left[\frac{W}{cfm}\right] \times HOU\left[\frac{hours}{year}\right] + (SBP_{base} - SBP_{eff})[W] \times (8{,}760 - HOU)\left[\frac{hours}{year}\right]\right] \times \frac{1\ kW}{1{,}000\ W}$$

Values for this equation are pulled from the 10 most sold models under Instant Savings in 2024. Other values are based on the Savings Calculator for ENERGY STAR Qualified Appliances, as shown below.

Parameter	Symbol	Instant Savings	Reference
Clean Air Delivery Rate [cfm]	$CADR$	172	Weighted average of the 10 most sold models in the 2024 tracking sheet
Efficiency for Baseline Unit [cfm/W]	EF_{base}	1.00	Savings Calculator for ENERGY STAR Qualified Appliances[169]
Efficiency for Efficient Unit [cfm/W]	EF_{eff}	4.24	Weighted average of the 10 most sold models in the 2024 tracking sheet
Annual Operating Hours [hours/year]	HOU	5,840	Savings Calculator for ENERGY STAR Qualified Appliances
Standby Power for Baseline Unit [W]	SBP_{base}	1	Savings Calculator for ENERGY STAR Qualified Appliances
Standby Power for Efficient Unit [W]	SBP_{eff}	0.73	Weighted average of the 10 most sold models in the 2024 tracking sheet
Unitary Energy Savings [kWh/year]	$Energy\ Savings_{kWh}$	768	Calculation

4.13.6.2 Coincident Peak Demand Savings (kW)

Value: 0.13

Source: 2024-2025 Measure Assessment, 2024 Evaluation Edition - Residential - Table 108: Energy Star Certified Room Air Purifier Measure Summary, page 107

Details: Coincident peak demand savings are based on a peak demand-to-energy ratio of 0.171 W/kWh[63].

[63] 2024-2025 Measure Assessment, 2024 Evaluation Edition - Residential - Table 108: Energy Star Certified Room Air Purifier Measure Summary, page 107

4.14 IS__HVAC_TSTAT_001__0 | SMART THERMOSTATS FOR MINI-SPLIT HEAT PUMPS

Instant Savings offers instant cash rebates to consumers who purchase eligible energy efficient products. Instant Savings is delivered with the help of one Delivery Agent (DA), Summerhill Group Inc., as well as national and independent retailers that offer instant rebates on energy efficient products at over 150 locations across Nova Scotia.

Non-learning smart thermostats with programmable schedules through smart devices and additional sensor-based features (such as geofencing) that control electric baseboards, MSHPs, or electric in-floor heating for single-family homes and apartments as well as for central heating systems, namely central heat pumps or electric furnaces, for single-family homes.

4.14.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	IS__HVAC_TSTAT_001__0
Measure ID (Incremental Cost)	RES__HVAC_TSTAT_001__0
Common Measure Name	Smart thermostats for mini-split heat pumps
Sector	Residential
Program Name	Residential Efficient Product Rebates
Program Component	Instant Savings
Replacement Type	RET
Unit Basis	Per unit
DI Flag	0

4.14.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary sources of the values for measure input development are the Smart Thermostat for Electrical Heating Systems Measure from the 2024 program evaluation[64] and 2025 DSM Residential Measure Assessment[65]. The measure summary tables from this section are reproduced below.

[64] 2024 DSM Evaluation, Residential Efficient Product Rebates Program, Table 32: Evaluated 2024 Instant Savings Net Energy and Peak Demand Savings, page 40 (PDF 51/58)

[65] 2025 DSM Measure Assessment – Residential, Table 72: Non-learning Smart Thermostat for Electrical Heating System Measure Summary, page 70 (PDF 89/154)

Evaluated 2024 Instant Savings Net Energy and Peak Demand Savings (Continued)

Product Category	Smart Power Bars	Heavy-duty Outdoor Timers	Programmable Thermostats	Smart Thermostats			Clotheslines	Efficient Clothes Washers	Efficient Clothes Dryers
				EBB	MSHPs	In-floor Heating			
Energy Savings									
Gross Energy Savings – at the Meter (GWh)	**0.010**	**0.191**	**0.109**	**2.425**	**0.539**	**0.019**	**0.220**	**0.393**	**0.100**
NTGR	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Net Energy Savings – at the Meter (GWh)	**0.010**	**0.191**	**0.109**	**2.425**	**0.539**	**0.019**	**0.220**	**0.393**	**0.100**
Line Loss Factor	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947
Net Energy Savings – at the Generator (GWh)	**0.011**	**0.209**	**0.119**	**2.655**	**0.590**	**0.021**	**0.241**	**0.430**	**0.109**
Effective Useful Life (years)	4.0	10.0	10.0	10.0	10.0	10.0	10.0	11.0	12.0
Net Lifetime Energy Savings – at the Generator (GWh)	**0.044**	**2.090**	**1.188**	**26.548**	**5.902**	**0.212**	**2.407**	**4.731**	**1.313**
Peak Demand Savings									
Gross Peak Demand Savings – at the Meter (MW)	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.054**	**0.014**
NTGR	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Net Peak Demand Savings – at the Meter (MW)	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.054**	**0.014**
Line Loss Factor	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466
Net Peak Demand Savings – at the Generator (MW)	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.062**	**0.016**

Table 72: Non-learning Smart Thermostat for Electrical Heating System Measure Summary

Parameter	ASFH, Instant Savings		EPI						Reference
Measure Description and Identification									
Measure	Non-learning smart thermostats with programmable schedules through smart devices and additional sensor-based features (such as geofencing) that control electric baseboards, MSHPs, or electric in-floor heating for single-family homes and apartments as well as for central heating systems, namely central heat pumps or electric furnaces, for single-family homes								-
Baseline	Non-programmable thermostat								
Measure Subcategory	-		Single-family homes				Apartments		-
	Electric Baseboard or Electric In-floor Heating	MSHP	Electric Baseboard or Electric In-floor Heating	Electric Furnace	Central Heat Pump	MSHP	Electric Baseboard or Electric In-floor Heating	MSHP	
General Parameters									
Installation Rate	100%		100%			84%	100%	84%	See details below under Installation Rates
Effective Useful Life [years]	10								See Subsection 3.2
Electrical Savings Parameters									
Unitary Energy Savings [kWh/year]	265	479	265	1,725	959	479	205	455	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0								See Subsection 2.3.2
Unitary Peak Demand Savings [W]	0								Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%								See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings									

4.14.3 MEASURE LIFE

Value: 10 Years

Source: This value was drawn from Table 72 of the 2025 DSM Measure Assessment, shown above.

4.14.4 NET TO GROSS

Value: 1.0

Source: This value was drawn from Table 32 of the 2024 Existing Residential Evaluation.

4.14.5 INCREMENTAL INSTALL COST

Value: $182.67 (in $2025)

Unit Basis: per unit

Source: Incremental cost was developed with historical program data and the support of Apex Analytics

Details: Efficient material costs were sourced from historical program data and installation costs from contractor interviews

4.14.6 SAVINGS

4.14.6.1 Energy Savings (kWh)

Value: 479.0

Source: This is the deemed unitary energy savings value for the Smart Thermostat for Electrical Heating Systems Measure in the 2025 Measure Assessment, Table 72.

Details:

Some models of smart thermostats sold through Instant Savings or installed through EPI or MHEEP are compatible with electrical heating systems. They operate by connecting to a single baseboard, MSHP, or in-floor heating system as opposed to a central heating system. In practice, the equation below is used to calculate the unitary savings value for smart thermostats compatible with electrical heating systems and installed through Instant Savings, EPI or MHEEP.

$$Energy\ Savings_{kWh} = \frac{Heating\ Energy \times \%Savings}{FMT \times COP}$$

Since no studies specific to smart thermostats connected to electric baseboards, MSHPs, or electric in-floor heating systems were identified, the percentage of the heating load saved by thermostats is based on available studies for smart thermostats compatible with central heating systems, which have essentially the same features.

When searching for an appropriate value to assign as the heating consumption savings percentage, the Evaluator noticed that thermostats label as smart offer many different features that may impact the amount of savings generated by the measure. When combing through various TRMs and studies, the Evaluator identified three main categories of thermostats: Programmable thermostats, non-learning smart thermostats, and advanced learning thermostats. In summary, a programmable thermostat allows the user to program a schedule, the non-learning smart includes the programmable thermostat offer while enabling control through a smart device and additional features such as geofencing, and the advanced learning thermostat includes the non-learning smart thermostat offer and has use pattern learning capabilities. The value of 10.2% used for heating consumption savings is drawn from the 2025 Illinois TRM[66] because the Evaluator concluded that the efficient thermostat, as it was described in the corresponding algorithm, most resembled the non-learning smart thermostats installed or incented by E1.

As previously mentioned, electric baseboards, MSHPs, and electric in-floor heating systems are individually paired to a unique compatible smart thermostat. Therefore, the savings are divided by the average number of electrical heating systems within a dwelling and assuming there is one baseboard per room, one MSHP per floor, and one electric in-floor heating system per room.

4.14.6.2 Coincident Peak Demand Savings (kW)

Value: 0.000

Source: This is the deemed unitary peak demand savings value for the Smart Thermostat for Electrical Heating Systems Measure[67] in the 2025 Measure Assessment.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.000 – Assumption based on literature review findings).

[66] Illinois Commerce Commission, Illinois Statewide Technical Reference Manual for Energy Efficiency, Version 13.0 – Volume 3: Residential Measures, September 20, 2024, p. 220.

[67] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

4.15 IS__HVAC_TSTAT_002__0 | SMART THERMOSTATS FOR ELECTRIC BASEBOARDS

Instant Savings offers instant cash rebates to consumers who purchase eligible energy efficient products. Instant Savings is delivered with the help of one Delivery Agent (DA), Summerhill Group Inc., as well as national and independent retailers that offer instant rebates on energy efficient products at over 150 locations across Nova Scotia.

Non-learning smart thermostats with programmable schedules through smart devices and additional sensor-based features (such as geofencing) that control electric baseboards, MSHPs, or electric in-floor heating for single-family homes and apartments as well as for central heating systems, namely central heat pumps or electric furnaces, for single-family homes.

4.15.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	IS__HVAC_TSTAT_002__0
Measure ID (Incremental Cost)	IS__HVAC_TSTAT_002__0
Common Measure Name	Smart thermostats for electric baseboards
Sector	Residential
Program Name	Residential Efficient Product Rebates
Program Component	Instant Savings
Replacement Type	RET
Unit Basis	Per unit
DI Flag	0

4.15.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

The primary sources of the values for measure input development are the Smart Thermostat for Electrical Heating Systems Measure from the 2024 program evaluation[68] and 2025 DSM Residential Measure Assessment[69]. The measure summary tables from this section are reproduced below.

[68] 2024 DSM Evaluation, Residential Efficient Product Rebates Program, Table 32: Evaluated 2024 Instant Savings Net Energy and Peak Demand Savings, page 40 (PDF 51/58)

[69] 2025 DSM Measure Assessment – Residential, Table 72: Non-learning Smart Thermostat for Electrical Heating System Measure Summary, page 70 (PDF 89/154)

Evaluated 2024 Instant Savings Net Energy and Peak Demand Savings (Continued)

Product Category	Smart Power Bars	Heavy-duty Outdoor Timers	Programmable Thermostats	Smart Thermostats			Clotheslines	Efficient Clothes Washers	Efficient Clothes Dryers
				EBB	MSHPs	In-floor Heating			
Energy Savings									
Gross Energy Savings – at the Meter (GWh)	**0.010**	**0.191**	**0.109**	**2.425**	**0.539**	**0.019**	**0.220**	**0.393**	**0.100**
NTGR	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Net Energy Savings – at the Meter (GWh)	**0.010**	**0.191**	**0.109**	**2.425**	**0.539**	**0.019**	**0.220**	**0.393**	**0.100**
Line Loss Factor	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947	1.0947
Net Energy Savings – at the Generator (GWh)	**0.011**	**0.209**	**0.119**	**2.655**	**0.590**	**0.021**	**0.241**	**0.430**	**0.109**
Effective Useful Life (years)	4.0	10.0	10.0	10.0	10.0	10.0	10.0	11.0	12.0
Net Lifetime Energy Savings – at the Generator (GWh)	**0.044**	**2.090**	**1.188**	**26.548**	**5.902**	**0.212**	**2.407**	**4.731**	**1.313**
Peak Demand Savings									
Gross Peak Demand Savings – at the Meter (MW)	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.054**	**0.014**
NTGR	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Net Peak Demand Savings – at the Meter (MW)	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.054**	**0.014**
Line Loss Factor	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466	1.1466
Net Peak Demand Savings – at the Generator (MW)	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.062**	**0.016**

1

Table 72: Non-learning Smart Thermostat for Electrical Heating System Measure Summary

Parameter	ASFH, Instant Savings		EPI						Reference
Measure Description and Identification									
Measure	Non-learning smart thermostats with programmable schedules through smart devices and additional sensor-based features (such as geofencing) that control electric baseboards, MSHPs, or electric in-floor heating for single-family homes and apartments as well as for central heating systems, namely central heat pumps or electric furnaces, for single-family homes								-
Baseline	Non-programmable thermostat								
Measure Subcategory	-		Single-family homes				Apartments		-
	Electric Baseboard or Electric In-floor Heating	MSHP	Electric Baseboard or Electric In-floor Heating	Electric Furnace	Central Heat Pump	MSHP	Electric Baseboard or Electric In-floor Heating	MSHP	
General Parameters									
Installation Rate	100%		100%			84%	100%	84%	See details below under Installation Rates
Effective Useful Life [years]	10								See Subsection 3.2
Electrical Savings Parameters									
Unitary Energy Savings [kWh/year]	265	479	265	1,725	959	479	205	455	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0								See Subsection 2.3.2
Unitary Peak Demand Savings [W]	0								Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%								See Subsection 2.3.1
Interactive Effects Factor for Peak Demand Savings									

2

4.15.3 MEASURE LIFE

3

4 **Value:** 10 Years

5 **Source:** This value was drawn from Table 72 of the 2025 DSM Measure Assessment, shown above.

6

4.15.4 NET TO GROSS

Value: 1.0

Source: This value was drawn from Table 32 of the 2024 Existing Residential Evaluation.

4.15.5 INCREMENTAL INSTALL COST

Value: $189.63 (in $2025)

Unit Basis: per unit

Source: Incremental cost was developed with historical program data and the support of Apex Analytics

Details: Efficient material costs were sourced from historical program data and installation costs from contractor interviews

4.15.6 SAVINGS

4.15.6.1 Energy Savings (kWh)

Value: 265.0

Source: This is the deemed unitary energy savings value for the Smart Thermostat for Electrical Heating Systems Measure in the 2025 Measure Assessment, Table 72.

Details:

Some models of smart thermostats sold through Instant Savings or installed through EPI or MHEEP are compatible with electrical heating systems. They operate by connecting to a single baseboard, MSHP, or in-floor heating system as opposed to a central heating system. In practice, the equation below is used to calculate the unitary savings value for smart thermostats compatible with electrical heating systems and installed through Instant Savings, EPI or MHEEP.

$$Energy\ Savings_{kWh} = \frac{Heating\ Energy \times \%Savings}{FMT \times COP}$$

Since no studies specific to smart thermostats connected to electric baseboards, MSHPs, or electric in-floor heating systems were identified, the percentage of the heating load saved by thermostats is based on available studies for smart thermostats compatible with central heating systems, which have essentially the same features.

When searching for an appropriate value to assign as the heating consumption savings percentage, the Evaluator noticed that thermostats label as smart offer many different features that may impact the amount of savings generated by the measure. When combing through various TRMs and studies, the Evaluator identified three main categories of thermostats: Programmable thermostats, non-learning smart thermostats, and advanced learning thermostats. In summary, a programmable thermostat allows the user to program a schedule, the non-learning smart includes the programmable thermostat offer while enabling control through a smart device and additional features such as geofencing, and the advanced learning thermostat includes the non-learning smart thermostat offer and has use pattern learning capabilities. The value of 10.2% used for heating consumption savings is drawn from the 2025 Illinois TRM[70] because the Evaluator concluded that the efficient thermostat, as it was described in the corresponding algorithm, most resembled the non-learning smart thermostats installed or incented by E1.

As previously mentioned, electric baseboards, MSHPs, and electric in-floor heating systems are individually paired to a unique compatible smart thermostat. Therefore, the savings are divided by the average number of electrical heating systems within a dwelling and assuming there is one baseboard per room, one MSHP per floor, and one electric in-floor heating system per room.

4.15.6.2 Coincident Peak Demand Savings (kW)

Value: 0.000

Source: This is the deemed unitary peak demand savings value for the Smart Thermostat for Electrical Heating Systems Measure[71] in the 2025 Measure Assessment.

Details: In practice, unitary peak demand savings are calculated by multiplying the unitary savings value by the peak demand-to-energy ratio (0.000 – Assumption based on literature review findings).

[70] Illinois Commerce Commission, Illinois Statewide Technical Reference Manual for Energy Efficiency, Version 13.0 – Volume 3: Residential Measures, September 20, 2024, p. 220.

[71] 2024-2025 DSM Measure Assessment, Residential, Space Heating Measures, Smart Thermostats for Electrical Heating Systems, page 77 (PDF 1159/1442)

4.16 IS__OTH_TIMER_001__0 | OUTDOOR HEAVY DUTY TIMERS

Instant Savings offers instant cash rebates to consumers who purchase eligible energy efficient products. Instant Savings is delivered with the help of one Delivery Agent (DA), Summerhill Group Inc., as well as national and independent retailers that offer instant rebates on energy efficient products at over 150 locations across Nova Scotia.

4.16.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)	IS__OTH_TIMER_001__0
Measure ID (Incremental Cost)	IS__OTH_TIMER_001__0
Common Measure Name	Outdoor Heavy Duty Timers
Sector	Residential
Program Name	Residential Efficient Product Rebates
Program Component	Instant Savings
Replacement Type	ROB/NEW
Unit Basis	Pet Unit
DI Flag	0

4.16.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

See sections below for details.

4.16.3 MEASURE LIFE

Value: 10 Years

Source: 2024 DSM Residential Efficient Product Rebates Program Evaluation Report, Table 23, Page 31

4.16.4 NET TO GROSS

Value: 1.0

Source: 2024 Residential Efficient Product Rebates Program Evaluation, Instant Savings Impact Evaluation, Table 31: 2024 Instant Savings Net-to-gross Ratios, page 38

4.16.5 INCREMENTAL COST

Value: $18.63 (in 2025 dollars)

Unit Basis: per unit

Source: Per E1 program tracking.

Details: This value is the average cost per measure from recent tracked program data (2022-2023), escalated to 2025.

4.16.6 SAVINGS

4.16.6.1 Energy Savings (kWh)

Value: 122 kWh

Source: 2024-2025 DSM Measure Assessment, Residential, Plug Load Control Measures, Heavy-duty Outdoor Timers, page 118.

Details: For heavy-duty outdoor timers, the electrical unitary energy savings value of 122 kWh is based on the results of the OPA 2012 Consumer Program Evaluation. The survey conducted for that evaluation states that heavy-duty outdoor timers sold through the OPA biannual coupon program are used for outdoor lighting, pool pumps, and car block heaters, all of which correspond to possible usages for heavy-duty outdoor timers sold through Instant Savings.

Table 123: Heavy-duty Outdoor Timer Measure Summary

Parameter	Instant Savings	Reference
Measure Description and Identification		
Measure Description	Heavy-duty outdoor timers rebated in store	-
Baseline	Outdoor outlets without timers	
General Parameters		
Installation Rate	100%	See details below under Installation Rates
Effective Useful Life [years]	10	See Subsection 3.2
Electrical Savings Parameters		
Unitary Energy Savings [kWh/year]	122	See details below under Electrical Unitary Energy Savings
Peak Demand-to-energy Ratio [W/kWh]	0.000	See Subsection 2.5.2
Unitary Peak Demand Savings [W]	0.00	Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio
Interactive Effects Factor for Energy Savings	0%	See Subsection 2.5.1
Interactive Effects Factor for Peak Demand Savings	0%	See Subsection 2.5.1

4.16.6.2 Coincident Peak Demand Savings (kW)

Value: 0 kW

Source: 2024-2025 DSM Measure Assessment, Residential, Plug Load Control Measures, Heavy-duty Outdoor Timers, page 118.

Details: Calculated by multiplying the unitary savings value by the peak demand-to-energy ratio

5. APPENDIX A – BLANK MEASURE TEMPLATE

5.1 MEASURE ID | COMMON MEASURE NAME

Introductory text explaining the measure.

5.1.1 MEASURE IDENTIFIERS & DEFINING CHARACTERISTICS

Measure ID (Plan)
Measure ID (Incremental Cost)
Common Measure Name
Sector
Program Name
Program Component
Host Proxy
Replacement Type
Unit Basis
DI Flag

5.1.2 KEY SOURCES FOR MEASURE INPUT DEVELOPMENT

If one single source is used to derive multiple inputs, screenshots or other outputs may be included here for transparency.

5.1.3 MEASURE LIFE

Value: Years

Source:

5.1.4 NET TO GROSS

Value:

Source:

5.1.5 INCREMENTAL COST

Value: $

Source:

Details:

5.1.6 SAVINGS

5.1.6.1 Energy Savings (kWh)

Value: kWh

Source:

Details:

5.1.6.2 Coincident Peak Demand Savings (kW)

Value: kW

Source:

Details:

Request IR-39:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

(a) Regarding Section 2.2.2 "Residential Behaviour Program":

i) Pdf pg. 93 states: "In 2023, E1 collaborated with NS Power to address program overlap between E1's Residential Behaviour program component and NS Power's Customer Energy Management program."

- **Please explain whether E1 has a program development strategy or process to avoid potential conflicts with the programs already introduced by NS Power or other similar entities.**
- **Please explain whether, and if so how, E1 communicated with NS Power about the Residential Behaviour program during planning stage**.

(b) Regarding Section 3.2.1 "Resource Scenario Design":

i) Pdf pg. 104 states: "Accordingly, energy savings in the 2027–2031 Preferred Plan, as a percentage of load, are 0.8 percent of NS Power's load forecast."

- **Please explain how E1 allocates the 0.8 percent of NS Power load saving across different rate classes when developing Preferred Plans and the rationale for this allocation approach.**

(c) Regarding Section 4.4 "Portfolio Savings and Investment:

i) In comparing Table 7 on pdf pg. 115 of the application to Table 8 from Appendix A of E1's 2023-2025 DSM application (M10374, pdf pg. 137), Board staff notes that annual spending is increasing in the proposed 2027-2031 DSM plan compared to the 2023-2025 DSM plan, but energy savings and peak demand savings are

decreasing. In this context, when does E1 expect that further DSM spending will no longer be economic? Please explain.

(d) Pdf pg. 123 states: "Investment levels in Residential sector programs represent approximately 56 percent of the energy efficiency portfolio and BNI sector programs at 44 percent. At the same time, residential sector programs will generate approximately 29 percent of the portfolio savings and BNI sector programs providing 71 percent of the energy efficiency portfolio savings." In this context, please explain why E1 has not opted for more energy efficiency investment in the BNI sector and less investment in the Residential sector.

(e) With regards to proposed Rate Class Coat Allocations: pdf pg. 128 states: "Planned rate class savings and expenditures for the 2027–2031 DSM Preferred Plan are provided in Table 15, below. E1 has also provided rate class expenditures and savings by program in Attachment 2."

i) Please provide a reference in the evidence filed to date showing where the numbers in Table 15 have been calculated.

- **If no such supporting calculations have been filed to date, please provide the calculations in spreadsheet format with all formulae intact and unaltered.**

ii) Please provide a reference in the evidence filed to date showing where the numbers in Attachment 2 have been calculated.

- **If no such supporting calculations have been filed to date, please provide the calculations in spreadsheet format with all formulae intact and unaltered.**

(f) Board staff notes that Table 17 of Appendix A of Exhibit E-1 (pdf pg. 135), shows proposed annual investment for the Residential Instant Savings Component ranging from $2.2M to $5.2M from 2027 to 2031, for a total investment of $20.6M over this period. However, Appendix A, Attachment 3 shows total annual PAC costs for the Instant Savings Program ranging from $1.2M to $4.0M for each year for the 2027-2031 DSM plan. Please explain and reconcile Table 17 with Appendix A, Attachment 3.

i) If required, please recalculate the Attachment 3 annual PAC score and payback period for each measure in the Residential Instant Savings program for each year from 2027 to 2031, and provide a revised Appendix A, Attachment 3 in Excel format with all formulae intact and unaltered.

(g) Board staff notes that that the same comment as noted in f. above for the Residential Instant Savings Program also applies to Appendix A Tables 20, 21, 22, 23, 24, 29, 32, 36, 37 and 41 in that annual investment for the related programs for 2027-2031 shown in the Tables appears to differ from the total annual investment amounts shown in Appendix A, Attachment 3. Please explain and reconcile the Tables with Appendix A, Attachment 3.

i) If required, please recalculate the Attachment 3 annual PAC score and payback period for each measure within each program for each year from 2027 to 2031, and provide a revised Appendix A, Attachment 3 in Excel format with all formulae intact and unaltered.

ii) Board Staff notes that the "Incentives only" PAC scores in Appendix A Attachment 3 appear to pass the PAC test for all programs, while Tables 9 to 13 in Appendix A of Exhibit E-1 (pdf pgs. 117-121) show that some programs fail the PAC test. For the programs that fail the PAC test in Appendix A of Exhibit E-1 (pdf pgs. 117-121), has E1 considered reducing "non-incentive" related costs to the extent that the program would pass the PAC test? Please explain.

- **For the programs that fail the PAC test in Appendix A of Exhibit E-1 (pdf pgs. 117-121), please identify the reduction in "non-incentive" related costs that would be required for the program to pass the PAC test.**

(h) Table 21, Pdf pg. 141 states: "…heat pumps including no-cost heat pump cleanings (heat pump cleanings new for 2027–2031)".

i) Please provide additional details about the heat pump cleaning program.

ii) Please explain the rational for including heat pump cleanings as a DSM measure, including how the measure could eventually pass the cost benefit analysis test.

Response IR-39:

(a)

i)

- E1 holds the exclusive franchise for demand-side management activities in Nova Scotia pursuant to Section 79C of the Public Utilities Act, RSNS 1989, c 380. By operation of that franchise, no other entity - including NS Power or other similar organizations - may provide electricity demand-side management programs within the scope of E1's franchise without contravening the franchise regime established under Part 79C of the Act. E1's program development process is accordingly structured on the premise that it is the sole authorized provider of such programs. For the Residential Behaviour program specifically, E1 worked with NS Power to set up its Residential Behaviour program through a separate module on NS Power's Customer Energy Management System, which benefited both

organizations. E1 also works collaboratively with NS Power on the delivery of E1's demand response programs.

- During a DSM Plan development, E1 works closely with the Demand Side Management Advisory Group, of which NS Power is a member.

(b) E1 does not design the DSM Plan by rate class. Rather, the program component costs and savings in the DSM Plan are allocated to individual rate classes with the sum of the program components providing the total rate class spending and savings. For the rate class allocation methodology please refer to E1's response to IG IR-16.

i) Please refer to E1's response to part (b)

- Please refer to E1's response to part (b).

(c) Cost effectiveness is assessed using the Program Administrator Cost (PAC) test under the Board-approved Standardized Filing Framework, which compares the present value of program benefits to the present value of costs. A DSM Plan is cost effective, and therefore economical, where benefits are equal to or greater than costs - meaning DSM investment is less expensive than the supply-side resources that would otherwise be required. E1 must demonstrate cost effectiveness for each DSM Plan filed with the Nova Scotia Energy Board.

Whether DSM investment remains economical is a question determined on a plan-cycle basis and will depend on a number of factors prevailing at the time, including: (i) the then-current cost of supply-side options against which DSM is benchmarked; and (ii) NS Power's Integrated Resource Plan as it exists from time to time. Additional factors include avoided cost assumptions, program delivery costs, and market conditions. E1 has not predetermined a point at which DSM will no longer be economical; that assessment will be made through the evidence filed in each future plan cycle, subject to Board review.

i) Please see part (a) to this IR response.

(d) The higher per-unit cost of Residential sector programs reflects the structure of that customer base, not an inefficient allocation of resources. Residential customers represent approximately 519,000 customers, or 91 percent of NS Power's total customer base. The Board-approved Standardized Filing Framework requires E1 to adhere to Balanced Plan Principles, which include diversity of program delivery and equitable access to programs across all market sectors and rate classes. E1 addresses barriers to participation for all customer groups, including dedicated low-income and equity programs such as Affordable Single-family Homes, Affordable Multifamily Housing, the Mi'kmaw Home Energy Efficiency Project, and Mi'kmaw New Construction. These programs necessarily carry higher per-participant delivery costs due to the nature of the customer support required.

The comparison between Residential investment (56 percent) and Residential savings (29 percent) reflects a per-unit cost differential that is inherent to program design - not a misallocation. BNI customers achieve greater savings per dollar invested because individual BNI projects involve larger loads and lower per-unit delivery costs. Simply shifting investment from Residential to BNI would not eliminate Residential customers' need for DSM programs, nor would it align with the Balanced Plan Principles, which E1 considers representing best practices in equitable and effective DSM program design. E1 does not agree that the current allocation is economically unjustified or that reallocation to the BNI sector would produce a more appropriate DSM Plan.

(e) Please refer to Attachment 1 of E1's response to IG IR-21.

i) Please refer to Attachment 1 of E1's response to IG IR-21.

- Please refer to Attachment 1 of E1's response to IG IR-21.

ii) Please refer to Attachment 1 of E1's response to IG IR-21.

- Please refer to Attachment 1 of E1's response to IG IR-21.

(f) E1 confirms that the investment in Appendix A, Table 17 is correct. Please refer to Attachment 1 of E1's response to NSEB IR-38.

(i) Please refer to E1's response to part (f).

(g) E1 confirms that investment in Appendix A, Tables 20, 21, 22, 23, 24, 29, 32, 36, 37, and 41 is correct. Please refer to Attachment 3 of E1's response to NSEB IR-16.

i) Please refer to E1's response to part (g).

ii) The program components referred to that did not pass the cost effectiveness test are dedicated low-income and equity programs that are either fully funded such as Affordable Single-family Homes and Mi'kmaw Home Energy Efficiency Project or receive higher incentives such as Mi'kmaw New Home Construction. Prior to filing E1's DSM Plan, E1 did assess all non-incentive costs for programs that did not pass the cost effectiveness test. Access to these dedicated low-income and equity programs does require E1 to provide additional or very specific support for customers. Reducing this support would create barriers for both low-income customers and customers in the Mi'kmaw communities.

- Please refer to E1's response to part (g).

(h) Please refer to E1's response to NS Power IR-14.

i) Please refer to part (h).

ii) Please refer to part (h).

Request IR-40:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, page 19 of 112 (pdf pg. 107):

E1 notes that, for existing measures, measure-level inputs were developed using the most recently available program and evaluation data, but some inputs were modified to reflect know or expected differences over the 2027-2031 period. Please identify the inputs that were modified, the known or expected differences that warranted the modifications, and how the precise modification was determined.

Response IR-40:

For existing measures, E1 developed measure-level inputs using the most recent available program tracking and evaluation data and modified these inputs where appropriate to reflect known or expected changes over the 2027–2031 DSM Plan period.

Modified inputs include energy and peak demand savings, effective useful life (EUL), net-to-gross ratios, measure costs, and participation assumptions.

Modifications reflect updated evaluation findings, observed program experience, market code developments, and planned program design changes. Examples include:

- Lighting measures: updated baselines and adoption of a dual baseline approach reflecting LED market transformation, reducing effective useful life.
- Heat pump measures: revised savings assumptions using adjustment ratios derived from billing analysis to better reflect realized savings across different participant conditions.

- Custom New Construction: adjustments to baselines to reflect anticipated adoption of more stringent building code requirements throughout the Plan (National Energy Code of Canada for Buildings tiers), reducing incremental savings over time.

Modifications were determined through application of evaluation results, analysis of recent program data, consultant input, and professional judgement. Where future changes were known or expected, these were incorporated through staged or time-dependent adjustments. All inputs were subject to iterative review to ensure they reflect current and expected conditions.

Request IR-41:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Appendix A, page 92 of 112 (pdf pg.180), Table 54: 2027-2031 Outreach Activities:

(a) E1 notes that continual improvement of the tools and content on its website and social media platforms is critical for educating and engaging with Nova Scotians. Please explain how the tools and content are measured to determine whether changes are improvements.

(b) What is a "total awareness score"?

(c) E1 notes that one of its measures of success is that its preferred partner membership remains steady or grows. Given that there were 451 members in its preferred partner network at the end of 2025 [Exhibit E-2, page 41 of 47], please explain why it is a measure of success that it perpetually grows its preferred partner membership. Has E1 done any analysis to assess the optimal number of preferred partners and the point at which further investment in growing the number of preferred partners results in diminished returns? If so, please provide this analysis.

Response IR-41:

(a) EfficiencyOne (E1) has a robust monthly measurement report that tracks website performance, which includes individual tools and content. Measurements include but are not limited to number of users, engagement rates and time spent highlighting where there may be fluctuations in performance, leading to deeper analysis on potential key drivers.

Due to the historical tracking, E1 is able to baseline performance ahead of any improvements being deployed and results are analyzed monthly to ensure improvements are resulting in the desired objective and to identify any necessary optimizations required.

(b) 'Total awareness score' is tracked as part of Narrative Research's Atlantic Quarterly omnibus research that asks Nova Scotians questions covering a number of topics and companies can commission specific research questions. E1 has commissioned questions related to Awareness & Opinion of Efficiency Nova Scotia (ENS) and E1 including the following: 'To the best of your knowledge, what is the name of the organization that helps Nova Scotians reduce their energy use?/Prior to today, had you ever heard of Efficiency Nova Scotia, the organization that helps Nova Scotians reduce their energy use.' The total awareness score is the percent of respondents that answer 'yes' to these questions.

(c) One of the measures of success for the Efficiency Preferred Partner network is to remain steady or grow. The growth measure is to account for the addition of new businesses from diverse communities to ensure equitable support and access across Nova Scotia and to provide flexibility to increase enrollment in specific sectors as program requirements, demand and technologies evolve.

E1 has benchmarked the existing membership against Dunn and Bradstreet Company Registration database to understand market size. Currently, the Efficiency Preferred Partner network represents approximately 15% of total relevant Standard Industrial Classification (SIC) codes in Nova Scotia. E1 is currently working on a deeper analysis of potential gaps by SIC which will inform areas of opportunity based on existing programs and potential demand driven by the DSM recommendations but it is anticipated that as programs and technology evolve, this will be an ongoing exercise to ensure balanced enrollments/membership by SIC and investment in the network.

Request IR-42:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, page 99 of 112 (pdf pg.187), Table 62: 2027-2031 DSM Preferred Plan Performance Indicators:

(a) For each performance indicator identified, please discuss why the indicator should not be developed as a performance target.

Response IR-42:

EfficiencyOne (E1) submits that Performance Targets must be directly linked to E1's statutory mandate as the franchise holder under the Public Utilities Act ("PUA"). Pursuant to section 79C(2)(a) of the PUA, E1 holds the exclusive right to supply Nova Scotia Power Inc. ("NS Power") with "reasonably available, cost-effective demand-side management." The Nova Scotia Energy Board ("NSEB") confirmed in its 2025 Benefit-Cost Analysis Decision (M12282, para. 128) that "the purpose of the demand-side management provisions in the Public Utilities Act is to reduce electricity costs for customers."[1] Performance Targets must therefore reflect the core outcomes through which the NSEB can determine whether E1 has fulfilled this legislative purpose. The five currently proposed Performance Targets - First Year Energy Savings, Peak Demand Savings, Dedicated Low-Income and Equity Energy Savings, Available Demand Response Capacity, and Solar PV Generation - each map directly to a defined element of the DSM mandate under section 79A(b) of the PUA and to the activities E1 is exclusively authorized to deliver under its Franchise. These Targets are independently evaluated by the NSEB's savings verification consultant,

[1] M12282, NSEB Decision, E1 application for approval of a New Benefit-Cost Analysis Test for Evaluating Demand Sid Management Plans, December 10, 2025.

providing the NSEB with an objective, independently verified basis on which to assess E1's compliance with its mandate. E1 respectfully submits that the proposed Performance Targets represent the appropriate exercise of the NSEB's oversight authority, proportionately calibrated to E1's legislated functions.

E1 agrees that Performance Indicators provide supplemental information that assists the NSEB in monitoring E1's delivery of the DSM Plan. However, E1 respectfully submits that Performance Indicators should not be elevated to Performance Targets. E1's annual DSM investment of $63.75 million represents approximately 3.3 percent of the approximately $1.9 billion in total annual electricity expenditures paid by Nova Scotians in 2025. E1 submits that performance requirements should be proportionate to its scale and mandate. The five proposed Performance Targets, each tied directly to a core deliverable of the Preferred Plan and independently evaluated, already provide the NSEB with objective oversight. Elevating supplemental indicators to formal Performance Targets would impose compliance and monitoring obligations, resulting in increased costs to NS Power ratepayers, without meaningfully improving the Board's ability to assess E1's fulfillment of its legislative mandate.

Request IR-43:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, page 103 of 112 (pdf pg. 191):

E1 notes that the demand response program evaluation is aimed at verifying and quantifying the available capacity to the utility over the winter peak period, which differs from peak demand savings.

(a) Given the importance of peak demand savings, please explain why the program's actual reduction of peak demand should not be assessed, notwithstanding that E1 does not control the calling of demand response events.

Response IR-43:

(a) Energy efficiency measures installed permanently achieve both energy savings and peak demand savings. For example, the installation of a mini-split heat pump to offset electric baseboard space heating reduces energy use throughout the entire year, resulting in energy savings, and reduces peak demand during the utility peak period. NS Power's utility peak period is defined as December to February on non-holiday weekdays between 5:00 and 7:00 p.m. Accordingly, both energy savings and peak demand savings are evaluated as performance metrics for EfficiencyOne's (E1) energy efficiency programs.

Demand response differs fundamentally from energy efficiency in that it seeks to reduce load during peak times through a temporary, signal-driven change in load (e.g., price signal, event, dispatch). Unlike energy efficiency measures, demand response does not produce

an ongoing reduction in peak demand (system peak), and its load impact is contingent on when events are called by the utility.

This distinction is reflected in the NS Power 2026 Load Forecast, which presents two peak measures:

- **System peak** – represents total demand, including interruptible load and demand response load. Energy efficiency load reductions are reflected in system peak.
- **Firm peak** – calculated as system peak minus interruptible load and demand response, recognizing these as resources that can be curtailed when required.

As stated in NS Power's 2026 Load Forecast report, "Like the interruptible load, DR programs are a resource that can be called upon if required, but they will likely not inherently reduce demand. In recognition of this, peak reduction from DR is included in the firm peak but is excluded from the system peak."[1]

Given this structure, E1's current performance metric for its demand response program is Available Demand Response Capacity, defined as the total DR capacity made available during the evaluated period - specifically, the load reduction made available by participating devices during the events called within the DR season. This metric reflects what E1 can directly influence: enrolling participants, ensuring device readiness, and making capacity available to NS Power when events are called.

The actual reduction of peak demand at the utility peak period depends on NS Power's decision to call events, which E1 does not control. Evaluating E1's program performance against actual peak demand reduction would conflate E1's program delivery responsibilities

[1] M12861, NS Power 2026 Load Forecast Report, May 15, 2026, page 95 of 105, lines 9-12.

with NS Power's system operations and dispatch decisions. Available Demand Response Capacity is therefore the appropriate metric for assessing E1's DR program performance. Please also refer to E1's response to part (a) of Synapse IR-70 for further detail.

Request IR-44:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, page 108 of 112 (pdf pg. 196):

E1 discusses enhancements it agreed to make in the 2026 DSM Extension matter.

(a) Should estimation accuracy be established as a performance target? If not, why not?

(b) Should variances in program spending against the DSM plan be established as a performance target? If not, why not?

(c) How does enhanced reporting address the concerns raised by Industrial Group if they do not have an opportunity to dispute a mid-course adjustment that E1 intends to make?

Response IR-44:

(a) EfficiencyOne (E1) does not agree that estimation accuracy or program spending variances should be established as standalone performance targets. Establishing such targets could constrain E1's ability to respond to evolving market conditions, customer uptake, and program performance data, thereby undermining E1's ability to achieve the core Nova Scotia Energy Board (NSEB) approved performance targets, including: (i) incremental cumulative net energy savings and cumulative peak demand savings from energy efficiency; (ii) incremental cumulative net energy savings from dedicated low-income and equity programs; (iii) available capacity from demand response; and (iv) energy reductions from customer-sited solar-PV generation. E1's DSM Plan is designed around outcomes-

based accountability. Imposing input-level metrics such as estimation accuracy or spending variances as binding performance targets would shift the regulatory framework toward a prescriptive, compliance-oriented model, inconsistent with the flexibility required to deliver cost-effective demand-side management (and ultimately achieve the Board established existing Performance Target metrics). E1's proposed mid-course adjustment process is designed to provide structured, transparent accountability for material deviations while preserving E1's ability to optimize program delivery, which is ultimately, in the best interest of ratepayers.

(b) Please refer to E1’s response to part (a).

(c) E1's enhanced reporting framework addresses the Industrial Group's concerns by providing advance notice of any material proposed mid-course adjustment to the NSEB and intervenors, including the rationale for the adjustment and its expected impact on program performance and spending. The NSEB retains ongoing oversight jurisdiction and may direct a review process if warranted. A formal dispute mechanism for each adjustment is not required and would impose unnecessary regulatory delay inconsistent with effective DSM portfolio management. Please also refer to E1’s response to NSEB IR-30.

Request IR-45:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, page 108 of 112 (pdf pg. 196):

E1 discusses further mid-course adjustment enhancements it proposes, including reducing thresholds for requiring explanations for program spending and savings and rate class spending.

(a) Should E1 be required to seek Board approval for changes exceeding these thresholds rather than simply providing explanations for doing so?

Response IR-45:

(a) Please refer to EfficiencyOne's response to NSEB IR-30.

Request IR-46:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Regarding Appendix A, Attachment 1: worksheet PAC Assumptions:

(a) Do the costs provided by NS Power for energy, capacity, transmission and distribution align with the recently approved Cost of Service Study approved by the Board in NS Power's General Rate Application M12451?

(b) Have the Program Administration cost profiles from the last four years, 2021-2024 been adjusted to account for inflation?

(c) Will NS Power's weighted average cost of capital be updated annually?

Response IR-46:

(a) EfficiencyOne (E1) is not aware of any required updates to avoided costs based on the recently approved General Rate Application.

(b) The program administration costs as modelled in the 2027–2031 DSM Plan are informed by inflation rates.

(c) E1 understands that NS Power files an updated weighted average cost of capital (WACC) Application annually with the Nova Scotia Energy Board in years in which it does not update its WACC rate through a General Rate Application. The most recent NS Power WACC will be

used as the discount rate for the Program Administrator Cost (PAC) test applied to future DSM Plans.

E1 does not revise the discount rate when calculating annual PAC results for actual performance, as the intent of these results is to compare actual outcomes against the approved DSM Plan. Keeping the discount rate unchanged best supports a consistent and meaningful comparison with the Plan.

Request IR-47:

<u>Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)</u>

Regarding Appendix A, Attachment 1: worksheet AVC Energy Seasonal:

(a) Please explain the source for the values 467,024 and 2,265 used to estimate levelized AVE Energy under Table 1.

i) Why do all the estimates under each table not match the values in the table?

ii) Why does the table for levelized costs use the NPV of annual avoided energy costs and the NPV of Nominal WACC?

(b) Why are there no values in Table 1, Table 2 or Table 3 for Real WACC?

(c) Please explain the values under Nominal WACC and how they are estimated.

(d) Please explain why WACC is used to estimate the change to energy.

Response IR-47:

The following IR responses were provided by NS Power.

(a)

i) This is an error. The values in the graphic should reflect the numbers in the table. Please find attached an updated version of the spreadsheet (Attachment 1 of this IR response).

ii) The method used to calculate the avoided costs is based on the widely accepted method, used in the electricity industry, for calculating the levelized cost of energy. The levelized cost of energy is calculated by taking the net present value of the total cost of building and operating a power generating asset and dividing it by the net present value of the total electricity generated over its lifetime.

(b) The column titled "Real WACC" is not populated as the heading exists solely to identify the discount rate used in the Energy Net Present Value (NPV) calculation in the bottom row of the table. The actual avoided energy does not vary between the Nominal and Real WACC columns, only the discount rate used in the NPV calculation varies.

(c) The values under nominal WACC are calculated by subtracting the annual energy requirement of the system inclusive of DSM impacts (i.e. the Base Case) from the annual energy requirement of a theoretical system absent any DSM programming (i.e. No DSM Case). Please note the annual values are energy amounts and the heading title "Nominal WACC" only indicated the discount rate used to calculate the Net Present Value in the bottom row of the column.

(d) Inflation is based on a publicly available forecast for inflation (CPI) which is, on average, 2% annually. The real WACC is the nominal WACC adjusted for inflation.

(e) Please see the response to part (b)(ii).

Request IR-48:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Regarding Appendix A, Attachment 1: worksheet AVC Energy & Capacity: please describe how the Capacity Adjustment for Planning Reserve Margin was derived.

Response IR-48:

The following IR response has been provided by NS Power.

The 9 percent Planning Reserve Margin (PRM) is the unforced capacity (UCAP) PRM necessary to maintain a resource adequacy target of no more than 1 loss of load event in 10 years in Nova Scotia, as determine by Energy and Environmental Economics, Inc. (E3) in the 2019 Planning Reserve Margin and Capacity Value Study. This value was used in the 2020 Integrated Resource Plan (IRP), 2023 Evergreen IRP, and subsequent updates to the avoided costs of energy and capacity.

The Capacity Adjustment for Planning Reserve Margin was derived by taking the levelized avoided cost of capacity and applying the planning reserve margin required to maintain resource adequacy. Since the avoided cost of capacity is associated with a reduction in peak load, this approach assumes that any cost of capacity avoided will also result in the relative avoided costs for planning reserve margin (PRM). Applying the PRM of 9 percent to the avoided capacity cost represents the avoided PRM.

Request IR-49:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Reference Appendix A, Attachment 3 (Exhibit E-1-(ii)):

E1 provides justification for measures that do not pass the program administrator cost (PAC) test.

(a) If ongoing support is required to maintain heat pumps, please indicate whether ongoing maintenance costs were included in E1's cost benefit assessments for heat pump measures when they were originally approved. If not, please explain in detail why not.

(b) Please quantify the degradation in E1's investment in heat pumps if heat pump cleanings for past participants is not provided.

(c) The "IR-Griddle-Electric" measure shows an overall PAC result of 0.62 for the plan, and PAC results ranging from 0.53 to 0.68 between 2027 and 2031. Please explain the following statement in the justification for this measure: "In fact, the application rebates variation is on the cusp of passing PAC in 2027 and 2028, and passes from 2029 and 2031."

(d) The "Solar Security Fixture", "Outdoor Motion Sensor" and "Indoor Motion Sensor" measures appear to cost 5-10 times more than the benefits provided. Please provide a more comprehensive justification for including these measures, and discuss in detail how providing measures that cost so much more than the benefits they provide are necessary to maintain delivery costs and keep contractors engaged as alleged in the justification provided in Appendix A-3.

Response IR-49:

(a) The primary cost-effectiveness test applied at the portfolio level is the Program Administrator Cost (PAC) test, as directed by the Nova Scotia Energy Board (NSEB) in its Decision in M12282.[1] This PAC test takes the perspective of the utility and includes only utility costs and benefits. As such ongoing maintenance costs for customers (host customer costs) in relation to heat pumps are not included in the PAC test. Only those DSM program administrator costs being borne by electric ratepayers are included as costs in the PAC. In the case of the proposed heat pump cleaning measure included in E1's proposed 2027–2031 DSM Preferred Plan, the DSM investment is included in the PAC for this measure.

(b) EfficiencyOne (E1) has not explicitly modelled performance degradation of heat pumps over time in its savings assumptions. First-year savings are based on billing analysis and modelling (HOT2000), which reflect typical in-field performance but do not include a defined degradation factor. The heat pump cleaning measure is intended to maintain system performance and support persistence of savings for those customers where barriers exist to maintain the system, rather than recover a specifically quantified degradation value within the current modelling framework.

(c) Please refer to E1's response to NSEB IR-04 part (c).

(d) The Efficient Product Installation program component delivers no-cost direct installations to homeowners and renters. Solar security fixtures, outdoor motion sensors, and indoor motion sensors are anticipated to possess higher unit costs but only be installed in 10

[1] M12282, NSEB Decision, E1 application for approval of a New Benefit-Cost Analysis Test for Evaluating Demand Side Management Plans, December 10, 2025.

percent of participating homes. The program still passes the PAC test with a ratio of 1.0 over the duration of the Preferred Plan.

Less cost-effective measures are included to diversify the program component offering and capitalize on all opportunities within a home during a single visit. Some participants may only be interested in particular products but the program component can increase uptake of others and total home savings by bundling them. Service Providers have an opportunity when in the home to assess installation opportunities and suitability, as well as educate and discuss options with customers to encourage them to accept more products.

E1 regularly assesses different products with Service Providers to balance the offering and ensure the program remains cost-effective. If less cost-effective products were removed without viable alternatives, it would shrink the total number of available products and increase the risk of Service Providers not engaging with the program or increasing their program administration and travel charges to ensure home visits remain worthwhile. E1 has received this feedback directly from Service Providers since starting to deliver these services in late 2024.

Request IR-50:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Regarding Appendix A, Attachment 5 of Exhibit E-1 – "Innovation Framework, Process and Plan for 2027-2031":

(a) Pdf pg. 21 of the application: "E1 engaged with the DSMAG throughout the development of these plans and is filing the Innovation Framework, Process and Plan for 2027–2031 as part of this Application in Appendix A, Attachment 5." Provide any feedback/comments for DSMAG parties about the Framework, Process and Plan for 2027-2031.

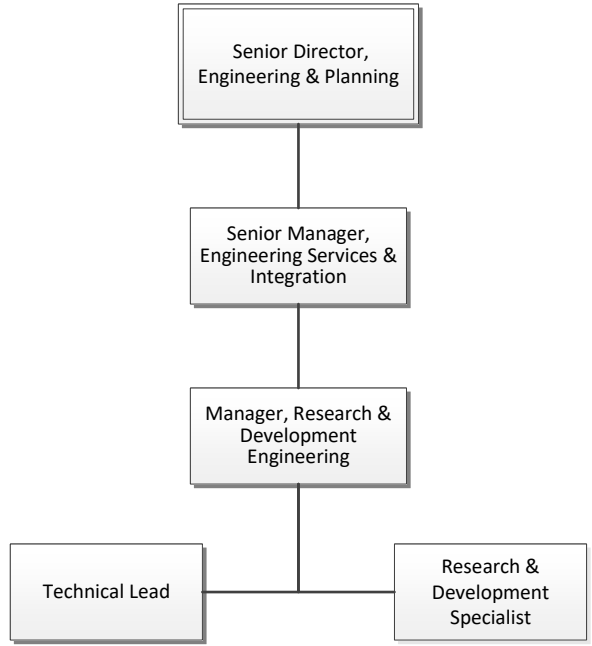
(b) Pdf pg. 217 states: "E1's Innovation team uses established Innovation Goals to define the long-term outcomes of all projects from concept, planning to close." Provide an org chart of this team and identify how many E1 personnel make up the innovation team.

Response IR-50:

(a) Please refer to EfficiencyOne's (E1) response to NSEB IR-16.

(b) The Innovation team is a component of E1's Engineering and Planning team. The team is responsible for managing the Innovation Plan initiatives and is supported by other teams throughout the organization depending on the initiative. E1 projects that 57 percent of the 3.0 FTE's time will be focused on DSM activities with remaining time spent on non-DSM activities. Please refer to Attachment 1 of this response for an Organizational Chart of the Innovation team.

EfficiencyOne
May 2026
Innovation Team



Request IR-51:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, Attachment 5 - Innovation Framework, page 1 of 14 (pdf pg. 216):

E1 refers to its innovation activities but notes that this overview focused on innovation activities of strategic importance to the DSM mandate.

(a) What non-DSM innovation activities are being undertaken by E1 and how are they funded?

Response IR-51:

(a) Non-DSM-funded innovation activities are supported through government funding to deliver outcomes per the objectives of that funding.

Request IR-52:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, Attachment 5 - Innovation Framework, page 2 of 14 (pdf pg. 217): Annual Innovation Plan

(a) Please provide E1's innovation plan for 2027 or its most recently completed innovation plan.

Response IR-52:

(a) Please refer to Attachment 1 of this IR response.

2025 Innovation Plan (exclusive to DSM)

Engineering & Planning (E&P) Department:
Research & Development (R&D) Engineering Team

April 2025



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1 Executive Summary

The purpose of the Innovation Plan is to support EfficiencyOne's (E1) Strategic Plan, its value of innovation, and strategic priorities. The Plan provides a roadmap comprising current and future projects, and their respective resource requirements. The overall objective of the Plan is that innovation projects advance E1's ability to respond to future challenges and seek out opportunities. This document is provided for informational purposes only and outlines E1's DSM-funded Innovation Plan for 2025.

This plan is used for development of annual work plans, supporting initiatives and budgets for the subsequent year.

The following Corporate Innovation Objective was used in past Innovation Plans and served as a clear and measurable directive for each project. This CIO was approved by the Executive Leadership Team (ELT):

Benefits to all Nova Scotian electricity consumers through optimized electricity system costs

This CIO ensures the Innovation Plan meets the ambitions of E1's corporate strategic priorities. In this plan, CIO will refer to a measurable target(s) for at least one of the strategic priorities defined in Section 2 and where possible, meet the definition above. Section 2.5 provides further insights on how the strategic priorities could be considered in setting further CIOs and collecting other insights by project.

ELT have prioritized three subject areas in 2025 that are emerging areas of importance to E1. These subject areas are aligned with E1's existing long-term funding strategy that was approved September 2022 and have since been updated. The subject areas are described in Section 3.1.

2 Strategic Plan

The E1 Strategic Plan identifies four strategic priorities: lead with purpose, build for the long term, grow and evolve, and positively impact communities. The following sections outline three of these four priorities and how the Innovation plan supports and aligns with them.

2.1 Lead with purpose

This Innovation plan will do this by:

- Setting direction for researching, developing, and piloting new programs, measures, and delivery models early. In doing so, E1 is better positioned to achieve its annual and multi-year targets and funding obligations.
- Identifying emerging measures and services to support our customers, funders, and partners to help them transform the way they use energy.
- Developing, testing, and evaluating these potential solutions and implementing programs that drive the energy transition.

2.2 Build for the long term

This Innovation plan will do this by:

- Working with partners to increase capacity to accelerate the energy transition. For example, training contractors on new technologies being tested through projects in the Innovation plan.
- Exploring emerging measures and services, E1 is Investing in approaches to advance industry and market readiness.

2.3 Grow and evolve

This Innovation plan will do this by:

- Seeking out and identifying new opportunities to advance our purpose and mission. For example, testing new programs and services that align with long-term objectives of E1 and electricity ratepayers.
- Leveraging data, tools, and resources allowing E1 to expand its services to meet the evolving needs of its customers.

2.4 Setting Corporate Innovation Objectives

In 2022, The R&D Engineering team identified Corporate Innovation Objectives (CIOs) as a clear and quantifiable way to assess whether a project aligns with subject areas. For 2024, the CIO definition has been refined to ensure the Innovation Plan meets the ambitions of E1's current strategic plan. The CIO is defined as a measurable target for at least one of E1's strategic priorities listed in section 2 and where possible, provides:

Benefits to all Nova Scotian electricity consumers through optimized electricity system costs

This CIO can be used on a project-by-project basis directly, or indirectly, as a measure of the key elements of E1's mission: energy goals, bill savings, and helping achieve net-zero emissions by 2025. Any innovation project included in the Innovation Plan must meet the updated CIO definition.

Criterion 1: New projects must target at least one Strategic Priority

This criterion must be established for all new projects being evaluated by both the R&D Engineering team and approved by ELT. Establishing measurable target(s) that align with at least one of the listed strategic priorities is critical to ensure innovation projects are closely aligned with E1's strategic plan. Section 2 provided insights on how each strategic priority could be considered in practice. Setting a measurable target will require these are specific, measurable, achievable, relevant and time bound.

Criterion 2 (CIO): Benefits to Nova Scotian electricity consumers through optimized electricity system costs

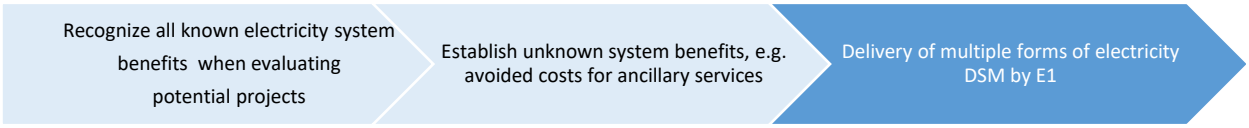
Justification of selection: Activities that produce benefits to the electricity system through DSM and other agreements generally align with all aspects of E1's mission.

As of 2023 energy efficiency is core to E1's business. Innovation is required to help services achieve performance goals as laid out in the DSM supply agreement. As DSM expands into areas other than energy efficiency[1], the E&P team recognizes the value in

[1] Examples of different types of DSM include Energy Efficiency, Demand Response, and Distributed energy resources.

considering all system benefits[2] when assessing new opportunities, i.e. not just avoided cost of generation.

Long-term vision:



3 Innovation Projects

The ELT prioritized three subject areas that support the innovation objectives while aligning with the Strategic Plan. The subject areas are described in Section 3.1.

The 2025 Innovation Roadmap focuses on three areas:

1) Completing active projects
2) Transitioning completed pilots to programs
3) Starting new pilots

The R&D Engineering team conducted a detailed jurisdictional scan and found that the current portfolio of projects is generally well-aligned with market trends in emerging areas of interest. As such, unlike the 2024 Innovation Plan, the 2025 Plan mainly focuses on the existing portfolio and transitioning pilots to programs with a few additions. Feedback from staff suggests that project close-out and transitioning from pilot to program should be a key area of focus.

3.1 Subject Areas

The innovation roadmap (section 3.2) categorizes projects by subject area. A jurisdictional scan of each subject area was conducted in 2023 to identify active programs in North America. Five subject areas were chosen by the ELT for the 2023 Innovation plan and then were re-evaluated in 2025 to only include the three below.

[2] Other types of avoided costs include the avoided cost of carbon, transmission and distribution capacity for constraint regions, non-energy benefits, and ancillary services. Ancillary services is broad and can include things such as spinning reserve, voltage regulation, load following, etc.).

Subject areas will be revised an as-needed basis if other opportunities are identified.

3.1.1 Subject Area 1: Market Transformation

The R&D Engineering team sees substantial energy, demand and GHG savings potential through Market Transformation (MT) programs[3]. In some jurisdictions (such as California, Arizona, and Massachusetts), MT programs result in the majority of portfolio savings. With diminishing savings potential of traditional resource acquisition programs, MT can evolve to become the largest contributor in E1's portfolio of programs. This cannot be achieved in the short-term and thorough groundwork must first be laid through advancement of codes.

The most significant market transformation programs were identified at the Northwest Energy Efficiency Alliance. This includes programs for individual technologies, such as heat pump water heaters and a retail product portfolio initiative; integrated systems, such as high-performance windows and luminaire level lighting controls; and new construction, such as a codes and standards program.

In 2025, the R&D team will complete the hand-off of the HPWH pilot (first market transformation technology) to PM. The team will also help establish annual operating procedures for the HPWH measure that the PM can replicate in coming years without R&D team support. Also, efforts will continue in gaining broader acceptance of MT program delivery.

Looking ahead to the 2027-2031 DSM plan, market transformation efforts will focus on continuing the HPWH measure, completing market research and suggesting the launch of a secondary MT technology. The team will also continue to engage and inform stakeholders on MT and its long-term portfolio potential.

3.1.2 Subject Area 2: Distributed Energy Resources (DERs)

DERs are small-scale energy generation or storage systems that are located close to the point of use, such as in homes, businesses or communities. Typical technologies include solar panels, batteries and combined heat and power systems. DERs play a

[3] E1 Market Transformation Plan

crucial role in DSM by providing flexibility and balancing electricity supply and demand at the consumer level.

In the near-term, Behind-The-Meter batteries (BTM) will be tested as part of a **load flexibility pilot**. This pilot will seek to understand and test demand response use cases (such as cold load pickup, fast frequency response, and renewable following) with existing participant devices in the Eco Shift program. This will help drive the development of a long-term strategy with respect to flexible loads, such as BTM batteries, to provide additional grid benefits and improve the cost effectiveness of demand response programming.

The R&D team will also investigate commercial battery opportunities that may be eligible for Smart Synergy and how these may be incorporated into a long-term load flexibility strategy.

3.1.3 Subject Area 3: Energy Efficiency

The R&D team sees an opportunity for research initiatives that seek to address barriers to energy efficiency to complement existing programming. Several energy efficiency related projects have been identified that stem from insights of past pilot projects. These projects target improving education, raising awareness and building collaborative engagements to improve, or expand adoption of, energy efficient technologies.

In 2025, the generator as a backup research project will seek to address the barrier in industry that considers heat pumps an unreliable source of heat when powered by backup generators. Raising awareness around heat pump/backup generator compatibility addresses homeowner feedback received that other heat sources, such as baseboard electric, are more reliable. Training workshops will be delivered for HVAC contractors on proper ductwork sizing and flow testing for improved energy efficiency of heating system retrofits. An Air to Water Heat Pump working group will also be established to identify and eliminate barriers to this technology as an energy efficient option for hydronic heating systems.

3.2 2025 Innovation Roadmap

The innovation roadmap below, shows a timeline for current innovation projects with significant staff time and direct spend. Note that as currently active come to a close, additional projects will be added to the roadmap in future years. The timelines shown may also be adjusted based on available resources.



Innovation Objective	Subject Areas	Innovation Projects	2025 Q1	2025 Q2	2025 Q3	2025 Q4	2026 Q1	2026 Q2	2026 Q3	2026 Q4	2027 Q1	2027 Q2	2027 Q3	2027 Q4	2028 Q1	2028 Q2	2028 Q3	2028 Q4	2029 Q1	2029 Q2	2029 Q3	2029 Q4	2030 Q1	2030 Q2	2030 Q3	2030 Q4
Ratepayer benefits + GHG reduction	Market Transformation	Adopt schedule A building code amendment[1]	◆																							
		Adopt schedule B building code amendment[1]					◆																			
		Adopt schedule C building code amendment[1]													◆											
		PCF target for net zero codes[2]																					◆			
		2025 retrofit code released[2]	◆																							
		HPWH MT Pilot																								
		Evaluation of savings for MT activities to date									◆															
		27/31 Plan MT programs																								
Ratepayer benefits + GHG reduction	Distributed Energy Resources	DHW DLC direct install pilot																								
		DR load flexibility pilot																								
		Value stacking																								
Ratepayer benefits	Energy Efficiency	Heat pump commissioning research							◆																	
		Generator as a backup research					◆																			
		Ductwork sizing and flow testing workshops					◆																			
		Air to water heat pump working group																								

1. Public Input on Proposed Building Code Amendments, August 14, 2023

2. Pan Canadian Framework on Clean Growth and Climate Change, Page 17, item 1

3.3 Technology Roadmap

The technology roadmap, below, identifies key technology opportunities for research, testing and pilot potential. Note that the categories may differ from the current subject areas. These categories and technologies seek to address identified future opportunities for innovation but some categories have not yet been approved as subject areas. A set of short, medium and long-term deliverables have been developed to map out future objectives for these technologies.

No.	Technology	Description	2025 Action	Short-term Deliverables (1-3 years)	Medium-term Deliverables (3-5 years)	Long-term Deliverables (5+ years)	Sector(s)	Category / Categories
1	Domestic Hot Water Controllers	Direct load control for residential hot water systems	Conduct pilot for central hot water systems in schools and large residential complexes	1) Exhaust provincial central system capacity in schools and MURBs 2) Implement load shifting and load flexibility with DHW controllers	1) Expand load shifting and load flexibility capabilities	1) Expand use of smart hot water heaters as DR resource	Residential	Demand Response
2	Smart thermostats	Thermostats for electric heating systems	Use DRMS to mimic Shifted algorithm	1) Dispatch in groups to reduce snapback and opt-outs	1) Explore summer (cooling setpoint) events	N/A	Residential /Commercial	Demand Response
3	Behind-the-meter batteries	Residential and commercial DERs	Load flexibility pilot through EcoShift	1) Test load flexibility 2) Bring in more OEMs (BYOD program)	1) Expand commercial battery capacity in Smart Synergy	1) Develop a VPP pilot	Residential /Commercial	Demand Response & Distributed Energy Resources

4	Natural Gas Customer-sited generators	Utilize natural gas generators as demand response assets	Review pilot results with EM team and assess pilot	1) Identify target customer segments 2) Identify key barriers and solutions for customers 3) Pilot min. 2 projects before 2026 DR season	2) Expand based on target customer segments and barriers identified	TBD	Commercial	Demand Response
5	Electric Vehicles	Explore load management solutions and V2G adoption barriers	Investigate load management options for residential EV charging	1) Load management for demand response 2) Test V2G	1) Pilot load management solutions for demand response 2) Test V2G	1) Develop a VPP pilot	Residential /Commercial	Demand Response, EV & EVSE
6	IOT (Smart) Devices	Integrate IOT devices with Eco Shift and MT pilot opportunities	HPWH MT Pilot (ongoing)	1) Use Smart DHW tanks for load shifting	1) MT assessment of IOT device categories as a secondary measure	2) Smart panel (integrate with VPP pilot)	Residential /Commercial	Energy Efficiency, Demand Response & Market Transformation
7	Air to Water Heat Pumps	Expand residential and commercial capacity	Study barriers to residential and commercial adoption	1) Draw insights from other jurisdictions, recommendation to ELT. 2) Define MURB and commercial opportunities	1) MT assessment as a secondary measure	1) Expand adoption as smart electrification option	Residential	Strategic Electrification & Market Transformation

8	Recommissioning Commercial Buildings	Buildings that dynamically interact with the grid to optimize energy use	Implement pilot projects with smart building technologies	1) Evaluate energy savings and grid impact	TBD	TBD	Commercial	Energy Efficiency

3.4 Innovation Pilots Overview

The following section provides a narrative description of the Innovation roadmap in section 3.2. The definition of a pilot is located below, as approved by ELT[4]. Pilots are categorized as follows:

New active pilots (2025)

These are new pilots which will become active in 2025.

Continued active pilots (2024)

These are pilots which were active in 2024 and will continue to be active in 2025.

Closed pilots (2025)

These are pilots closed in 2025.

Definition of a pilot

Pilots are small-scale experiments meant to test new ideas and prepare for eventual implementation of the idea being tested for permanent implementation at scale. The objective of a pilot is to:

- Validate that the idea works, i.e. conduct an impact and/or process evaluation as appropriate;
- identify any gaps or flaws in the idea;
- confirm or correct assumptions, e.g. resource requirements;
- collect customer feedback;
- assess industry capacity for delivery; and
- prepare for full implementation

[4] 2021 Innovation Process Mid-Year Review

3.4.1 New active pilots (2025)

The following is a brief description of new pilots which will become active in 2025.

3.4.1.1 DHW DLC direct install

There are three strategic objectives of the DHW DLC direct install pilot, centered around demand response capability, as follows.

The first objective is to work closely with services, business development managers and energy managers to understand and evaluate efficacy of EPI DHW DLC delivery for MURBs. The focus will be to identify areas for improvement in terms of program delivery and optimize uptake for MURB customers.

The second objective is to design, test and evaluate solutions for how to control central hot water in MURBs and other largely untapped customer segments, e.g. schools. Energy managers and business development managers are well-positioned to assist with recruitment.

The third objective is to run flexible load use cases for DHW controllers as part of the load flexibility pilot.

This pilot provides value because MURBs and other customer segments have been identified to represent a potentially significant, cost-effective opportunity to install a select few DHW controllers and achieve significant DR capacity.

For central HW systems, there could be a significant opportunity for demand response curtailment and the key takeaways from the first few installations will inform if future expansion in this area is possible.

3.4.1.2 DR Load flexibility

The DR load flexibility pilot will launch in Q1 of 2025 and will focus on leveraging existing DR technologies/participants in new use cases beyond system peak curtailment. The new use cases may include cold load pickup, fast frequency response and renewable following. This pilot will seek to help address that DR programs do not currently pass cost-effectiveness testing.

The strategic objectives of this pilot are as follows:

- Expand the use cases for DR assets to increase the value of DR to ratepayers, improving program cost-effectiveness.
- Regulatory stakeholders, including NSP, have an interest in these additional DR use cases and the value it brings to the utility. For example, improving grid stability and helping manage the growth of renewable energy generation.
- Investigate the benefits of TVP stacking with NSP.

After the first DR season is complete, evaluation of results and collecting participant feedback will be completed to inform next phases of the pilot. Note that these use cases will not provide direct energy savings, demand savings or DR capacity.

3.4.1.3 Value stacking

The value stacking pilot will launch in Q2 of 2025 and will focus on how to best use behind the meter (BTM) Distributed Energy Resources (DERs) for the customer. For example, peak shaving the customer load vs. discharging to the grid (net meter) vs. participating in demand response programs. What combination (stack) of these methods will provide the most value.

3.4.1.4 Heat pump commissioning and configuration

This pilot will begin in Q2 of 2025 and will focus on configuration of HVAC controls for residential homes with Mini Split Heat Pumps (MSHPs) and other electric heating equipment. MSHPs are very popular in Nova Scotia but they do not often maximize possible savings through control scheme inefficiencies, particularly over-utilizing secondary heat sources.

3.4.2 Continued active pilots (2024)

The following pilot was active in 2024 and will be continued in 2025.

3.4.2.1 Heat pump water heater MT pilot

In 2022, R&D engineering and an expert consultant, Resource Innovations (RI), completed phase I of this project: a market characterisation study to identify an ideal candidate for E1's first MT pilot.

Heat pump water heaters (HPWH) was selected as the most viable measure. Following this study, phase II was completed: a baseline assessment for heat pump water heaters in Nova Scotia.

Phase III of this project, developing the HPWH MT pilot design, was completed in 2024. The market interventions for HPWHs continues in 2025 and beyond.

3.4.3 Closed pilots (2025)

The Deep Retrofit Navigator pilot was undertaken together with Halifax Regional Municipality (HRM) from 2023-2025.

3.4.3.1 Deep Retrofit Navigator pilot

The Deep Retrofit Navigator pilot was designed to provide comprehensive project management support, from an assigned project "Navigator", to complete deep energy retrofits for homeowners in HRM. The pilot helped homeowners identify energy saving measures and provided financial support incentives in the form of rebates/financing to help overcome the financial barrier associated with deep energy retrofits.

The pilot provided meaningful insights, including participant and delivery agent feedback related to the navigator service, establishing three customer segments for targeted engagement with homeowners in the future and competing financing structures, such as Canada Greener Homes, require careful risk mitigation and potential financing restructure. The pilot achieved 533 GJ/year in total energy savings for the participants.

Request IR-53:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, Attachment 5 - Innovation Framework, page 6 of 14: Table 1: Projected Direct Expenditures by Focus Area:

(a) How are the budget amounts for each focus area determined?

(b) Please provide a breakdown of the expenditure amounts for approved vs unapproved projects. For each approved project included in the expenditures, please provide a copy of the project proposal submitted to the executive leadership team for approval, and the record of the approval. If there are less than five approved projects included within the scope of the expenditures shown for 2027-2031, please provide copies of the project proposals and records of approval for the most recent five projects that were approved by the executive leadership team.

Response IR-53:

(a) The spending for the focus areas identified in Table 1 of Appendix A, Attachment 5, were estimated by reviewing where EfficiencyOne (E1) expects to support the successful implementation of the proposed 2027–2031 DSM and the development of the 2032–2036 DSM Plan. Aligned with the approach taken for the total proposed 2027–2031 investment, where levels were constrained to 2026 approved amounts, E1 allocated the innovation funds in a manner that E1 felt reflected prioritization.

The specific innovation projects that E1 will implement during the 2027–2031 DSM Plan period have not yet been individually approved, as project selection and approval will be finalized following the Nova Scotia Energy Board's decision on the 2027–2031 DSM Plan application and as priorities are assessed throughout the duration of the plan.

Request IR-54:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Exhibit E-1, Appendix A, Attachment 5 - Table 4, 5, and Figure 2, pages 11-13 of 14:

(a) Figure 2 notes that market, performance and program readiness are assessed at the concept stage. For each of these items in Tables 4 and 5, please explain what levels are needed for a project to move past the concept stage into the planning stage. Please explain how the various levels identified in Tables 4 and 5 are used as thresholds for determining progression or success in any part of the pilot lifecycle shown in Figure 2.

(b) Figure 2 notes that cost effectiveness threshold is determined at the concept stage. Please explain how the cost effectiveness threshold is determined.

Response IR-54:

(a) Where an innovation activity is focused on an emerging DSM measure, advancing market and performance readiness is the primary objective of the associated research and pilot activities. In this context, Table 4 of Attachment 5, Appendix A, provides a framework for establishing a baseline and monitoring progress toward the innovation objective. Evaluation of progress through the readiness levels is specific to the emerging measure being researched and piloted. The following core questions must be addressed before a DSM measure can be validated and transitioned from innovation into E1's program offerings:

1. Can the supply chain and Nova Scotian market support adoption of the measure at scale?

2. Has the measure's performance been sufficiently validated in field to demonstrate reliable DSM savings?

Alternatively, where an innovation project is focused on an emerging program delivery approach, Table 5 of Attachment 5, Appendix A, provides a framework for establishing a baseline and monitoring progress toward improving DSM program readiness. Program readiness is assessed across two key areas that, along with E1's assessment of risk, must be addressed before a DSM program can be validated and transitioned from Innovation into E1's program offerings:

1. Modelling and/or pilot delivery of the program demonstrates that the program is anticipated to be cost-effective within the Nova Scotia market.
2. Market awareness, together with E1's program delivery knowledge supports reliable participation and DSM savings as validated through successive pilot delivery in the Nova Scotia market.

There are no specific thresholds tied to the readiness indicators during the pilot lifecycle. These metrics are tracked through the execution phase of the project and will be assessed to determine if a project should move from the research to pilot phase or from pilot to program. Specific thresholds are not used because new DSM measures and programs must be evaluated relative to existing E1 programs and therefore require a case-by-case review.

(b) At the concept stage of an innovation project a cost-effectiveness threshold of 1 or greater is the objective.

Request IR-55:

Appendix A - Preferred Plan pp. 1-112 (Attach. 1-5)

Board staff notes that in Appendix A Attachment 4 from E1's 2023-2025 DSM application (M10473), E1 included columns identifying the following: "Gross Per Unit One-Time Incremental Measure Cost ($)", "Per Unit Program Administrative Cost (inclusive of DI costs) ($)", "Per Unit DSM Administrator Cost (Incentive + Administrative) ($)", "Per Unit DSM Customer Cost (Incremental Measure Cost - Incentive) ($)", and "Total Per Unit DSM Cost ($)". Board staff also notes that these columns do not appear to be included in Appendix A Attachment 3 in the current matter. Please explain.

Response IR-55:

Please see Table 1 below for an explanation on why various metrics that were included in the 2023–2025 DSM measure level energy efficiency technical tables were not included in the 2027–2031 measure level energy efficiency and solar-PV technical tables.

Table 1: Metrics in 2023-2025 DSM Plan Application

Column in 2023-2025 DSM Plan Application Attachment 4	Explanation
Gross Per Unit One-Time Incremental Measure Cost ($)	Following the Nova Scotia Energy Board's Decision on the Benefit-Cost Analysis (BCA) Test, the Total Resource Cost (TRC) test was no longer the Board approved cost effectiveness test for DSM and was not included in the 2027–2031 DSM Plan Application. Incremental costs are not an input in the new Board-approved Program Administrator Cost (PAC) test and therefore this column was not included in the 2027–2031 DSM Plan Application, Appendix A – Attachment 3.
Per Unit Program Administrative Cost (inclusive of DI costs) ($)	For the 2023–2025 DSM Plan, program administrator costs were allocated to individual measures. The modelling expert advised this was not considered best

Column in 2023-2025 DSM Plan Application Attachment 4	Explanation
	practice as program administrative costs are not tied to individual measures but rather are incurred at the program component level of a Plan and do not vary based on the number of measures. For the 2027–2031 DSM Plan, program administrator costs were therefore applied at the program component level and were not included in the 2027–2031 DSM Plan Application, Appendix A – Attachment 3.
Per Unit DSM Administrator Cost (Incentive + Administrative) ($)	Please see above explanation for 'Per Unit Program Administrative Cost (inclusive of DI costs) ($)'
Per Unit DSM Customer Cost (Incremental Measure Cost - Incentive) ($)	Please see above explanation for 'Gross Per Unit One-Time Incremental Measure Cost ($)'
Total Per Unit DSM Cost ($)	'Total Per Unit DSM Cost ($)' was a metric that looked at both incentive and incremental costs. It is not a relevant metric to the PAC test. Please see above explanation for 'Gross Per Unit One-Time Incremental Measure Cost ($)' for further details.

Request IR-56:

Appendix B - Rate and Bill Impact Analysis, 2027-31 DSM Resource Plan and 2026 Historical, pp. 1-23 (Attach. 1-10)

Please provide the growth assumptions used in NS Power's projected energy and demand sales from 2011-2055 and where available by rate class.

Response IR-56:

Please refer to Appendix B, Attachment 7: NS Power Rate Model – 2027–2031 Preferred Plan and 2026 Historical, tab: 'COSS Data Inputs'. This includes the following data by year and by rate class:

- MWh Sales: Columns M:V
- MWh Requirement at Generator: Columns AG:AP
- Average of 3 Winter Month Coincident Peak at Generator (kWs): Columns AQ:AZ

Request IR-57:

Appendix B - Rate and Bill Impact Analysis, 2027-31 DSM Resource Plan and 2026 Historical, pp. 1-23 (Attach. 1-10)

Pdf page 290 states that program costs for the 2027-2031 DSM Plan will be completely recovered from 2027-2031 and 2011-2026. Please confirm, or explain otherwise, that the cost recovery for program costs in 2027-2031 will be recovered in the same period.

(a) Please explain how E1 expects to recover costs in 2031 that are incurred in 2031.

(b) What are the outstanding program costs from 2011-2026

Response IR-57:

Aligned with the Nova Scotia Energy Board's (NSEB) approved DSM Cost Recovery Rider (DCRR) process, EfficiencyOne (E1) expects program costs for 2027–2031 to be recovered within that same period. The only exception is any required true ups for under or over recovery, which will be recovered through the Balance Adjustment (BA) mechanism in future years.

(a) Approved 2031 DSM costs are expected to be recovered in 2031 in accordance with the DCRR process. The DCRR includes a Balance Adjustment, which will be informed by E1's surplus for 2027–2031 based on actual results with E1 reporting the surplus to NS Power to be included as part of the 2028 DCRR.

(b) In accordance with the DCRR process, balance adjustments include adjustments by both NS Power and E1. These adjustments include:

- Adjustments to true-up differences between NS Power collections and the amount that was intended to be collected by rate class through the Program Cost Recovery which is informed by E1's DSM Plan; and
- Any surplus, which includes interest earned and underspending by rate class, that results from E1's implementation of the NSEB approved DSM Plan at the end of the DSM Plan period.

Request IR-58:

Appendix B - Rate and Bill Impact Analysis, 2027-31 DSM Resource Plan and 2026 Historical, pp. 1-23 (Attach. 1-10)

Exhibit E-1, Appendix B, Attachment 6 – NS Power Pricing Methodology, page 8 of 16 (pdf pg.310):

It is noted that DSM-related costs are apportioned to rate classes based on the "25/75 rule".

(a) Please confirm whether the rate and bill impact assessment information provided in this application is based on the allocation of 75% of the cost to the related rate class or 100%, as recently approved in NS Power's recent general rate application.

(b) If the rate and bill impact assessment information in the application is not based on a 100% allocation to customer classes, please provide an update to Table 1 [Exhibit E-1, Appendix B, page 12 of 23] based on a 100% allocation.

Response IR-58:

(a) EfficiencyOne (E1) apportioned costs 75 percent to rate classes and 25 percent to the system, in accordance with the Cost of Service Study in effect during plan development.

(b) Please refer to Table 1 of this IR response.

Table 1: Rate and Bill Impacts by Rate Class as a Result of 2027-2031 DSM Preferred Plan Activities (100% Rate Class Cost Allocation)

Rate Class	Rate Codes	Average Rate Impact (%)	Average Rate Impact (cents/kWh)	Participant Average Bill Impact	Non-Participant Average Bill Impact	Total Class Average Bill Impact
Residential	2, 3, 6, 9, 16 (Domestic)	0.6%	0.09	-16.3%	0.5%	-0.7%
Small General	10	0.9%	0.14	-37.3%	0.8%	-2.0%
General	11	0.8%	0.11	-11.6%	0.8%	-3.1%
Large General	12	0.4%	0.05	-3.5%	0.4%	-3.3%
Small Industrial	21	0.8%	0.11	-27.5%	0.8%	-3.1%
Medium Industrial	22	-0.1%	-0.02	-4.3%	-0.1%	-2.1%
Large Industrial	23, 25, one-part high voltage real time pricing tariff	0.6%	0.05	-3.9%	0.6%	-3.4%
Municipal	24	0.1%	0.01	-0.2%	0.1%	-0.2%

In preparing this response, an error was identified in the referenced table from Appendix B. Please refer to Table 2 of this IR response for the corrected table. The Average Rate Impact (cents/kWh) for the Municipal rate class has been revised from 0.05 to 0.03.

Table 2: Correction of Appendix B Table 1 - Rate and Bill Impacts by Rate Class as a Result of 2027-2031 DSM Preferred Plan Activities

Rate Class	Rate Codes	Average Rate Impact (%)	Average Rate Impact (cents/kWh)	Participant Average Bill Impact	Non-Participant Average Bill Impact	Total Class Average Bill Impact
Residential	2, 3, 6, 9, 16 (Domestic)	0.6%	0.09	-16.3%	0.5%	-0.7%
Small General	10	0.9%	0.14	-37.3%	0.8%	-2.0%
General	11	0.7%	0.11	-11.6%	0.7%	-3.1%
Large General	12	0.3%	0.04	-3.5%	0.3%	-3.3%
Small Industrial	21	0.8%	0.11	-27.5%	0.8%	-3.1%
Medium Industrial	22	-0.1%	-0.03	-4.3%	-0.1%	-2.2%
Large Industrial	23, 25, one-part high voltage real time pricing tariff	0.6%	0.05	-4.0%	0.6%	-3.4%
Municipal	24	0.3%	0.03	0.0%	0.3%	0.0%

Request IR-59:

Appendix B - Rate and Bill Impact Analysis, 2027-31 DSM Resource Plan and 2026 Historical, pp. 1-23 (Attach. 1-10)

In reference to Appendix B, Attachment 1, the worksheet Preferred Plan, the table and the graph Rate Impacts by Resource show an increase in rate impacts associated with solar pv. In column AQ, please explain why there will be no rate impact in 2027 and why the rate impact diminishes but remains positive from 2028 to 2046.

Response IR-59:

The Residential rate impacts (Column AQ of Appendix B, Attachment 1, Preferred Plan worksheet) are summarized as follows:

- 2027: 0% rate impact
- 2028–2031: 0.07% average rate impact
- 2032–2055: 0.01% average rate impact

There is no Solar-PV rate impact in 2027, as the program is proposed to begin in 2028. The Solar-PV rate impacts are highest (0.07%) from 2028 to 2031, reflecting the recovery of program costs, which exerts upward pressure on rates.

From 2032 to 2055, the rate impacts decline but remain positive at approximately 0.01%. During this period, program cost recovery has ended; however, two offsetting factors continue to influence rates: avoided costs (which reduce rates) and lost revenues (which increase rates). The small net positive impact indicates that these effects are largely balanced, with lost revenues slightly exceeding avoided costs.

Request IR-60:

Appendix B - Rate and Bill Impact Analysis, 2027-31 DSM Resource Plan and 2026 Historical, pp. 1-23 (Attach. 1-10)

In reference to Appendix B, Attachment 1, the worksheet Preferred Plan, the table and the graph for Total Customer Bill Impacts by Resource, please explain the solar pv program will have a positive effect on customer bills from 2028 to 2031.

Response IR-60:

Total customer bill impacts reflect the combined effects of both participants and non-participants. These two groups experience different bill effects from Solar-PV:

- Solar-PV participants experience bill reductions (savings) in every year from 2028 to 2055.
- Non-participant bills are only affected by the rate impacts of Solar-PV and see neutral to increased bill impacts over 2028 to 2055.

When these two groups are combined, the overall impact is an increase in customer bills during the 2028–2031 period, and lower impacts from 2032 to 2055. These effects are most evident in the Residential rate class, with lower impacts in the Business, Non-profit and Institutional (BNI) rate classes.

Please refer to EfficiencyOne's (E1) response to NSEB IR-59 for additional information on the rate impacts of Solar-PV.

Request IR-61:

Appendix B - Rate and Bill Impact Analysis, 2027-31 DSM Resource Plan and 2026 Historical, pp. 1-23 (Attach. 1-10)

Please explain why the Average Participant Bill Impact for solar pv is 0% in 2027.

Response IR-61:

The Average Participant Bill Impact for Solar PV is 0% in 2027 because the Solar-PV resource is not proposed to launch until 2028 (i.e., there are no participant impacts in 2027).

Request IR-62:

Exhibits E-2 - 2025 DSM Annual Progress Report

Please provide a table with the free ridership levels used in the 2025 DSM Evaluation.

Response IR-62:

Please refer to Table 7[1] in the Overall Executive Summary Evaluation Report, provided below, which lists all Free-ridership levels used in the 2025 DSM Evaluation.

Table 7: 2025 Free-ridership, Spillover, and NTGRs

Program Component and Measure Type		Free-ridership Levels	Spillover Levels	NTGRs
Residential				
Appliance Retirement[a]	Refrigerators	43%	0%	0.57
	Freezers	45%		0.55
	Air Conditioners	47%		0.53
	Small Refrigerators	32%		0.68
	Small Freezers	32%		0.68
	Dehumidifiers	0%		1.00
Instant Savings	LED Lamps[a]	39%	9%	0.70
	LED Fixtures[a]	26%	2%	0.76
	Dimmer Switches	-	-	0.75
	Indoor Motion Sensors	-	-	0.75
	Indoor Motion Sensors with Dimmer Switches	-	-	0.75
	Outdoor Motion Sensors	-	-	0.75
	Heavy-duty Outdoor Timers	-	-	0.75
	Solar Fixtures[a]	26%	2%	0.76
	Power Bars with Integrated Timers	-	-	0.86
	Smart Power Bars	-	-	0.86
	Programmable Thermostats	-	-	0.86

[1] M12780, Exhibit E-3, 2025 DSM Programs Evaluation Reports, Overall Executive Summary, March 17, 2026, page 25-26.

Program Component and Measure Type		Free-ridership Levels	Spillover Levels	NTGRs
	Smart Thermostats for Mini-split Heat Pumps	-	-	0.86
	Smart Thermostats for Electric Baseboards	-	-	0.86
	Smart Thermostats for Electric In-floor Heating	-	-	0.86
	Efficient Clothes Washers	51%	3%	0.52
	ENERGY STAR® Certified Clothes Dryers	48%	3%	0.55
	Efficient Combined Clothes Washers and Dryers	50%	3%	0.53
	ENERGY STAR Certified Room Air Purifiers	-	-	0.65
	ENERGY STAR Certified Dehumidifiers	34%	3%	0.69
	ENERGY STAR Certified Variable Speed Pool	24%	3%	0.79
	ENERGY STAR Heat Pump Water Heaters	-	-	1.00
	ENERGY STAR Certified Dishwashers	-	-	0.55
	ENERGY STAR Certified Bathroom and Utility Fans	38%	3%	0.65
	Outdoor Clotheslines and Outdoor Drying Racks	-	-	0.65
Home Energy Assessment[a]	Energy Efficiency Measures	17%	1%	0.84
	Solar PV Measures	26%	1%	0.75
Green Heat[a]	MSHPs	48%	-	0.52
	Biomass and Solar	47%		0.53
	Demand Reduction	9%		0.91
	Central Air-source Heat Pumps (CASHPs) and Air-to-water Heat Pumps (AWHPs)	33%		0.67
Efficient Product Installation [a]	LED Lamps and Lighting-Related Products, Non-low-income Participants	16%	8%	0.92
	LED Lamps and Lighting-Related Products, Low-income Participants	0%	0%	1.00
	Smart and Advanced Learning Thermostats, Non-low-income Participants	9%	8%	0.99
	Smart and Advanced Learning Thermostats, Low-income Participants	0%	0%	1.00
	DHW Products, Non-low-income Participants	11%	8%	0.97
	DHW Products, Low-income Participants	0%	0%	1.00
	Air Sealing Products, Non-low-income Participants	12%	8%	0.96
	Air Sealing Products, Low-income Participants	0%	0%	1.00
	Humidity Sensors, Non-low-income Participants	0%	8%	1.08
	Humidity Sensors, Low-income Participants	0%	0%	1.00
Mi'kmaw Home Energy Efficiency Project		-	-	1.00
Affordable Multifamily Housing		-	-	1.00
Affordable Single-family Homes		-	-	1.00
Residential Behaviour		-	-	-
BNI				
	Lighting	6%	0%	0.94
	HVAC	17%	0%	0.83

Program Component and Measure Type		Free-ridership Levels	Spillover Levels	NTGRs
Business Energy Rebates – Application	All	9%	0%	0.91
	Renewable Generation[a]	0%	0%	1.00
Business Energy Rebates – Instant Rebates	LED Linear Fixtures[a]	8%	-	0.92
	LED Linear Lamps[a]	15%		0.85
	LED Outdoor Fixtures[a]	15%		0.85
	Other Measures[a]	-		1.00
Custom Retrofit	Regular Retrofit Projects	8%	0%	0.92
	Solar PV Projects	38%	1%	0.63
	Compressed Air Leak Audit Projects	8%	0%	0.92
Custom Pay-for-Performance		8%	-	0.92
Custom New Construction		18%	-	0.82
Custom Building Optimization[a]		9%	0%	0.91
Strategic Energy Management[a]		-	-	1.00
Small Business Energy Solutions	Audit Path[a]	20%	0%	0.80
	DIY Path[a]	12%	-	0.88
[a] Net-to-gross ratios were determined based on the results of past evaluations.				

Request IR-63:

Exhibits E-2 - 2025 DSM Annual Progress Report

Please describe the Nova Scotia specific GHG emissions factor used in the evaluation.

(a) Did E1 modify the factor to provide a better fit for their programs and services?

i) If so, please explain the adjustments.

ii) If not, why not?

Response IR-63:

(a) The following IR response has been provided by Econoler.

In 2025, the established GHG emission factor was 469.3 tonnes of CO2 eq/GWh compared to 472.2 in 2024. As noted in each 2025 evaluation report including the 2025 Overall Executive Summary report[1], the Evaluator updated the GHG emission factor in 2025 with the most up-to-date available information. More precisely, the footnote states:

> "At the time of writing, 2025 data were not yet available. The Nova Scotia-specific factor was obtained from Nova Scotia Power's 2024 total system emissions data (5,314,847 CO2 eq tonnes) and total electricity generation (11,326 GWh) was drawn from the following two sources: Nova Scotia Power, Total System Emissions, https://www.nspower.ca/clean-energy/air-emissions-reporting (last accessed January 15, 2026) and Emera Inc., Emera

[1] M12780, Exhibit E-3, 2025 DSM Programs Evaluation Reports, 2025 DSM Programs Evaluation Overall Executive Summary, March 24, 2026, page 12.

Inc. 2024 Annual Report, p. 32, available at https://s205.q4cdn.com/781121964/files/doc_financials/2024/ar/2024_Emera_Annual_Report.pdf (last accessed January 15, 2026)."

Request IR-64:

Exhibits E-2 - 2025 DSM Annual Progress Report

In reference to Table 5: Comparison of 2025 Evaluated and Tracked Electrical Energy Savings at the Generator:

(a) Please explain the Net Realization Rate of 101% for Affordable Single-family Homes.

(b) How were the Lifetime Net Electrical Energy Savings calculated?

(c) Why are there entries under Difference in Net Savings for five Residential programs?

Response IR-64:

(a) The Net Realization Rate of 101% for Affordable Single-family Homes is the result of the Evaluator including non-modelled heat pump savings from 2024 that were not previously included as noted in the 2025 Evaluation Report Section 7.4 "Realization Rate" of the Existing Residential Program Evaluation for Affordable Single-family Homes as follows:[1]

> The electrical energy savings determined by the Evaluator were approximately 1% higher than the savings initially tracked by E1 due to the addition of 2024 unclaimed savings from non-modelled heat pump measures.

[1] M12780, Exhibit E-3, 2025 DSM Programs Evaluation Reports, Existing Residential Program, March 13, 2026, page 26.

Additional details are provided in Sections 7.2 and 7.2.5 as provided below. Section 7.2 "Gross Savings" of the Existing Residential Program Evaluation for Affordable Single-family Homes notes the following:[2]

> It should also be noted that the Evaluator adjusted the calculation approach for non-modelled heat pumps after the 2024 DSM evaluation was completed. Although this adjustment occurred post-evaluation, the Evaluator agreed with E1 that the updated methodology should have been applied since April 2024. As a result, the Evaluator retroactively applied this methodology to the relevant portion of 2024 reporting and included, herein, the resulting difference in savings from that adjustment.

Section 7.2.5 "Evaluated Gross Savings" of the Existing Residential Program Evaluation for Affordable Single-family Homes notes the following for Additional 2024 Non-modelled Heat Pumps measure:[3]

> Additional savings for non-modelled heat pumps recalculated for the period from April 1 to December 31, 2024. Following a post-evaluation adjustment to the calculation approach, the Evaluator retroactively applied the updated methodology to the savings from this period and included the resulting difference in electrical energy and peak demand savings.

(b) For each Program Component the Effective Useful Life (EUL) values per measure category are multiplied by the Net Electrical Energy Savings at the Generator to determine the Net

[2] Ibid., page 20.
[3] Ibid., Table 16, page 24.

Lifetime Electrical Energy Savings at the Generator. In each Program Component Evaluation report there is a table called "Evaluated 2025 Program Component Net Electrical Energy and Peak Demand Savings" that shows this calculation. For example, the Appliance Retirement Program Component Table 10[4] shows the EUL (years) for Refrigerators as 4.0 years and the Net Electrical Energy Savings as 0.076 GWh, resulting in Net Lifetime Electrical Energy Savings of 0.303 GWh.

The measure category Lifetime Electrical Energy Savings are then summed at the Program Component level and presented in Table 5 of the Overall Executive Summary report.[5] For the above example, Appliance Retirement is shown as 0.461 GWh in Table 5 of the Overall Executive Summary Report and Table 10 in the Residential Efficient Product Rebates Program Evaluation Report.

(c) Table 5 of the Overall Executive Summary presents three residential program components (i.e., Instant Savings, Affordable Single-family Homes and Efficient Product Installation) with values for Difference in Net Savings (GWh). These program components had a difference between the Tracked Annual Net Savings and Evaluated Annual Net Savings, the reasons for these 'Difference in Net Savings' are provided in the table below.

Program Component	Tracked Annual Net Savings (GWh)	Evaluated Annual Net Savings (GWh)	Difference in Net Savings (GWh)	Reason for Difference between Tracked and Evaluated
Instant Savings	15.981	11.430	-4.551 (11.430-15.981 = -4.551)	Tracked used previous NTGRs for non-lighting products (1.00) and Evaluated used the results from the 2025 literature

[4] Ibid., Residential Efficient Product Rebates Program, March 4, 2026, page 13.
[5] Ibid., Overall Executive Summary, March 17, page 16.

Program Component	Tracked Annual Net Savings (GWh)	Evaluated Annual Net Savings (GWh)	Difference in Net Savings (GWh)	Reason for Difference between Tracked and Evaluated
				review[6] to establish NTGRs for non-lighting products. The overall program NTGR was updated from 0.98 in 2024 to 0.77 in 2025.[7]
Affordable Single-family Homes	6.059	6.135	0.076 (6.135 – 6.059 = 0.076)	Tracked did not include unclaimed savings from 2024 for non-modelled heat pump measures, while Evaluated did include those savings. See response to part a) of this IR.
Efficient Product Installation	7.338	7.300	-0.038 (7.300-7.338 = -0.038)	Evaluated was 1% lower than tracked due to the overall NTGR values updated with the proportions of each product category per participant type. This update only impacts the overall NTGR value used for smart thermostats.[8]

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[6] Ibid., Residential Efficient Product Rebates Program Appendix Report, Appendix IV Instant Savings Net-to-Gross Ratio Literature Review, March 4, 2026.
[7] Ibid., Residential Efficient Product Rebates Program, March 4, 2026, page 37. Section 7.4 for Instant Savings Program Component explains the difference between tracked and evaluated net electrical energy savings.
[8] Ibid., Existing Residential Program, March 13, 2026, page 63.

Request IR-65:

Exhibits E-2 - 2025 DSM Annual Progress Report

With respect to the 2025 setting targets for the net peak demand savings within Custom Incentives, does E1 do an assessment of the customers to determine the customer's energy usage during peak demand before the customer qualifies for the incentive or any other form of screening to ensure that the custom incentive will reduce net peak demand?

Response IR-65:

The 2025 targets for net peak demand savings within Custom Incentives, as approved in the 2023–2025 DSM Plan, were established based on the modelling assumptions and outputs for the 2023–2025 DSM Plan. Achieved net peak demand savings are tracked by EfficiencyOne through the implementation of the DSM Plan and subsequently evaluated each year. Through the annual DSM evaluation of Custom Incentives, the Evaluation Consultant reviews a sample of Custom Incentive projects which includes reviewing peak demand savings calculations to ensure that savings for individual measures will occur during the utility's peak period.

Request IR-66:

Exhibits E-2 - 2025 DSM Annual Progress Report

Please provide the NTGR Calculations in excel format with cells and formula intact and protections removed.

Response IR-66:

The following IR response has been provided by Econoler:

Depending on the program component or service, the NTGR is established, and then applied, at either a program component or service level (e.g., Custom Incentives New Construction), project level (e.g., Custom Retrofit) or measure level (e.g., Efficient Product Installation).

NTGRs are established based on free-ridership and spillover using the following equation.

NTGR = (1 – % Free-ridership + % Spillover)

Table 7 of the Overall Executive Summary[1], presented below, presents the free-ridership and spillover values used to derive the NTGRs, which are then applied at the relevant measure, project or program component level as appropriate.

Table 7: 2025 Free-ridership, Spillover, and NTGRs

Program Component and Measure Type	Free-ridership Levels	Spillover Levels	NTGRs
Residential			

[1] M12780, Exhibit E-3, 2025 DSM Programs Evaluation Reports, 2025 DSM Programs Evaluation, Overall Executive Summary, March 24, 2026, page 25.

Program Component and Measure Type		Free-ridership Levels	Spillover Levels	NTGRs
Appliance Retirement[a]	Refrigerators	43%	0%	0.57
	Freezers	45%		0.55
	Air Conditioners	47%		0.53
	Small Refrigerators	32%		0.68
	Small Freezers	32%		0.68
	Dehumidifiers	0%		1.00
Instant Savings	LED Lamps[a]	39%	9%	0.70
	LED Fixtures[a]	26%	2%	0.76
	Dimmer Switches	-	-	0.75
	Indoor Motion Sensors	-	-	0.75
	Indoor Motion Sensors with Dimmer Switches	-	-	0.75
	Outdoor Motion Sensors	-	-	0.75
	Heavy-duty Outdoor Timers	-	-	0.75
	Solar Fixtures[a]	26%	2%	0.76
	Power Bars with Integrated Timers	-	-	0.86
	Smart Power Bars	-	-	0.86
	Programmable Thermostats	-	-	0.86
	Smart Thermostats for Mini-split Heat Pumps	-	-	0.86
	Smart Thermostats for Electric Baseboards	-	-	0.86
	Smart Thermostats for Electric In-floor Heating	-	-	0.86
	Efficient Clothes Washers	51%	3%	0.52
	ENERGY STAR® Certified Clothes Dryers	48%	3%	0.55
	Efficient Combined Clothes Washers and Dryers	50%	3%	0.53
	ENERGY STAR Certified Room Air Purifiers	-	-	0.65
	ENERGY STAR Certified Dehumidifiers	34%	3%	0.69
	ENERGY STAR Certified Variable Speed Pool	24%	3%	0.79
	ENERGY STAR Heat Pump Water Heaters	-	-	1.00
	ENERGY STAR Certified Dishwashers	-	-	0.55
	ENERGY STAR Certified Bathroom and Utility Fans	38%	3%	0.65
	Outdoor Clotheslines and Outdoor Drying Racks	-	-	0.65
Home Energy Assessment[a]	Energy Efficiency Measures	17%	1%	0.84
	Solar PV Measures	26%	1%	0.75
Green Heat[a]	MSHPs	48%	-	0.52
	Biomass and Solar	47%		0.53
	Demand Reduction	9%		0.91
	Central Air-source Heat Pumps (CASHPs) and Air-to-water Heat Pumps (AWHPs)	33%		0.67
Efficient Product Installation [a]	LED Lamps and Lighting-Related Products, Non-low-income Participants	16%	8%	0.92

Program Component and Measure Type		Free-ridership Levels	Spillover Levels	NTGRs
	LED Lamps and Lighting-Related Products, Low-income Participants	0%	0%	1.00
	Smart and Advanced Learning Thermostats, Non-low-income Participants	9%	8%	0.99
	Smart and Advanced Learning Thermostats, Low-income Participants	0%	0%	1.00
	DHW Products, Non-low-income Participants	11%	8%	0.97
	DHW Products, Low-income Participants	0%	0%	1.00
	Air Sealing Products, Non-low-income Participants	12%	8%	0.96
	Air Sealing Products, Low-income Participants	0%	0%	1.00
	Humidity Sensors, Non-low-income Participants	0%	8%	1.08
	Humidity Sensors, Low-income Participants	0%	0%	1.00
Mi'kmaw Home Energy Efficiency Project		-	-	1.00
Affordable Multifamily Housing		-	-	1.00
Affordable Single-family Homes		-	-	1.00
Residential Behaviour		-	-	-
BNI				
Business Energy Rebates – Application Rebates [a]	Lighting	6%	0%	0.94
	HVAC	17%	0%	0.83
	All	9%	0%	0.91
	Renewable Generation[a]	0%	0%	1.00
Business Energy Rebates – Instant Rebates	LED Linear Fixtures[a]	8%	-	0.92
	LED Linear Lamps[a]	15%		0.85
	LED Outdoor Fixtures[a]	15%		0.85
	Other Measures[a]	-		1.00
Custom Retrofit	Regular Retrofit Projects	8%	0%	0.92
	Solar PV Projects	38%	1%	0.63
	Compressed Air Leak Audit Projects	8%	0%	0.92
Custom Pay-for-Performance		8%	-	0.92
Custom New Construction		18%	-	0.82
Custom Building Optimization[a]		9%	0%	0.91
Strategic Energy Management[a]		-	-	1.00
Small Business Energy Solutions	Audit Path[a]	20%	0%	0.80
	DIY Path[a]	12%	-	0.88
[a] Net-to-gross ratios were determined based on the results of past evaluations.				

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Table 5[2] and Table 6[3] of the Overall Executive Summary[4] present NTGR values at the program component level. These values represent averages, calculated as the ratio of evaluated annual net savings to evaluated annual gross savings for each program component.

[2] Ibid., page 16.
[3] Ibid., page 17.
[4] Ibid, page 25.