



EfficiencyOne

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended

-and-

IN THE MATTER OF An Application by EfficiencyOne for Approval of the 2027–2031 Demand Side Management (DSM) Purchase Agreement between EfficiencyOne and Nova Scotia Power Inc., the establishment of a final agreement between the parties, and approval of a 2027–2031 DSM Resource Plan

Rebuttal Evidence of EfficiencyOne

M12780

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TABLE OF CONTENTS

1. INTRODUCTION.....	1
2. SYNAPSE EVIDENCE	1
2.1 Strategic Electrification	1
2.2 Demand Response	4
3. CONSUMER ADVOCATE EVIDENCE.....	11
3.1 Plan Scenarios and Savings Targets.....	11
3.2 Unit Costs.....	13
3.3 Pre-weatherization Barriers	16
3.4 Residential Heat Pumps	16
4. NOVA SCOTIA POWER EVIDENCE.....	19
4.1 Demand Response	19
4.2 Strategic Electrification	27
4.3 Solar-PV.....	32
5. SOLAR NOVA SCOTIA EVIDENCE	34
5.1 BNI DSM.....	34
5.2 Demand Response	38
5.3 Strategic Electrification	40
6. EASTWARD ENERGY EVIDENCE.....	41
6.1 Custom New Construction Program Baseline.....	42
6.2 Custom New Construction Program Incentive Structure.....	45

LIST OF APPENDICES

Appendix A: Apex Analytics Rebuttal Testimony

1. INTRODUCTION

On March 31, 2026, EfficiencyOne (“E1”) filed its Application for Approval of the 2027–2031 Demand Side Management (DSM) Purchase Agreement between E1 and Nova Scotia Power Inc., the establishment of a final agreement between the parties, and approval of a 2027–2031 DSM Resource Plan. Following responses to Information Requests (“IRs”) from E1, evidence was filed on June 23, 2026, by Synapse Energy Economics (“Synapse”), consultants for the Nova Scotia Energy Board (the “NSEB” or “Board”), as well as the following intervenors: Eastward Energy Incorporated, the Consumer Advocate, Nova Scotia Power Inc., and Solar Nova Scotia (the “Intervenor Evidence”). Responses to IRs on the Intervenor Evidence and the evidence of Synapse were filed on July 17, 2026 (“Intervenor Evidence RIRs”).

E1 is filing this Rebuttal Evidence in response to the evidence and responses to IRs filed by the intervenors and Synapse.

2. SYNAPSE EVIDENCE

Alice Napoleon of Synapse Energy Economics, Inc. (“Synapse”) provided evidence on behalf of Counsel to the Board. Ms. Napoleon’s evidence was filed as E-23. This section of the Rebuttal Evidence sets out new evidence of E1 responding to new concerns raised in Ms. Napoleon’s evidence regarding strategic electrification (“SE”) and demand response (“DR”) programs in the 2027–2031 DSM Plan.

2.1 STRATEGIC ELECTRIFICATION

2.1.1 CONSTRAINED FEEDERS

Synapse

At page 29, line 19 – page 30, line 3, Ms. Napoleon suggests E1 use data to target electrification efforts on non-constrained feeders:

Q. Are there other considerations E1 should account for with regards to electrification?

A. Yes. NS Power has identified feeders that are currently constrained and NS Power is working on transmitting this information to E1. For these constrained feeders, there is a dollar benefit to reducing electricity use and a cost to increasing electricity use. E1 should use this locational data to target electrification efforts to feeders that are not constrained.

E1 Rebuttal Evidence

E1 does not oppose using locational data to inform where strategic electrification effort is directed, and agrees in principle that increasing load on constrained feeders should be avoided where reasonably practicable. E1 notes, however, that the feeder-constraint information Ms. Napoleon relies upon is still being developed and transmitted by NS Power, and that feeder and Advanced Metering Infrastructure (AMI) data availability has been subject to disruption; meaningful locational targeting is therefore contingent on E1 receiving reliable, current data from NS Power. Under E1's Innovation Framework, Process and Plan for 2027–2031, E1 will explore DSM in constrained areas of the grid, subject to the availability of feeder and AMI data. Within the approved plan resources, E1 may also explore the locational implications of DSM specific to SE, such as required foundational activities as outlined in the Distributed Energy Resource Integration Roadmap (DERIR)¹, and program implementation and equity considerations.

2.1.2 LOW-INCOME AND EQUITY PROGRAM INCENTIVES**Synapse**

At page 30, lines 4 – 7, Ms. Napoleon recommends E1 provide incentives in the low-income and equity program components for long-term maintenance and repairs for customers who convert to heat pumps from oil heating:

Also, E1's low-income programs include incentives for long-term maintenance and repairs for customers that convert to heat pumps from electric resistance heating. E1 should provide this incentive for low-income households who convert to heat pumps from oil heating as well.

E1 Rebuttal Evidence

E1 is supportive in principle of the objective underlying Ms. Napoleon's recommendation and recognizes that low-income households converting from oil heating face real affordability and reliability challenges. E1 notes that extending long-term maintenance and repair incentives to oil-to-heat-pump conversions is not, however, a cost-free adjustment. Strategic Electrification as modelled during the DSM Plan development did not include a dedicated low-income and equity program where heat pumps are installed at no cost to homeowners. Strategic Electrification as modelled did not achieve cost effectiveness results of equal to or greater than 1.0 and the program as Ms. Napoleon recommends would have even higher

¹ M12177, Distributed Energy Resource Integration Roadmap, June 30, 2026.

costs which would result in lower cost effectiveness results, placing additional pressure on portfolio cost-effectiveness and on the affordability objective that frames the Plan.

2.1.3 RETAIN HOME ENERGY ASSESSMENT REQUIREMENT FOR ELECTRIFICATION

Synapse

At page 30, lines 8 – 13, Ms. Napoleon recommends E1 maintain the current Oil to Heat Pump Affordability (OHPA) requirement that home energy assessments be conducted prior to electrification:

In addition, E1 should maintain the current [OHPA] OPRA requirement that home energy assessments be conducted prior to electrification, which means that E1 may need to increase the low-income budget for home energy assessments. If a home energy assessment identifies weatherization as an opportunity, E1 should encourage the customer to weatherize when they electrify to achieve additional electricity cost savings and energy affordability benefits.

E1 Rebuttal Evidence

E1 agrees with the value of home energy assessments and with encouraging weatherization at the time of electrification where an assessment identifies that opportunity, consistent with E1's response to the Consumer Advocate on pre-weatherization. E1 notes, as Ms. Napoleon acknowledges, that maintaining the OHPA requirement that a home energy assessment be conducted prior to electrification would likely require an increase to the cost of the program further impacting the cost effectiveness results of Strategic Electrification. E1 cautions against prescribing universal pre-electrification assessment requirements as part of program design.

2.1.4 TARGET LOW-INCOME AND EQUITY CUSTOMERS FOR ELECTRIFICATION

Synapse

At page 30, line 14 – page 31, line 2, Ms. Napoleon recommends that E1 target electrification to low- and moderate-income customers:

Lastly, a 2024 report titled A Way Forward: A Made-In-Nova Scotia Home Energy Affordability Program recommends that E1 target electrification to low- and moderate-income customers who use the most energy and who have the highest arrears. NS Power

1 *has data on customers with high arrears and high energy use (which are often*
2 *characteristics of lower-income households); NS Power could refer customers that are high*
3 *priority based on these criteria to E1 for further screening and follow-up. This targeting*
4 *will advance the resolution of payment troubles, improve affordability, and reduce fossil*
5 *fuel consumption.*

7 **E1 Rebuttal Evidence**

8 E1 agrees that providing support for low income and equity customers through strategic electrification
9 programs is important, however, fully funded programs present challenges to meeting cost effectiveness
10 thresholds and ultimately meeting the legislative requirement of reducing electricity costs. E1 further
11 notes that the 2024 report Ms. Napoleon relies upon, A Way Forward: A Made-In-Nova Scotia Home
12 Energy Affordability Program, is primarily directed at federal and provincial government-funded
13 programming rather than ratepayer-funded DSM. The targeting approach it recommends is therefore
14 framed in the context of government funding, and its recommendations do not account for the cost-
15 effectiveness and legislative requirements that constrain DSM programs funded by ratepayers.

17 **2.2 DEMAND RESPONSE**

18 Ms. Napoleon's evidence addresses the demand response program, including comments on (1) the cost-
19 effectiveness of the residential demand response program component, (2) the costs of that program
20 component, (3) calculations of peak load reductions and (4) Business, Non-Profit, and Institutional (BNI)
21 program component offerings. Ms. Napoleon's comments with respect to each of these matters, and E1's
22 responses thereto, are set out in the subsections that follow.

24 **2.2.1 COST-EFFECTIVENESS**

25 First, Ms. Napoleon expresses concerns about the cost-effectiveness of the residential demand response
26 programs based on the Program Administrator Cost (PAC) test. At page 33, lines 8 – 12 she states:

27 ***Q. Do you have any concerns about E1's demand response program proposal?***

28 *A. Yes. I identify major concerns regarding the following aspects of E1's demand*
29 *response proposal:*

- 30 • *E1's proposed residential demand response program offerings have PAC BCRs less*
31 *than 1.*

2.2.1.1 COST-EFFECTIVENESS TIMELINES

Synapse

In particular, Ms. Napoleon flags concerns that E1's statements on the projected cost-effectiveness of the residential demand response component are inconsistent and that the conclusion that the program will become cost-effective is not supported by evidence. At page 34, lines 12 – 22, Ms. Napoleon states:

However, E1's statements about the projected cost-effectiveness of the residential demand response component over the course of the plan period are not internally consistent. E1 states that "through direct discussions with the IESO Demand Side Management team, the [residential demand response] program is expected to reach cost-effectiveness under the Program Administrator Cost (PAC) test within the next year." Later in the evidence, E1 contradicts itself, claiming instead that the residential demand response program "is expected to achieve cost-effectiveness within the next two to three program seasons." Neither of these conclusions that the program is expected to become cost-effective is supported by E1's response to Synapse IR-62(b), which shows the residential PAC BCR ranging between 0.5 and 0.9 during the plan period, as detailed in Table 8 above.

E1 Rebuttal Evidence

With respect to Ms. Napoleon's comment that "E1's statements about the projected cost-effectiveness of the residential demand response component over the course of the plan period are not internally consistent",² E1 clarifies that its statement about reaching cost -effectiveness within one year referred to the Ontario IESO's Peak Perks program, not E1's residential demand response program component. As to Ms. Napoleon's observation that E1's response to Synapse IR-62(b) shows the residential PAC BCR ranging between 0.5 and 0.9 over the plan period, E1 notes that these modelled values reflect a program that remains in an early development phase, within which fixed start-up and enablement costs are spread over a comparatively small and growing participant base. E1 relied on current residential DR cost structure and participant performance information at the time of modelling residential DR for the 2027–2031 DSM Preferred Plan. E1 understands that there is additional residential DR potential in the market and that the resource is expected to help address future system capacity needs. E1 is focused on improving the cost -effectiveness of residential DR through the identification of alternative cost structures and optimized participant performance so that the resource is cost-effective before scaling is considered. The timing of

² E-23, page 34, lines 12 – 14.

those outcomes is uncertain and are therefore not reflected in the Plan's 2027–2031 DSM Plan cost-effectiveness estimates.

2.2.1.2 PATHWAYS WITH LOW MARGINAL COSTS OF CUSTOMER ENABLEMENT

Synapse

Ms. Napoleon recommends E1 enroll new participants in pathways with low marginal costs of customer enablement in order to reduce overall costs for the residential demand response program. At page 36, lines 12 – 16, Ms. Napoleon states:

Q. What do you recommend regarding enrolling new participants in the residential demand response program over the plan period?

A. E1 should seek opportunities to reduce overall costs per kW of capacity by enrolling new participants in pathways with low marginal costs of customer enablement.

E1 Rebuttal Evidence

E1 does not agree that the way to cost-effectiveness is to enroll new participants but rather to focus on program delivery costs and optimizing participant performance first to reach cost-effectiveness as a more prudent approach. Enrolling new participants prior to focusing on these areas, risks scaling a program component that maintains those challenges and remains not cost-effective.

2.2.1.3 HIGHER AVERAGE BENEFITS PER KW CAPACITY

Synapse

Ms. Napoleon also recommends E1 evaluate program design changes that could drive higher average benefits per kW capacity. At page 36, lines 17 – 24 of her evidence, Ms. Napoleon states:

Q. Do you have any other recommendations regarding the residential demand response PAC BCR?

A. Yes. Beyond seeking out opportunities to decrease average costs per kW of capacity, E1 should also evaluate program design changes that could drive higher average benefits per kW capacity. Such modifications could include revisions to pre-heating durations and setpoints, event setbacks, and event durations. E1 could also target the most constrained circuits to increase the benefits associated with avoided transmission and distribution costs.

E1 Rebuttal Evidence

E1 agrees with Ms. Napoleon’s recommendation and plans to implement changes in the upcoming 2027 DR season (pending NSEB approval) as part of improving program performance to achieve higher benefits. E1 intends to look at both program delivery costs and improving participant performance. E1 has also committed to assessing locational demand response opportunities by targeting the most constrained feeders but requires feeder data from NS Power. E1 has requested this data and NS Power has agreed to provide it.

2.2.2 RESIDENTIAL DEMAND RESPONSE DELIVERY COSTS

Second, Ms. Napoleon makes recommendations regarding residential demand response costs. At page 6, lines 7 – 13, Ms. Napoleon recommends:

Regarding residential demand response, E1 should seek opportunities to reduce overall costs per kW of capacity by enrolling new participants in pathways with low marginal costs of customer enablement. E1 should also conduct a process evaluation of the delivery of the residential demand response program to identify opportunities for gaining efficiencies and achieving cost reductions. Additionally, E1 should review its competitive procurement process for residential demand response delivery services.

2.2.2.1 COST-EFFECTIVE ADMINISTRATION & REASONABLE DELIVERY BUDGET

Synapse

Ms. Napoleon flags concerns about whether E1’s residential demand response programs are being administered cost-effectively and whether the proposed delivery budget is reasonable. At page 37, line 18 to page 39, line 4, she states:

Q. How do E1’s Residential program delivery costs compare to other jurisdictions?

A. E1’s proposed residential demand response delivery costs as a share of total budgets appear substantially higher than similar programs in other jurisdictions. The independent evaluator’s comparison shows that total non-incentive spending—inclusive of program delivery, program administration, marketing, and other costs—accounted for only 27 and 29 percent of residential demand response budgets for Rhode Island Energy and National Grid (Massachusetts), respectively. Meanwhile, E1 has proposed a budget consisting of 77 percent for total non-incentive spending, and 63 percent for program delivery alone. This finding raises concerns about whether E1’s residential demand response programs are

1 *being administered cost-effectively and whether the proposed delivery budget is*
2 *reasonable.*

4 **E1 Rebuttal Evidence**

5 E1 acknowledges that the delivery-cost share of its residential demand response budget is higher than
6 that of the Rhode Island Energy and National Grid (Massachusetts) programs cited by Ms. Napoleon, but
7 submits that the comparison does not establish that E1's proposed budget is unreasonable. As Ms.
8 Napoleon's own evidence recognizes, residential demand response is delivered through a large number of
9 smaller customer-side devices and therefore carries a higher delivery cost per unit of capacity than larger
10 resources, and E1's program component is at an earlier stage of development than the established
11 programs to which it is compared. The Rhode Island and Massachusetts programs benefit from mature
12 markets, higher device penetration, and larger participant bases over which fixed delivery costs are spread,
13 none of which is presently true of E1's residential program. A share-of-budget comparison across programs
14 at materially different stages of maturity, without normalization for scale, market conditions, and delivery
15 model, is not a sound basis for concluding that E1's delivery budget is unreasonable. Additionally,
16 benchmarking program costs is not a simplistic exercise. To appropriately benchmark program
17 administrator costs, one must fully understand how comparative utilities define and categorize the costs.
18 It is not clear to E1 how Rhode Island Energy and National Grid (Massachusetts) categorize their costs.
19 Only after this is understood can a meaningful assessment be conducted. E1 defines incentives as direct
20 customer incentives, third-party delivery costs and technology costs, which represent approximately 80%
21 of the residential demand response budget with 20% remaining for what E1 categorizes as non-incentive
22 costs.

24 2.2.2.2 E1'S RESIDENTIAL PROGRAM DELIVERY VENDORS

25 **Synapse**

26 Ms. Napoleon makes recommendations with respect to E1's residential program delivery vendors. At page
27 39, line 17 – 25 of her evidence, Ms. Napoleon states:

28 ***Q. What do you recommend regarding E1's residential program delivery vendors?***

29 *E1 should conduct a process evaluation of the delivery of the residential demand response*
30 *program to identify opportunities for gaining efficiencies and achieving cost reductions.*

31 *Process evaluations can also find opportunities to improve effectiveness, including lessons*
32 *from how other utilities deliver these programs. Additionally, E1 should review its*

1 *competitive procurement process for residential demand response delivery services to*
2 *ensure it enables E1 to choose from a pool of competitive bidders the most cost-effective*
3 *delivery solution.*

5 **E1 Rebuttal Evidence**

6 With regard to the recommendation that E1 conduct a process evaluation of the delivery of the residential
7 demand response program to identify opportunities for gaining efficiencies and achieving cost reductions,
8 E1's third party evaluator performed a process evaluation of the Residential DR program component as
9 part of the 2025 evaluation, filed on March 31, 2026. The 2027–2031 DSM Plan already provides for this
10 work: it proposes annual impact evaluations, with process and market evaluation timing to be determined,
11 a framework that already permits E1 to pursue delivery efficiencies and cost reductions where and when
12 they are most useful. An additional, separately mandated process evaluation is therefore not necessary,
13 even one focused on program delivery. Given that the cost of the recommended evaluation has not been
14 estimated, additional unquantified spending in this area is not warranted and risks diverting ratepayer
15 funds from program delivery contrary to the Plan's affordability focus.

16
17 With regard to the recommendation that E1 review its competitive procurement process for residential
18 demand response delivery services, E1 notes that for all E1 procurements, ensuring that there is an
19 adequate pool of competitive bidders has been a priority for the organization for several years. E1's current
20 procurement practices include a pre-market consultation process which is intended to ready the market
21 for an upcoming procurement; provides early notification to potential proponents of upcoming
22 procurements; and offers a streamlined submission process to reduce burden on proponents in
23 preparation of responses. Together all of these actions are intended to encourage uptake to ensure there
24 is an adequate pool of competitive bidders.

26 **2.2.3 PEAK LOAD REDUCTIONS**

27 **Synapse**

28 Third, Ms. Napoleon addresses calculations of peak load reductions. At page 6, lines 19 – 20, Ms. Napoleon
29 recommends:

30 *E1 should shift to assessing and weighting performance of demand response over the*
31 *entire duration of the event.*

At page 43, lines 16 – page 44, line 14, Ms. Napoleon states:

Q. Please explain how E1 proposes to assess demand response performance across the duration of demand response events.

A. E1’s evaluation of available demand response capacity is weighted toward the early hours of an event. E1 states that for its residential program it “evaluates available DR capacity based on demand reduction during winter event hours, primarily the first two hours of eligible events,” and “for Business, Non-profit and Institutional (BNI) DR, the same methodology is used.” Yet E1’s event data indicate that the residential and BNI events are consistently four hours long, and that residential capacity degrades by roughly half between the first and fourth hours (BNI hourly data is not available).

Q. Why does this misalignment matter?

A. If E1 dispatches four-hour events and claims savings on a four-hour basis but evaluates performance based primarily on the first two hours, the methodology overstates the performance of pathways for which the curtailment degrades over the event, most notably the thermostat and water-heater pathways. By comparison, the battery and EV pathways, which can sustain output across the full event, are made to look relatively worse than they are. I therefore recommend that E1 weight performance equally across all hours of each event. Equal weighting would produce a more accurate comparison across pathways and would strengthen the relative cost-effectiveness case for the battery and EV pathways. I also recommend further consideration of whether a four-hour event is the most appropriate duration, given NSPI’s electric system peak hours.

E1 Rebuttal Evidence

Ms. Napoleon in her recommendation is referencing E1’s response to Synapse IR-18 which described the evaluation approach for the 2023–2026 period. E1 in the 2027–2031 DSM Plan has proposed that available demand response capacity be measured and evaluated for the full four hour event³, not the first two hours as was the case in the 2023–2026 evaluation period.

2.2.4 BNI PROGRAM OFFERINGS

Synapse

³ Exhibit 1, 2027–2031 DSM Plan Application, Appendix A, page 103, lines 17-20.

Fourth, with respect to DR, Ms. Napoleon addresses BNI program offerings. At page 6, lines 21 – 23, Ms. Napoleon recommends:

E1 should develop differentiated incentives for its BNI demand response program, with higher incentives for battery-based BNI standby resources than for fossil-fueled generators.

At page 45, lines 1 – 7, Ms. Napoleon states:

Q. What do you recommend?

A. To address these local air-quality impacts and to fill a gap in E1's offerings (E1 has no BNI pathway dedicated to batteries) I recommend that E1 develop a higher incentive for battery-based BNI standby resources than for fossil-fueled generators. A differentiated incentive would encourage cleaner capacity, extend the battery pathway's benefits to the BNI sector, and reduce reliance on emitting generation during demand response events.

E1 Rebuttal Evidence

E1 does not support differentiated incentives between battery-based BNI standby resources and fossil-fueled generators at this time. E1 has taken a technology neutral approach to BNI demand response curtailment, recognizing they currently provide the same economic value to the grid. E1 may revisit this approach in the future should system needs, policy objectives, or market conditions change.

3. CONSUMER ADVOCATE EVIDENCE

Theodore Love of Green Energy Economics Group, Inc. provided evidence on behalf of the Consumer Advocate. Mr. Love's evidence was filed with the Board as E-21. This section sets out new evidence of E1, responding to new concerns raised in Mr. Love's evidence with respect to plan scenarios and savings targets, unit costs, pre-weatherization barriers, and residential heat pumps in the 2027–2031 DSM Plan. Rebuttal testimony provided by Apex Analytics is provided and attached as Appendix A and addresses several concerns raised in Mr. Love's evidence including savings targets, unit costs, and incentives.

3.1 PLAN SCENARIOS AND SAVINGS TARGETS

Consumer Advocate

Mr. Love takes issue with E1's approach to setting low-income and equity customer targets. At page 18, lines 15 – 20, he states:

Q. DO YOU HAVE ANY CONCERNS ABOUT THE E1'S UPDATED APPROACH TO SETTING LOW INCOME TARGETS?

A. Yes. My overarching concern is that E1 has set its targets for low-income and equity customers by reference to its own past performance rather than to the need in the population, and that the resulting target locks in historically low delivery to the customers who most need bill relief.

At page 20, lines 5 – 13, Mr. Love states:

E1 should anchor the savings target to the need of the community. In this case 14.9% of Nova Scotians are Low-Income, yet the Low-Income dedicated programs represent only an 11% share of residential savings, below their share of the residential population. E1's responses confirm that the Low-Income savings target is not grounded in needs. In response to CA IR-16(b), E1 stated that it "has not, to date, defined equity for residential low-income customers by reference to their proportionate share of residential load," and that it "is not aware that disaggregated residential load data attributable specifically to low-income customers exists." That is a data gap E1 should close; it is not a reason to default to a low, self-referential target.

At page 21, lines 1 – 5, Mr. Love further states:

Q. WHAT DO YOU RECOMMEND FOR A DEDICATED LOW-INCOME SAVINGS TARGET?

*A. I recommend that the **Low-Income savings target for dedicated programs should be set to 14.9% of the Residential Savings target**, currently 3.76 GWh in the Preferred Plan, in order to match the low-income percentage of the population.*

E1 Rebuttal Evidence

E1 respectfully disagrees that the dedicated low-income and equity savings target should be fixed at 14.9 percent of the Residential Savings target, being Mr. Love's proposed 3.76 GWh, because approximately 14.9 percent of Nova Scotians are low-income. A savings target must be grounded in what can realistically and cost-effectively be delivered, not in population share alone, and Mr. Love offers no analysis demonstrating that a 14.9 percent target is achievable. The Preferred Plan's dedicated low-income and

equity savings of approximately 11 percent of residential savings are consistent with the 2023–2026 level of approximately 10.5 percent. Critically, the record shows that the dedicated low-income and equity components already carry a PAC benefit-cost ratio below 1; mechanically scaling those components up to match population share would compound that cost-effectiveness shortfall and place additional upward pressure on rates, contrary to the near-term affordability objective that frames the Plan. As E1 confirmed in response to CA IR-16(b), disaggregated residential load data attributable specifically to low-income customers does not presently exist; that data gap is a reason for caution in setting such a target, not a basis for locking in an aspirational target that E1 may be unable to meet.

E1 also highlights that beyond dedicated low income and equity energy savings from energy efficiency, there are both dedicated solar-PV and incidental low income and equity savings in the Plan as well. The total dedicated low income and equity savings from energy efficiency and solar-PV for the residential sector are 12.4% of the residential sector savings (energy efficiency and solar-PV combined). Total dedicated and incidental low income and equity energy savings (energy efficiency only) are 22.7% of the residential sector savings, which far exceeds the 14.9% target suggested by Mr. Love.

E1 further notes that setting targets by reference to demonstrated, achievable delivery is a disciplined and defensible planning approach rather than an arbitrary one, and is consistent with the affordability and balanced-plan principles that frame the Preferred Plan. Mandating a materially higher dedicated low-income and equity target than E1 has historically been able to deliver risks stranded budget, spending pressure that must be recovered from all ratepayers, and pursuit of higher-cost savings, each of which is in tension with the near-term affordability objective.

3.2 UNIT COSTS

3.2.1 EXAMINATION OF MORE ECONOMICAL DELIVERY

Consumer Advocate

At page 29, lines 5 – 16, Mr. Love states:

If a heat pump now produces roughly half the evaluated savings it was previously credited with, the cost of acquiring each kWh through that measure has effectively doubled, and the appropriate response is for E1 to examine how to deliver the measure more economically rather than to treat the higher cost as fixed. That examination should include whether incentive levels can be reduced without losing participation, and whether the

1 *program design can be changed to raise the savings each installation actually delivers.*
2 *This could be accomplished by requiring a minimum heating switchover temperature, by*
3 *requiring removal or lock-out of backup electric resistance heating, or by tightening*
4 *eligibility so that incentives flow to installations that displace the most fossil or resistance*
5 *heating. E1 has not yet shown that it has pursued these levers. Until it does, the corrected*
6 *savings should be read as a reason to redesign the measure for greater cost-effectiveness,*
7 *not as an external cost increase that E1 is powerless to address.*

9 **E1 Rebuttal Evidence**

10 E1 accepts the 2024 evaluation savings for residential heat pumps as the appropriate baseline, but does
11 not accept the implication that it has treated the resulting higher cost per kWh as fixed or has failed to
12 pursue available program levers. E1's incentive levels are set using the Board approved incentive setting
13 methodology and are set in the 2027–2031 DSM Preferred Plan to cover approximately 10 percent of total
14 project cost in 2027 up to 15-20 percent in 2031 which remains lower than the 40 percent or greater
15 coverage that Apex Analytics suggested is typical in other jurisdictions. Program participation and results
16 during the 2023–2026 Plan have been influenced greatly by government incentives, which offered top up
17 incentives of roughly 40 percent or more of total project costs to DSM customers. With government
18 funding significantly decreasing with the conclusion of the Canada Greener Homes Grant, the current low
19 level incentive is not expected to continue to drive results in the 2027–2031 Plan (please see E1's response
20 to Synapse IR-37 for more information).

21
22 E1 is exploring a more economical delivery method in the form of mid-stream rebates through the Instant
23 Savings program component starting in 2028 but this cannot fully displace the Home Energy Assessment
24 model. It is important to also continue to offer energy assessments through Home Energy Assessment to
25 customers who need more education and decision-making support. Energy evaluations help ensure
26 heating systems are properly sized and that the impacts of other upgrades being planned are taken into
27 consideration.

28
29 E1 supports customers with diverse needs and many different heating system and fuel configurations
30 making it challenging to implement controls that lock out backup heating systems based on temperature.

With respect to Mr. Love's specific suggestions, a mandatory minimum heating switchover temperature and the removal or lock-out of backup electric resistance heating raise real customer-comfort, safety, and reliability considerations in Nova Scotia's cold climate, and tightening eligibility carries a risk of suppressing participation among the very customers the program is intended to reach.

3.2.2 MEASURE-SPECIFIC PRIMARY RESEARCH

Consumer Advocate

At page 34, lines 1 – 8, Mr. Love makes the following recommendation:

Q. WHAT DO YOU RECOMMEND REGARDING WAYS TO RESTRAIN SAVINGS ACQUISITION COSTS?

A. I recommend that the Board: direct E1 to undertake measure-specific primary research (e.g., price-sensitivity or conjoint analysis) for high-value measures, consistent with the thresholds the CLEAResult methodology already contemplates, to confirm that incentive levels are set at the minimum necessary to secure participation. This research should then be used to inform updates to incentive no later than January 1, 2028.

E1 Rebuttal Evidence

E1 agrees that incentives should be set no higher than necessary to secure participation, and as such applies the Board approved incentive setting methodology. In preparation for the 2027–2031 Plan, E1 engaged Apex to assess its incentive-setting methodology against comparable jurisdictions and to recommend possible improvements to E1's internal processes. E1's responses to the APEX recommendations were provided in response to IG IR-11. E1 submits that a Board directive to undertake measure-specific primary research, such as price-sensitivity or conjoint analysis, for high-value measures and to reset incentives no later than January 1, 2028, is neither necessary nor practical. Such primary research is costly and time-consuming to design and field, the results are measure- and time-specific and can quickly become stale, and the expense may be disproportionate to the benefit for a portfolio of this size, ultimately drawing funds away from program delivery contrary to the Plan's affordability focus. A fixed January 1, 2028 deadline, as proposed by Green Energy Economics Group, also fails to appropriately consider the lead time required to scope, procure, and complete credible primary research.

E1 further notes that Green Energy Economics Group accepts that incentives should be set no higher than necessary to secure participation, and acknowledges that the loss of low-cost LED lighting partly explains

1 rising program unit costs. The dispute is therefore narrow. E1 already applies the Board-approved
2 incentive-setting methodology to ensure incentives are no higher than necessary, and as shown in E1's
3 response to IG IR-11, Attachment 2, E1's measure incentives sit at or below the recommended thresholds
4 under that methodology. A new, externally-imposed program of measure-specific primary research on a
5 fixed January 1, 2028 timeline is not necessary to achieve an objective that E1's existing methodology
6 already serves.

8 3.3 PRE-WEATHERIZATION BARRIERS

9 Consumer Advocate

10 At page 35, lines 3 – 11, Mr. Love states:

11 ***Q. HOW CAN E1 CLOSE THIS DATA GAP?***

12 *A. E1 should record, for each dedicated low-income and equity program component, the*
13 *number and proportion of customers who do not proceed because of pre-weatherization*
14 *barriers, the nature of those barriers, and the disposition of each case. E1 already conducts*
15 *the site visits at which this information arises, as its Service Providers “assess homes for*
16 *upgrade readiness during site visits and identify potential remediation solutions”, so*
17 *capturing the result of that assessment is a recordkeeping change, not a new program*
18 *cost. This data is a prerequisite to better understanding the challenge and refining the*
19 *approach for future plans.*

21 E1 Rebuttal Evidence

22 E1 does currently track projects that cannot proceed because upgrades are not possible or the homeowner
23 can no longer be reached.

25 3.4 RESIDENTIAL HEAT PUMPS

26 3.4.1 2027 VS 2028 START DATE

27 Consumer Advocate

28 At page 42, line 10 – page 43, line 9, Mr. Love states:

29 ***Q. WHY IS E1 STARTING THESE MEASURES IN 2028?***

30 *A. In its response to Synapse IR-43, E1 states that it is delaying the launch of these*
31 *measures until 2028 because “certain activities cannot reasonably proceed until approval*

of the Plan has been obtained, including the establishment of industry partnerships, the development of related program processes, and partner training.”

Q. DO YOU AGREE WITH E1’S JUSTIFICATION FOR WAITING UNTIL 2028 TO PROVIDE THESE REBATES?

A. No. Mini-split and centrally ducted HPs are not a new technology to E1. Both of these measures are already offered as installed measures under the Affordable Single-family Homes program and as rebated measures under the Business Energy Rebates program. E1’s Efficiency Preferred Partner network already includes heat pump installers. The incremental work of extending point-of-sale rebates to the Instant Savings program does not require building new industry relationships from scratch. E1’s own response to Synapse IR-43 acknowledges this, as it states that “[E1] is undertaking preparations for implementation of DSM programs for the 2027–2031 period” even before approval. There is no structural reason why Instant Savings partnership agreements for heat pumps cannot be negotiated on a conditional basis before the decision issues. Even if there is a six-month delay in offering rebates, E1 should still be able to have them ready for the 2027 heating season.

E1 Rebuttal Evidence

E1 maintains that a 2028 launch for the point-of-sale heat pump rebate measures is reasonable and prudent. While mini-split and centrally ducted heat pumps are offered under other E1 programs and E1’s Efficiency Preferred Partner network includes heat pump installers, extending point-of-sale rebates to the Instant Savings program component is not simply a matter of leveraging existing relationships: it requires establishing new partner agreements and point-of-sale processes, developing program processes, and training partners, and certain activities cannot reasonably be finalized or committed to before the Plan is approved. Negotiating Instant Savings partnership agreements on a conditional basis before a decision is issued carries commercial and reputational risk, and would require E1 to expend ratepayer resources on arrangements that may need to be unwound if the Plan is not approved as filed.

3.4.2 INCENTIVES

Consumer Advocate

At page 43, line 19 – page 44, line 18, Mr. Love states:

Q. DO YOU HAVE ANY OTHER CONCERNS WITH E1'S APPROACH TO MINI-SPLIT AND CENTRALLY DUCTED HPS IN THE RESIDENTIAL SECTOR?

A. Yes. I am concerned that E1 is increasing incentives unnecessarily in its current plan. E1 has not provided any justification for increasing incentives by between 67% and 80% over four years for a measure that it has yet to have launched and without any updated potential study. Given the importance of affordability and the rising unit costs projected for the portfolio, this level of increase needs at least some justification.

Q. IS THERE ANY PROGRAMATIC RATIONALE UNDER WHICH ESCALATING INCENTIVES MIGHT BE APPROPRIATE?

A. In some circumstances, escalating incentives are appropriate. For example, when a program is targeting progressively harder-to-reach customers after the most cost-effective participants have been served, or when early-adopter customer segments are more self-motivated and late-adopters require more financial push. However, E1 has not made this argument, and these would be new incentives for a market that has not yet had aggressive DSM intervention. In addition, E1 projects a drop off in participation as the rebates reach their highest level in the final year. It is not clear why offering a higher incentive would lead to lower participation.

Another reason incentives may be increased is to address high freeridership rates. As incentives are increased, the first cost barrier to participate is lowered, and more of the population that was unable to participate due to this barrier can now take advantage of the opportunity, which would lower freeridership rates. Again, net-to-gross ratios are projected to stay the same for the period, negating any projected effect on freeridership from raising incentives.

Mr. Love recommends as follows at page 45, line 1 – 7:

- **Direct E1 to keep incentives for mini-split and centrally ducted HPs at \$500 and \$900 respectively in the Instant Savings and HEA programs. This will keep acquisition costs lower and allow budgets to stretch further. These measures should be included in the updated analysis I am requesting E1 undergo to establish a more solid basis for setting incentives moving forwards. If participation lags, or freeridership rates become an issue, E1 can modify incentive levels as part of an MCA.**

E1 Rebuttal Evidence

E1 submits that having the Board direct E1 to cap incentives over the five-year period to the levels proposed by Mr. Love would limit E1's ability to adapt to changing product costs, fluctuating free ridership levels and savings, or other market conditions if needed to deliver the proposed results. If incentive levels were prescribed as recommended by Mr. Love, E1's ability to meet the savings levels proposed would be limited putting achievement of performance targets at risk.

Current heat pump incentives are considered low at approximately 5-10 percent of total project cost and are at risk of higher levels of free ridership, which negatively impacts the savings E1 can claim from the programs. This is confirmed by E1's response to IG IR-11, Attachment 2, which compares all of E1's measures and incentives against the recommended thresholds under the Incentive Setting Methodology: the heat pump incentives under the Home Energy Assessment program component are significantly lower than what that methodology recommends. E1 proposes to increase the Home Energy Assessment heat pump incentives from \$600 in 2027 and 2028, to \$900 in 2029 and 2030, to \$1,200 in 2031, and even at that peak the 2031 incentive represents only approximately 19 percent of project costs, well below the recommended threshold range of 30 percent to 100 percent Mr. Love's recommendation to freeze incentives at \$500 and \$900 would hold them even further below the recommended range, and Mr. Love has provided no methodological basis or evidence to support his recommended levels. E1 also notes that Mr. Love acknowledges escalating incentives can be appropriate to address free ridership, which is precisely one of the concerns E1's gradual escalation is designed to manage.

4. NOVA SCOTIA POWER EVIDENCE

NS Power engaged The Brattle Group ("Brattle") to review E1's Preferred Plan and assess its proposed 2027–2031 DSM Plan. The Brattle evidence was filed with the Board as E-22. This section sets out new evidence of E1 responding to new concerns raised in the Brattle evidence regarding DR, SE, and solar-PV in the 2027–2031 DSM Plan.

4.1 DEMAND RESPONSE

At PDF page 9, Brattle states:

1 *If DR is to receive increased investment, it should be subject to clearer performance*
2 *obligations, more transparent cost-per-kW metrics and stronger measurement and*
3 *verification.*

4
5 These matters, and relevant rebuttal evidence from E1 in response thereto, are explored in the subsections
6 below.

7
8 **4.1.1 RISK OF BNI**

9 At PDF page 13, Brattle states:

10 *Yet E1's Preferred Plan would leave residential DR participation declining and would rely*
11 *almost entirely on a small increase in BNI participation for incremental capacity. This*
12 *approach not only leaves a significant source of residential DR participation untapped but*
13 *also heightens the risk profile of BNI DR impacts as PRMs decline rapidly, given the lack of*
14 *class-level resource diversification within the DR portfolio.*

15
16 **E1 Rebuttal Evidence**

17 E1 notes at the outset that Brattle does not dispute that the Preferred Plan grows total Demand Response
18 capacity by approximately 80 percent over the plan term, from 16.3 MW in 2026 to 29.3 MW in 2031. The
19 Preferred Plan concentrates that incremental capacity in the BNI segment because BNI Demand Response
20 is strongly cost-effective, with a PAC result of 2.4, whereas residential Demand Response remains not
21 independently cost effective, with a PAC result of 0.7. In a plan expressly framed around affordability and
22 near-term ratepayer protection, directing incremental investment toward the most cost-effective,
23 verifiable capacity is the prudent course, not a weakness. Brattle's suggestion that BNI concentration
24 "heightens the risk profile" of the DR portfolio is asserted rather than quantified: Brattle offers no analysis
25 of the magnitude of that risk, no evidence that BNI availability or performance has been unreliable, and
26 no comparison of the reliability of BNI-sourced capacity against the residential capacity it would substitute.

27
28 While incremental Demand Response growth is concentrated within the BNI program component, the
29 portfolio itself is diversified across customers, sectors, facilities, and curtailable end uses rather than
30 relying on a single participant or technology.

1 In addition, the relatively small participant base allows E1 and its delivery partner to work closely with
2 individual customers, conduct test events, verify event readiness, and align participation with customer
3 operating preferences whether that be morning or evening participation. These practices support
4 participant retention, performance, and reliability.

5
6 E1 does not consider the reliance on BNI participation for incremental capacity to be a unique or material
7 risk. Like all DSM programs, Demand Response involves operational risks that must be actively managed.
8 E1 has established processes to manage these risks inclusive of the assignment of account managers for
9 participants, real-time event visibility and ongoing pre and post event customer engagement and has
10 demonstrated an ability to adapt program design and participant engagement as the portfolio has
11 matured. In the absence of evidence that additional residential Demand Response investment would
12 provide greater reliability or value for ratepayers, E1 considers continued growth through the more cost-
13 effective BNI pathway to be the prudent approach.

14 15 4.1.2 PROGRAM COSTS

16 At PDF page 17, Brattle states:

17 *First, current PAC test results assumes that program costs are appropriate, but residential*
18 *DR program costs are much higher compared to DR programs from other utilities, shown*
19 *in Figure 3. These high costs result in a low PAC ratio, even compared to E1's own BNI*
20 *programs. Costs for residential thermostat programs are \$577/kW-year by 2031 while BNI*
21 *curtailment programs only cost \$172/kW-year. E1 flags that "Residential DR is delivered*
22 *through a large number of smaller customer-side devices...As a result, residential DR has*
23 *a higher delivery cost per MW than larger BNI resources." While true that residential DR*
24 *will require outreach to a greater share of smaller customers, lower DR program costs for*
25 *other utilities indicate that there may be opportunities for cost reduction. Implementation*
26 *costs could decrease if E1 learned from their prior challenges, improved their*
27 *administration of the DR program, and took best practices and lessons learned from other*
28 *utilities with more robust established DR programs.*

FIGURE 3: UTILITY COSTS OF DEMAND RESPONSE (\$/KW-YEAR)



Source and Notes: Axis has been rescaled for visualization. Specian and Aquino, *Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth*, Table C3, p. 95.; EfficiencyOne, *2027–2031 DSM Resource Plan Application*, Appendix A, Table 8, p. 28.

E1 Rebuttal Evidence

With respect to Brattle's observation that residential Demand Response program costs are high relative to other utilities and to E1's own BNI programs, E1 notes that Brattle acknowledges the structural reason for the difference: residential DR is delivered through a large number of smaller customer-side devices and therefore carries a higher delivery cost per MW than larger BNI resources. Brattle's cost comparison aggregates programs across jurisdictions with materially different market maturity, device penetration, delivery models, and program vintages, and does not normalize for those differences or for the fact that E1's residential program remains in an early development phase in which fixed start-up costs are spread over a comparatively small participant base. The existence of lower per-kW costs elsewhere identifies a direction for improvement, which E1 intends to pursue, but it does not establish that E1's current costs are imprudent. E1 also notes that identifying alternative cost structures is one of the activities E1 has stated it is pursuing to improve the cost-effectiveness of its residential demand response program component and is therefore aligned with Brattle in this regard. E1 deems it prudent to pursue this activity prior to scaling future residential demand response activities to ensure it is not scaling these challenges.

4.1.3 INACTION LEADING TO COST-EFFECTIVENESS

NS Power

At PDF Page 17, Brattle states:

Finally, E1's logic for limiting residential DR in the Preferred Plan is internally inconsistent in that E1 states residential DR is important but then pauses expansion until cost-effectiveness improves. This effectively assumes that inaction will somehow result in a higher PAC test result and therefore a more cost-effective DR portfolio. E1 notes that

1 *discussions with Ontario IESO's Demand Side Management Team "highlight[ed] a number*
2 *of parallels relevant to E1's Residential Eco Shift program, including the time required to*
3 *achieve sufficient participant scale; [and] the importance of improving participation rates*
4 *and event performance over successive program seasons. Through these discussions, E1*
5 *concluded that their Eco Shift program "is expected to reach cost-effectiveness under the*
6 *Program Administrator Cost test within the next year". However, the IESO commentary*
7 *explicitly highlights the need for continued investment into the program over successive*
8 *programmatic seasons each year rather than stagnation of the program until it becomes*
9 *cost-effective by itself. And this is exactly how the IESO's Peak Perks program gained*
10 *momentum as we discuss in more detail below.*

12 **E1 Rebuttal Evidence**

13 E1 clarifies that E1 did not conclude that its Residential DR program component would reach cost
14 effectiveness in one year. This is a reference to the Ontario IESO's response to their Peak Perks program.
15 E1 does not contend that inaction produces cost-effectiveness. The Preferred Plan maintains, rather than
16 abandons, the residential program component and continues investment across successive program
17 seasons so that participation, event performance, and cost-effectiveness can improve over time,
18 consistent with the IESO experience Brattle cites. Notably, Brattle's own position confirms that scale alone
19 is not the answer: in response to E1 IR-05(b), Brattle acknowledged that it "is not able to provide an
20 estimate for the number of customers which would lead to a cost effective PAC test," and that "program
21 scale is not the only sufficient requirement for the cost-effectiveness under the PAC."⁴ That is precisely
22 E1's approach - to identify alternative cost structures and optimize participant performance to improve
23 cost-effectiveness before scaling - which aligns with the program improvements Brattle recommends
24 elsewhere in its evidence. Brattle reads the IESO commentary as requiring aggressive year-over-year
25 scaling, but "continued investment into the program over successive programmatic seasons"⁵ is equally
26 consistent with sustained, disciplined investment at a level calibrated to affordability constraints. Critically,
27 Brattle's own evidence shows that the IESO's Peak Perks program was enabled by a \$342 million ministerial
28 increase to Ontario's Conservation and Demand Management budget and was "forecast to be

⁴ E-31, NSPI (E1) RIR-5, page 2 of 2, lines 1 – 3.

⁵ E-22, PDF page 18.

approximately cost-effective at launch,"⁶ with cost-effectiveness assessed on a forward-looking, portfolio basis. E1's residential Demand Response, by contrast, is below the PAC test and is being advanced within a deliberately flat, affordability-constrained budget. The Ontario precedent therefore does not support obligating E1 to scale a program that is not cost effective in a very different funding environment.

4.1.4 LESSONS FROM PEAK PERKS

NS Power

At PDF pages 18 - 19, Brattle states:

Here are some of our observations on Peak Perks and what could be adopted by E1:

1. **Peak Perks provides a clear, immediate, and material incentive:** the offer is easy to understand: \$75 at enrollment and \$20 each year the customer stays enrolled. That matters because residential DR participation is often limited by attention, not just economics. The evaluation survey found that the prepaid Mastercard and energy-cost savings were the leading motivations, 80% selected them as top motivation/benefit drivers.
2. **Low-friction "bring your own thermostat" design:** Peak Perks does not require customers to move to a new rate, monitor wholesale conditions, or manually curtail load. Customers enroll an eligible Wi-Fi thermostat, and the response is automated. Eligibility also uses equipment many higher-usage households already have in the form of central air conditioning or a heat pump controlled by an eligible smart thermostat.
3. **Strong use of thermostat-manufacturer channels:** A major reason enrollment scaled quickly is that Ontario IESO and its implementer reached customers through the channels they already use, such as thermostat apps, emails, and device notifications. The evaluation found that 80% of participants enrolled through their smart thermostat application, and EnergyHub attributes the rapid scale-up partly to multi-channel enrollment and retention campaigns through thermostat original equipment manufacturer (OEM) partners.
4. **Customer control and comfort protections:** The program avoided the classic DR backlash problem by making events limited and reversible. Save on Energy says

⁶ Ibid, PDF page 19.

1 *the thermostat may pre-cool before an event, is adjusted by no more than two*
2 *degrees Celsius, lasts up to three hours, returns automatically afterward, and*
3 *customers can opt out at any time. The evaluation found most surveyed*
4 *respondents reported little to no comfort impact, and most rated comfort during*
5 *events above 7 out of 10.*

6 5. **Provincial scale and a simple public-good message:** *Peak Perks combined private*
7 *benefits with a civic reliability message: get paid, reduce consumption, help the*
8 *grid, and support reliable and affordable energy. This likely improved acceptance*
9 *because the customer action is small, automated, and framed as helping the*
10 *province during stressful grid conditions.*

11 12 **E1 Rebuttal Evidence**

13 Several of the design features Brattle enumerates, including a simple enrollment incentive, automated
14 "bring your own thermostat" participation, thermostat-manufacturer enrollment channels, and customer
15 comfort protections, are features already incorporated into the existing Eco Shift program. E1 has
16 recognized improvements in these areas during implementation in the 2023–2026 DSM Plan.

17 18 **4.1.5 “PASSIVE” ENERGY EFFICIENCY**

19 **NS Power**

20 At PDF page 20, Brattle states:

21 *A mature market needs to be actively developed, so passively waiting for the market to*
22 *mature by itself will not result in the best outcome. If E1 does not invest in better residential*
23 *DR delivery, stronger customer acquisition, cleaner technology integration, and more*
24 *rigorous performance measurement in this DSM cycle, there is little reason to expect the*
25 *facts to look materially better in the next one.*

26 27 **E1 Rebuttal Evidence**

28 E1 agrees that a Demand Response market must be actively developed. The Preferred Plan does so
29 through sustained investment, and ongoing refinement of delivery and measurement – aligned with
30 Brattle’s recommendation. Brattle’s characterization of E1’s approach as "passively waiting" misstates the
31 record: maintaining and improving a program through performance optimization across successive
32 seasons within a disciplined budget is active development, not stagnation. Brattle offers no evidence

1 establishing the specific level of investment required for the Nova Scotia residential DR market to
2 "mature," and its contrary assertion is not quantified against Nova Scotia's customer base, device
3 penetration, or system conditions.

4 5 **4.1.6 DEMAND RESPONSE REPORTING**

6 At PDF page 21, Brattle states:

7 *Finally, E1 should be required to report DR performance in a way that allows the resource*
8 *to be used in system planning and operations. That means annual accreditation and*
9 *performance reporting after each peak season, opt-outs, attrition, device failures,*
10 *customer compensation, delivery costs, and verified peak reduction.*

11 12 **E1 Rebuttal Evidence**

13 E1 supports transparent, meaningful reporting on Demand Response performance and already reports on
14 the program through its Annual Progress Reports and annual evaluation reports. This reporting already
15 includes:

- 16 • opt-outs – participation rates are reported in BNI evaluation;
- 17 • enrolled devices – reported in the annual evaluation;
- 18 • attrition – participation history (number of participants) over time is reported in the evaluation
19 reports;
- 20 • device failures – device failure issues are discussed in both the Annual Progress Report and annual
21 evaluation reports;
- 22 • customer compensation – enrollment and participation incentives are described in the annual
23 evaluation reports;
- 24 • delivery costs – total spending on the residential and BNI DR program components is reported in
25 the quarterly and annual progress reports;
- 26 • verified peak reduction – available capacity for demand response aligned with the Performance
27 Target metric is reported in both the Annual Progress Report and the annual evaluation reports;
28 and
- 29 • capacity value – available capacity, and new capacity for the program components are reported in
30 the Annual Progress Report and annual evaluation reports; unitary available capacity per device
31 and/or per participant are reported in the evaluation reports.

E1 is uncertain of the costs and requirements associated with a separate accreditation report. If such additional reporting is warranted or would provide additional value, then E1 would assess the best approach to balance costs and value. E1 remains committed to ensuring that reporting supports the IESO Nova Scotia’s system planning efforts and NSEB oversight.

4.2 STRATEGIC ELECTRIFICATION

At PDF page 9, Brattle states:

E1 has excluded SE as a DSM resource in the Preferred Plan because the modelled measures did not satisfy the Board-approved modified PAC test, including the requirement that SE reduce both greenhouse gas (GHG) emissions and electricity costs for customers. Brattle’s assessment is that this conclusion should not end the inquiry, because E1’s program designs may not have fully incorporated the design features most likely to make SE beneficial, such as hourly modeling of impacts, flexibility, load controls, managed electric vehicle (EV) charging, or targeted deployment features. Rather than leaving SE as a research-only activity throughout the 2027–2031 plan term, the Board should require E1 to develop a phased pathway that identifies stronger candidate measures, improves data collection and cost-effectiveness modeling, and redesigns programs to better align electrification with system planning needs.

These issues, and E1’s rebuttal evidence with respect thereto, are explored in the subsections below.

4.2.1 DATA

NS Power

At PDF page 24, Brattle states:

For instance, it is very important to model the impact of SE measures on an hourly basis, as the “strategic” or beneficial aspect of SE programs are about not adding incremental load during the peak hours.

At PDF page 31, Brattle also states:

We recommend that the Board requires E1 to develop a phased SE pathway that identifies candidate measures with stronger cost-effectiveness potential, improves the underlying

1 *data used in benefit-cost analysis, and tests programs designed around real system value.*
2 *In particular, E1 should model SE using hourly data granularity and prioritize measures*
3 *that avoid or reduce peak impacts, shift load to lower-cost hours, use passive or direct load*
4 *control, and target areas of the distribution system with available capacity.*

6 **E1 Rebuttal Evidence**

7 E1 agrees that hourly modelling and improved data are valuable, and the Preferred Plan already commits,
8 through the Enabling Strategies budget, to market research and technology assessment, pilot programs,
9 collaboration with IESO Nova Scotia on future IRP development, and continued refinement of avoided-
10 cost and capacity-value inputs, precisely the data-improvement work Brattle recommends. During past
11 DSM Advisory Group discussions on avoided costs with NS Power, E1 has provided written comments on
12 their support for more granularity in the energy avoided costs specifically for time-varying avoided costs
13 using at a minimum 4-time blocks. Importantly, Brattle itself concludes that, given Nova Scotia's statutory
14 constraints, "there is not a robust path for comprehensive strategic electrification in Nova Scotia at this
15 time."⁷ Better data and hourly granularity may sharpen future modelling, but they do not overcome the
16 structural feature of the modified PAC test that Brattle identifies.

17
18 E1 also notes that its assessment was not limited to a narrow set of electrification measures. During
19 portfolio development, E1 modelled a broad range of residential and commercial strategic electrification
20 opportunities, including heat pumps, heat pump water heaters, hybrid heating solutions, and custom
21 applications. For certain measures, E1 also evaluated highly favourable scenarios that assumed zero peak
22 demand impacts. Even under those best-case assumptions, the measures did not satisfy the modified PAC
23 test. As a result, while hourly modelling and improved data may refine future analysis, E1's findings suggest
24 that it is unlikely the impact of these would change the outcome of the modified PAC substantially. E1's
25 phased, research-and-pilot approach within Enabling Strategies is therefore a reasonable response to the
26 current statutory framework, and E1's continued data-development work will position it to reassess SE as
27 avoided costs and capacity values evolve.

29 **4.2.2 FLEXIBILITY**

30 At PDF page 24 – 25, Brattle states:

⁷ E-22, PDF page 31.

1 *Successful cost-effectiveness outcomes within the existing Board-approved framework can*
2 *be achieved by designing proposed electrification programs around flexibility such that*
3 *they eliminate or reduce the peak impacts. These benefits can be realized by shifting loads*
4 *away from higher-cost hours; encouraging peak demand reduction during system critical*
5 *conditions through passive or direct control; or targeting deployment to unconstrained*
6 *parts of the distribution system. For instance, an EV managed charging program, or*
7 *electric water heating program which can shift the load to off-peak hours, could improve*
8 *grid utilization and defer expensive incremental grid investment. Integrating flexibility into*
9 *the design of SE programs is particularly relevant because E1's own application recognizes*
10 *that demand response and flexible demand-side resources will become increasingly*
11 *important as the electricity system evolves in response to electrification, environmental*
12 *compliance, and changing market conditions. Therefore, to the extent that program*
13 *design puts SE at a disadvantage, E1 must re-design these programs to emulate those that*
14 *are proven to provide system benefits.*

15
16 *These points are important because E1 appears to have evaluated SE primarily as a set of*
17 *building electrification measures and then excluded the entire resource category based on*
18 *modified-PAC results. E1 should be required to develop a more targeted building*
19 *electrification program focused on measures with the best chance of meeting Nova*
20 *Scotia's statutory criteria of reducing costs by incorporating more directly controllable*
21 *electric load, displacement of high-emitting fossil fuels, and integration with*
22 *weatherization and building controls, and even prioritizing electrification in parts of the*
23 *grid with headroom for distribution capacity. If E1's SE programs help increase load*
24 *without driving up further capacity costs both in generation, and T&D, then the existing*
25 *fixed costs of the grid could be spread over a larger number of MWhs, reducing the*
26 *electricity costs for customers. This structure would increase the likelihood that these*
27 *programs satisfy the statutory requirement to reduce both electricity costs and emissions.*

28
29 *For these reasons, E1's conclusion that SE cannot be included as a resource under the*
30 *current plan should not end the inquiry. The Board need not require E1 to fund uneconomic*
31 *SE measures under the current modified PAC framework. However, the Board should also*
32 *not allow SE to remain a research-only activity for the full 2027–2031 plan term. At a*

1 *minimum, the evidence supports requiring E1 to develop a phase-in pathway that*
2 *identifies more effective candidate measures including integrated flexibility and load*
3 *control features while continuing to refine its data gathering process for the purposes of*
4 *cost-effectiveness calculations.*

5 *[emphasis added]*

6 In addition, at PDF page 31, Brattle states:

7 *E1 should also redesign its SE portfolio to focus on measures most likely to satisfy Nova*
8 *Scotia's statutory requirement to reduce both electricity costs and emissions. For building*
9 *electrification, this means emphasizing measures that combine fossil-fuel displacement*
10 *with flexible load, weatherization, building controls, and targeted deployment in*
11 *unconstrained parts of the grid.*

13 **E1 Rebuttal Evidence**

14 E1 shares Brattle's interest in flexibility, load control, and targeted deployment, and will continue to
15 incorporate these features into its SE research and pilot work. However, the premise that redesigning SE
16 programs around flexibility will render them cost-effective under the modified PAC test is not borne out
17 on the record. As E1's application explains, and as Brattle acknowledges elsewhere in their evidence, the
18 modelled SE measures remained not cost-effective "even under optimal assumptions where there are no
19 peak impacts arising from the strategic electrification measures..."⁸ That is because the modified PAC test
20 credits SE with only one benefit, incremental utility revenue, while treating the associated energy,
21 generation-capacity, and transmission and distribution avoided costs as negatives; flexibility measures that
22 reduce or eliminate peak impacts address the cost side, improving modified-PAC results, but cannot
23 manufacture the revenue benefit needed to pass. E1 therefore has committed to pursue flexible, targeted
24 SE design in its phase-in work, but cautions against treating program redesign as a reliable route to cost-
25 effectiveness under the current statutory test.

27 4.2.3 CONSIDERATION OF TRANSPORTATION ELECTRIFICATION MEASURES

28 **NS Power**

29 At PDF page 25 - 26 Brattle states:

⁸ Exhibit E-1, 2027–2031 DSM Resource Plan Application, Evidence, page 35, lines 8-9.

1 *Crucially, the Board must also require E1 to consider transportation electrification*
2 *measures into any proposed set of strategic electrification programs. Managed EV*
3 *charging programs, both passive and active, have been shown to be effective at mitigating*
4 *distribution system constraints and deferring incremental investment, thereby applying*
5 *downward rate pressure in the near term. For instance, Newfoundland Power’s 2021–2025*
6 *Electrification, Conservation and Demand Management Plan recognized the benefits of*
7 *managed EV charging. The plan notes that “demand management is essential to realizing*
8 *the full benefits of EV adoption” as unmanaged charging has the potential to contribute*
9 *to capacity-related system cost. The plan also shows that managed charging passes the*
10 *cost-effectiveness test while unmanaged charging fails it. Therefore, there is evidence from*
11 *at least one other Canadian jurisdiction that the incorporation of managed EV charging*
12 *programs can enhance the cost-effectiveness of a broader electrification portfolio.*

13
14 At PDF page 32, they also state:

15 *Crucially, E1’s phase-in work should include transportation electrification, particularly*
16 *managed EV charging. Passive or active charging management can mitigate distribution*
17 *constraints, defer system investment, and improve the cost-effectiveness of broader*
18 *electrification portfolios.*

19 **E1 Rebuttal Evidence**

20
21 E1 did not include Strategic Electrification in the 2027–2031 DSM Preferred Plan because no programs or
22 measures were identified during plan development that satisfy the legislated definition of Strategic
23 Electrification and pass the Energy Board-approved modified PAC test. E1 agrees that transportation
24 electrification may be an important strategy for achieving provincial decarbonization goals but must
25 consider what initiatives are appropriately funded by electric ratepayers. Transportation electrification
26 measures, including EV purchase rebates, are load-increasing measures. As with other strategic
27 electrification initiatives, such measures face structural challenges under the modified PAC test. While
28 managed or off-peak charging can reduce capacity and transmission and distribution cost impacts
29 associated with increased electricity consumption, it does not eliminate the underlying system costs
30 associated with incremental load growth. Under the current modified PAC test, these costs are not fully
31 offset, which limits the ability of transportation strategic electrification measures to achieve positive
32 modified PAC test results. Accordingly, E1 considers EV demand response and managed charging to be

more appropriately explored in the DSM plan through the Innovation framework included in the Preferred Plan, where uncertainties regarding costs, customer participation, and system benefits can be further evaluated.

E1 agrees with Brattle Group that managed EV charging has the potential to provide system benefits relative to unmanaged charging, including reducing peak demand and deferring infrastructure investment. However, E1 submits that additional Nova Scotia-specific analysis is required before conclusions can be drawn regarding the applicability and cost-effectiveness of such programs. During development of the DSM Plan, E1's Innovation team engaged with Newfoundland Power to better understand the lessons learned from its EV load management programs. Based on Newfoundland Power's experience, it was estimated that 10 percent of the total EV market could be reasonably expected to participate in a demand-response program. Newfoundland Power identified EV owner behaviour, rather than technology, were key barriers to achieving greater levels of enrollment and demand-response event participation. E1's own experience similarly indicates that customer participation is a significant consideration. The 2025 Demand Response Evaluation Report found an average participation rate of 2.9 percent⁹ during the 2024–2025 season, corresponding to an average opt-out rate of 97.1 percent across demand response events. While managed charging programs differ from the Eco Shift EV demand-response program, these findings indicate that customer participation and vehicle availability may be important factors influencing realized peak demand reduction benefits. E1 has also engaged with original equipment manufacturers of EV chargers and understands that managed charging solutions typically rely on smart chargers that carry a premium and on-going subscription cost. To shift the EV market to smart chargers these additional costs would also need to be considered alongside E1's existing Eco Shift program costs, which is not currently cost-effective under the PAC. For these reasons, E1 considers managed EV charging and EV demand response to be a promising area for continued evaluation through the Innovation framework, where program design, participation, costs, system benefits, and overall cost-effectiveness can be further assessed for future DSM planning.

4.3 SOLAR-PV

Nova Scotia Power

⁹ E-3, 2025 DSM Programs Evaluation Reports, 2025 DSM Measure Assessment, March 20, 2026, page 122-123 (PDF page 906-907).

1 At PDF page 10, Brattle states:

2 *DSM funding should be reserved for resources that directly and efficiently reduce Nova*
3 *Scotia's energy and capacity supply obligations through demand-side measures or provide*
4 *measurable system value in a manner consistent with the purpose of the DSM framework.*
5 *Moreover, distributed solar PV systems already receive compensation through net*
6 *metering, so by including them in the DSM funding, they are double compensated for*
7 *ratepayer funds. In short, behind-the-meter Solar-PV raises distinct policy, rate design, cost*
8 *allocation, and equity issues that will be further discussed below and therefore should not*
9 *be embedded in the DSM portfolio.*

10
11 At PDF page 34, Brattle states:

12 *However, even if customer-owned Solar PV can be read to fit within the statutory language*
13 *as an energy-reduction measure, it does not cleanly fit within the core purpose of DSM as*
14 *a resource for reducing or managing customer demand. While customer-owned Solar PV*
15 *may reduce the customer's reliance on utility-provided energy (kWh), it does not*
16 *necessarily reduce "...the capacity that Nova Scotia Power Incorporated would otherwise*
17 *be required to supply" as articulated in the statute, when NS Power's system is most*
18 *constrained. This distinction matters because Nova Scotia's planning need is not limited to*
19 *annual energy. The record shows that NS Power is facing material winter peak and*
20 *resource adequacy challenges, and that the system value of DSM increasingly depends on*
21 *whether a resource reduces firm capacity needs during winter peak and reliability-risk*
22 *hours.*
23 *[emphasis added]*

24 25 **E1 Rebuttal Evidence**

26 E1 submits that Brattle's evidence does not support removing the Solar-PV component from the Preferred
27 Plan. Brattle concedes that customer-sited Solar PV has a textual basis within the statutory DSM definition,
28 that E1's proposed program is targeted, modest in scale, and designed to benefit Mi'kmaw communities,
29 and that the program is cost-effective under the Board-approved PAC test, with a PAC result of 1.1.

Brattle's principal objection, that standalone Solar-PV provides limited winter-coincident peak capacity, is a resource-planning and policy argument about how DSM funds should be prioritized; it does not establish that the program is statutorily ineligible or that it fails the applicable cost-effectiveness test.

The *Public Utilities Act* defines DSM with reference to reductions in energy **or** capacity. E1 has never asserted that Solar-PV is principally a capacity resource. Rather, its inclusion is based on measurable energy reductions and the associated avoided system costs. Using NS Power's avoided costs, E1's analysis demonstrates that the proposed Solar-PV offering produces positive net system benefits. If greater emphasis should be placed on winter peak capacity reductions, that distinction should be reflected in the avoided cost impacts used to assess all resources. It is not appropriate to selectively exclude a resource that satisfies the statutory definition and produces positive net benefits under the Board-approved cost-effectiveness test framework.

E1 further notes that Brattle's suggestion of "double compensated" under net metering is misplaced: as E1's application explains, participating customers receive no compensation beyond offsetting their own consumption, so the program does not layer a separate payment on top of net-metering credits. The existence of customer bill savings has never been a basis for excluding otherwise cost-effective DSM measures.

5. SOLAR NOVA SCOTIA EVIDENCE

Solar Nova Scotia provided evidence, which was filed with the Board as E-24. This section of the Rebuttal Evidence sets out new evidence of E1, responding to new concerns raised in Solar Nova Scotia's evidence with respect to BNI DSM, and savings from energy manager-supported projects, in the 2027–2031 DSM Plan.

5.1 BNI DSM

Solar Nova Scotia

At page 3 of its evidence Solar Nova Scotia states:

The evidence indicates that the future of cost-effective business DSM depends less on increasing rebate levels or free direct-install measures, and more on expanding the technical assistance, project development, funding navigation, and customer support that

1 *has already proven effective in the Custom Program. Energy Manager-supported projects*
2 *accounted for nearly all Existing Buildings Custom Program savings in 2024 and 2025,*
3 *according to EfficiencyOne's responses to Solar Nova Scotia information requests. Yet*
4 *EfficiencyOne funds only four partial Energy Manager positions through DSM, none of*
5 *which serve the small business segment, and it has chosen to direct available funds to*
6 *financial incentives rather than to this enabling support.*

8 **E1 Rebuttal Evidence**

9 E1 disagrees with the assertion that the evidence indicates future business DSM depends on expanding
10 technical assistance in the Preferred Plan. E1 and its Efficiency Preferred Partner members already offer
11 the technical and support services recommended by Solar Nova Scotia. Technical assistance included in
12 the Preferred Plan is based on expected needs of current business project pipelines and the remaining
13 targets over the plan period. While E1 does not believe expansion of Energy Manager services are needed
14 at this time, E1 has the flexibility to adjust the delivery approach during plan implementation if that
15 changes. Alternative delivery models were considered, including a Roving Energy Manager for the Small
16 Business Energy Solutions program component. E1 has a small business Energy Auditor and Energy Care
17 Representatives who assists with project identification, technical reviews, program navigation, and sharing
18 resources about supplementary funding opportunities. The Efficiency Preferred Partner network also
19 contains several highly engaged contractors who are recruiting customers to the program and supporting
20 project development in substantial ways. It was determined that program investment should remain
21 focused on customer incentives as opposed to hiring additional technical support staff to those described
22 above given near-term affordability barriers, a changing and more expensive measure-mix post-lighting
23 and rising project costs for small businesses. E1 understands that financial, project management and
24 technical barriers can exist for small businesses, all of which are addressed through the delivery model as
25 described above. Throughout Plan implementation, as customer barriers and program trends are
26 assessed, E1 has the ability to consider modifications to the delivery approach, including additional
27 technical and/or project management support.

29 **5.1.1 SAVINGS FROM ENERGY MANAGER-SUPPORTED PROJECTS**

30 **Solar Nova Scotia**

31 At page 6 of its evidence, Solar Nova Scotia States:

1 *EfficiencyOne stated in response to Solar Nova Scotia information request E1 (SNS) IR-08(e)*
2 *that 94 percent of Custom Program savings under the Existing Buildings stream were*
3 *achieved through Energy Manager-supported projects in 2024, and 90 percent in 2025.*
4 *The Custom Program is now the central source of cost-effective business savings in the*
5 *DSM portfolio, and Energy Managers support nearly all of those savings in the Existing*
6 *Buildings stream.*

7 *[...]*

8 *Despite the central role of this delivery model, the Energy Manager capacity funded*
9 *through DSM is very limited. EfficiencyOne confirmed that, as of the end of the first quarter*
10 *of 2026, only four Energy Manager positions were partially funded by DSM, of which three*
11 *are roving within the industrial sector and one is embedded with an institution (E1 (SNS)*
12 *IR-09(c)). None are dedicated to the small business segment. The delivery model*
13 *responsible for the large majority of cost-effective business savings is therefore supported*
14 *by a small, industrially focused complement of DSM-funded staff, and the customers least*
15 *able to access that support, small businesses, receive none of it.*

16
17 *Businesses that do not have access to this type of support are at a disadvantage. As*
18 *traditional low-cost prescriptive opportunities become more limited, expanding access to*
19 *Energy Manager- type support will be important to maintaining cost-effective business*
20 *savings and enabling deeper projects across a broader range of customers.*

21
22 *The same Energy Manager-type support can also enable strategic electrification,*
23 *distributed energy resources such as solar and batteries, locational DSM, demand*
24 *response, and uptake of federal tax incentives. For this reason, Solar Nova Scotia*
25 *recommends that DSM delivery place greater emphasis on customer enablement rather*
26 *than simply increasing measure incentives.*

27 28 **E1 Rebuttal Evidence**

29 E1 disagrees with Solar Nova Scotia's assertion that adding dedicated Energy Managers to support small
30 businesses will reduce the need for DSM incentives for these customers. Solar Nova Scotia has not
31 presented any data to demonstrate that small businesses are willing to accept more staff assistance in lieu
32 of financial support or that the Energy Management approach that has proven to be effective for larger,

more complex Custom projects is the best approach for small businesses. Given current economic conditions, and the need to support near-term affordability, E1 believes it is appropriate to direct most DSM funding to incentives that directly reduce customer expenses in combination with the project management and technical support included in the proposed 2027–2031 DSM Plan for small businesses.

E1 also disagrees that small business customers are at a disadvantage without Energy Manager support. E1 offers small business customers various other forms of navigation and technical support through its dedicated Energy Auditor, program staff, Energy Care Representatives, and Business Development team. E1 has a very dedicated Efficiency Preferred Partner network that provides similar supports to small business customers as well. Further, E1 can shift resources, including Energy Managers, to the areas of greatest need and could redistribute staff to better assist any customer segment or program if determined necessary to meet program objectives.

5.1.2 SMALL BUSINESS ENERGY SOLUTIONS AND BUSINESS ENERGY REBATES

5.1.2.1 REPLACE DEFAULT FREE DIRECT INSTALL WITH ADVISORY SUPPORT AND COST SHARE

Solar Nova Scotia

At pages 7 - 8, Solar Nova Scotia states:

EfficiencyOne correctly identifies two key barriers facing small businesses: an awareness gap, where participants may not understand the costs, benefits, and appropriateness of projects for their business; and a capacity gap, where participants may lack the time and capacity to manage energy efficiency projects (Appendix A, Table 40, p. 72). The proposed SBES response, an end-to-end, no-cost direct-install model, addresses those barriers by taking the project away from the customer.

That approach may be useful for some customers, but as a default model it risks driving higher program costs, limiting the number of participants that can be served with available DSM funds, and narrowing the range of projects the program can support. In a post-lighting market, a free direct-install model for higher-cost measures such as heat pumps may not be the most efficient way to address awareness and capacity barriers.

1 [...]

2 *A more efficient response would be to provide small businesses with Energy Manager-style*
3 *advisory and project-development support. This support would help customers understand*
4 *energy use, identify and prioritize opportunities, assess costs and benefits, navigate*
5 *funding, and carry projects through to implementation. Rather than funding 100 percent*
6 *of installed costs by default, EfficiencyOne could combine technical assistance with*
7 *reasonable cost-share incentives.*

8
9 *This would directly address the barriers EfficiencyOne has identified, stretch DSM dollars*
10 *across more participants and projects, build lasting customer capability, and position SBES*
11 *to support a broader set of DSM resources, including deeper efficiency, strategic*
12 *electrification, demand response, and distributed energy resources.*

13
14 At pages 9 – 10 of its evidence, Solar Nova Scotia sets out recommendations regarding Small Business
15 Energy Solutions (SBES) design, including a recommendation that the Board should direct E1 to:

- 16 • *replace full-cost direct install as the default approach with Energy Manager-style*
17 *technical assistance, project development, and funding-navigation support;*
- 18 • [...]
- 19 • *permit this support to be delivered by qualified private-sector providers where*
20 *appropriate;*

21 22 **E1 Rebuttal Evidence**

23 E1 did not propose an end-to-end direct install delivery approach for SBES in the 2027–2031 DSM
24 Preferred Plan. With respect to Solar Nova Scotia’s position that E1 should invest more in Energy
25 manager support for small businesses, E1 relies on the evidence outlined in its answers above.

26 27 **5.2 DEMAND RESPONSE**

28 **5.2.1 SMART THERMOSTATS**

29 **Solar Nova Scotia**

30 At page 10 of its evidence, Solar Nova Scotia states:

31 *EfficiencyOne plans to incentivize 121,039 smart thermostats over the Plan period,*
32 *including 68,539 provided at no cost through direct-install programming, yet confirmed in*

1 *response to Solar Nova Scotia IR-01(e) that it will not require or encourage those devices*
2 *to enroll in demand response, even where technically eligible. Tens of thousands of DSM-*
3 *funded controllable devices are therefore being deployed without securing the demand*
4 *response capability they could provide.*

5
6 *Solar Nova Scotia recommends that DSM-funded controllable devices, including smart*
7 *thermostats, electric water heaters, and heat pumps, be made demand-response capable*
8 *and integrated into DR programming wherever technically feasible, subject to appropriate*
9 *customer consent, override protections, and annual reporting on verified peak reduction*
10 *and capacity value. Enrolling devices that DSM is already paying to deploy is among the*
11 *lowest-cost sources of incremental demand response available to the portfolio.*

12 13 **E1 Rebuttal Evidence**

14 The approach E1 took for residential demand response in the 2027–2031 DSM Preferred Plan is to focus
15 on optimizing performance to achieve cost effectiveness before scaling new enrollments. The devices
16 planned to be installed during the 2027–2031 plan period as part of the energy efficiency resource are not
17 stranded assets. There is nothing inherent in this approach that prevents E1 from enrolling these smart
18 thermostats into a future residential demand response offer.

19 20 **5.2.2 LONGER-DURATION CAPACITY**

21 **Solar Nova Scotia**

22 At page 11 of its evidence, Solar Nova Scotia states:

23 *The E3 Effective Load Carrying Capability (ELCC) analysis underscores the value of longer-*
24 *duration demand response. Hybrid heating systems and back-up generators are well*
25 *suited to participate in longer-duration calls because they can sustain load reductions over*
26 *extended periods, including during the multi-hour winter peaks that increasingly drive*
27 *Nova Scotia's capacity needs.*

28
29 *[...] The DSM Plan demand response technical tables indicate that EfficiencyOne is*
30 *targeting approximately 6 MW of total back-up generator capacity in its Demand*
31 *Response Program. The scale of the available opportunity is considerably larger,*

1 *particularly as hybrid heating and back-up systems become more common in the*
2 *commercial building stock.*

3
4 At page 12 of its evidence, Solar Nova Scotia recommends that the Board do the following:

- 5 • *direct EfficiencyOne to grow back-up generator and hybrid heating demand*
6 *response capacity, with a focus on new construction, and to enable these*
7 *resources to provide longer-duration (e.g., eight-hour) calls;*
- 8 • *require EfficiencyOne to bias residential demand response acquisition toward*
9 *enabling new equipment at the point of purchase while still enrolling the*
10 *controllable devices DSM is already deploying, to reduce incremental customer-*
11 *acquisition costs; [...]*

12 13 **E1 Rebuttal Evidence**

14 At this time E1 has not been requested to provide a long-duration DR resource. Back-up generators and
15 hybrid heating are both technologies that are currently included in the demand response program. Under
16 the current residential demand response structure, requiring new enrollments scales a non-cost-effective
17 resource.

18 19 **5.3 STRATEGIC ELECTRIFICATION**

20 **5.3.1 HYBRID HEAT PUMPS**

21 **Solar Nova Scotia**

22 At page 3 of its evidence Solar Nova Scotia states:

23 *Hybrid heat pumps, managed EV charging, controllable water heating, and other flexible*
24 *electrification measures can reduce emissions, improve utilization of the existing grid,*
25 *support customer affordability, and enable further renewable and distributed energy*
26 *deployment when they are designed with controls, rate signals, external funding, and*
27 *customer support.*

28
29 At page 13 of its evidence, Solar Nova Scotia states:

30 *The same principle applies to building electrification. E3 found that heat pump adoption*
31 *can provide positive participant, ratepayer, and societal benefits in important use cases,*
32 *particularly where heat pumps displace fuel oil. E3 also found that dual-fuel mini-split*

1 *systems can provide participant, ratepayer, and societal benefits while reducing peak*
2 *impacts by using backup heating during the coldest hours.*

3
4 *This evidence is highly relevant to Nova Scotia because the Province remains heavily*
5 *exposed to heating oil, and because winter peak demand is a central system-planning*
6 *concern. Hybrid heat pumps should therefore be treated as a practical strategic*
7 *electrification measure, not as a compromise outside DSM. They can electrify most annual*
8 *heating load, reduce emissions, reduce customer exposure to fuel oil, and limit incremental*
9 *peak demand in the hours when the system is most constrained.*

11 **E1 Rebuttal Evidence**

12 E1 agrees that these noted measures may support emissions reductions, improve utilization of the existing
13 grid, and provide broader societal benefits, particularly given Nova Scotia's reliance on heating oil.
14 However, the *Public Utilities Act* requires that strategic electrification measures demonstrate both
15 greenhouse gas reductions and reductions in electricity costs. Consistent with Board direction, E1
16 evaluated these measures with the modified PAC test as the primary cost-effectiveness framework. E1
17 notes that hybrid heating measures were among the strategic electrification options evaluated during
18 multiple rounds of portfolio modelling, including scenarios with highly favourable assumptions related to
19 peak demand impacts. Even under best-case assumptions that eliminated incremental peak demand
20 impacts, the measures did not satisfy the modified PAC test. Accordingly, E1's findings suggest that
21 reducing peak impacts alone is not sufficient to overcome the challenges associated with strategic
22 electrification under the current framework. For this reason, E1 intends to continue advancing research,
23 stakeholder engagement, and collaboration on strategic electrification opportunities through the Enabling
24 Strategies activities proposed in the Plan.

26 **6. EASTWARD ENERGY EVIDENCE**

27 Eastward Energy engaged the Posterity Group to review E1's 2027–2031 DSM Plan. The Posterity Group
28 evidence was filed with the Board as E-20. This section of the Rebuttal Evidence sets out new evidence of
29 E1, responding to new concerns raised in the Posterity Group's evidence with respect to the Custom New
30 Construction baseline and incentives in the 2027–2031 DSM Plan.

6.1 CUSTOM NEW CONSTRUCTION PROGRAM BASELINE

Eastward Energy

At page 2 – 3 of its evidence, the Posterity Group states:

Industry Practice for DSM Programs

For the purposes of DSM programs, the baseline case is typically intended to represent what the energy consumption and demand would have been in the absence of the program. Accordingly, the baseline should reflect the equipment selection, fuel choices, and design decisions that a customer would reasonably have made without program incentives, which may differ from those reflected in the NECB reference building.

In the context of the NC Program, this would mean:

- Providing incentives based on the electrical energy savings of a proposed building **relative to what the electricity consumption and demand would have been for the building if it were built in the absence of the program,** rather than relative to a reference building suitable for demonstrating code compliance.*
- For proposed mixed-fuel or all-electric HVAC systems, that the baseline electric space heating consumption consider the space heating equipment fuel choices that **would have been made for the building if it were built in the absence of the program,** rather than prescriptively requiring that the baseline building have the same portion of the heating load met by electric equipment as the proposed building.*

Taken together, the current program rules and E1's responses to Information Requests suggest that E1 has not determined an appropriate baseline for the NC Program consistent with good DSM practice.

Specifically,

- As described in the Custom NC Program guidance, program electricity savings are measured against a baseline suitable for demonstrating compliance with building code rather than from a baseline reflective of what electricity consumption and demand would have been in the absence of the program.*

- *The appropriateness of this approach to developing a baseline was not tested empirically through evaluation:*
 - *Non-participants (i.e., decision-makers in the construction of new buildings who did not receive an incentive from E1) were not interviewed as part of the 2025 NC Program Evaluation.*
 - *Participant builders interviewed were not asked what space heating fuel they would have selected for their building in the absence of an incentive.*

Without this information, it is not possible to determine whether the NC Program is accurately measuring or rewarding incremental electricity savings. In fact, for participant builders that were incentivized to select efficient electric equipment who otherwise would have selected fuel-fired equipment, the NC Program would have rewarded an incremental increase in electric energy consumption and demand.

E1 Rebuttal Evidence

E1's New Construction (NC) offering is a well-established service within the Custom program component that regularly undergoes technical and market impact evaluations, including interviews with non-participating energy modellers. In its early stages (2014–2017), projects were assessed more individually with a participant specific baseline, consistent with other Custom program component offerings. E1 transitioned to a standardized approach using a baseline of locally adopted energy codes, including the National Energy Code of Canada for Buildings (NECB) and American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Standard 90.1.

Using a baseline based on code delivers material benefits, including less subjectivity, improved program consistency, and reduced customer confusion, and, most importantly, it ensures that the program applies an objective, transparent, and auditable baseline across all projects.

The use of an NECB based reference building is consistent with industry practice for commercial new construction programs. It provides a stable and verifiable basis for quantifying incremental efficiency improvements relative to a clearly defined standard.

1 In the 2020–2022 DSM Plan proceeding (M09096), E1 and Heritage Gas (now Eastward Energy) agreed to
2 jointly undertake a study, led by Dunskey Energy Consulting, with two scopes relevant to this discussion: to
3 determine how local developers choose their primary heating systems for new construction buildings,
4 both with and without incentives offered; and to complete a jurisdictional scan to evaluate how other
5 jurisdictions baseline new constructions energy models (including hybrid heating scenarios). This study
6 found that heating system selection is driven predominantly by upfront capital costs, operating costs,
7 developer comfort with the technology, and additional revenue opportunities from rentals, not incentives.
8 The Dunskey study also found that all relevant jurisdictions across North America use the modelling
9 specifications in the locally adopted energy code to define the baseline.¹⁰ E1 and Heritage Gas committed
10 to incorporating Dunskey's recommended changes to the existing New Construction service in the Custom
11 Incentives Program, subject to and following the Board's acceptance of Dunskey's study.¹¹ Furthermore, the
12 citation in the Posterity Group's evidence "Evaluation, Measurement and Verification Protocol, Version 5.0
13 – January 2025"¹² is only relevant for existing equipment, not new construction. When providing an
14 example calculation of energy savings, the Evaluation, Measurement and Verification Protocol document
15 itself states that for new construction programs, minimum code standards are usually used as measures'
16 baseline.¹³

17
18 For these reasons, comparable new construction programs across Canada similarly base savings
19 calculations to applicable energy codes. This includes programs delivered by DSM administrators such as
20 NB Power and Efficiency Manitoba, among others. Outside of DSM, other programs also rely on code-
21 based benchmarks. For example, Canada Mortgage and Housing Corporation's Mortgage Loan Insurance
22 Select program evaluates energy performance improvements relative to NECB tiers, and the Province of
23 Nova Scotia has adopted NECB 2020 Tier 1 as the minimum standard for new construction. These examples
24 reflect a consistent policy direction toward code-aligned baselines as the foundation for measuring
25 performance improvements.

¹⁰ M09096, Document 79334, Letter from E1 enclosing VRF Program Review Report, October 15, 2019, page 11.

¹¹ Ibid., Document 79335, Letter from Heritage Gas re supports position outlined by E1, October 15, 2019 and Document 79691, Board letter to E1 re Dunskey report is accepted as filed, November 18, 2019.

¹² E-20, Citation 3, page 2.

¹³ <https://www.ieso.ca/-/media/Files/IESO/Document-Library/EMV/Evaluation-Measurement-and-Verification-Protocol-V5.pdf>, page 29.

1 Given this context, the use of NECB as the reference building represents a prudent, widely accepted, and
2 practical approach to baseline development in new construction programs.

3
4 With respect to peak demand, E1's 2027–2031 DSM Plan Application proposed a Peak Demand
5 Performance Target, and outlines quarterly and annual peak demand reporting at the portfolio, program
6 and program component level. The Custom NC incentives are based on quantified energy savings aligned
7 with E1's other energy efficiency programs. Peak demand impacts are tracked and evaluated for Custom
8 NC, and are reported towards E1's Peak Demand Performance Target. This incentive structure does not
9 preclude participation in demand response initiatives. Buildings supported through the Custom NC may
10 be well-positioned to participate in existing or future demand response offerings, and E1 has, in some
11 cases, identified such opportunities through its program and research activities.

13 6.2 CUSTOM NEW CONSTRUCTION PROGRAM INCENTIVE STRUCTURE

14 Eastward Energy

15 At page 3 – 4 of its evidence, the Posterity Group states:

16 *The NC Program uses a tiered incentive structure, where incentives are calculated based*
17 *solely on the electrical energy savings, excluding lighting savings. As a result, the NC*
18 *Program does not include a mechanism to recognize peak demand reductions relative to*
19 *any baseline, whether the NECB reference building baseline, or a more appropriate DSM*
20 *baseline.*

21
22 *A primary benefit of hybrid gas/electric heating systems is their ability to reduce peak*
23 *electricity demand at the system level, potentially avoiding electricity system investments*
24 *that would put upward pressure on electricity rates and emissions. However, because the*
25 *Custom NC Program incentive structure does not account for electric demand, the*
26 *program cannot incentivize measures that would provide these potential benefits.*

28 Recommendations

29 *In summary:*

- 30 • *The Custom NC Program baseline development approach does not consider what*
31 *electricity consumption and demand would have been in the absence of the*
32 *program; and*

- *The Custom NC Program does not incentive peak demand reduction (or discourage peak demand increases).*

Taken together, this may result in the NC Program inadvertently incentivizing measures that increase peak electricity demand and ultimately increase system costs and emissions over time.

Based on the above, Posterity Group recommends that E1:

- ***Undertake additional evaluation activities to establish an appropriate DSM measure baseline for the NC program. This should include assessing both participant and non-participant decision making to better understand the design choices that would have occurred in the absence of Program incentives.***
 - *Recognizing current timing constraints, E1 could, as an interim measure, assess Custom NC Program impacts for both all-electric and mixed-fuel HVAC systems relative to a common all-electric baseline. While imperfect, this approach would provide a more equitable comparison that would more accurately quantify the electricity demand reduction benefits of proposed mixed-fuel HVAC systems relative to equivalent proposed all-electric systems.*
- ***Revise the incentive structure of the Custom NC Program to recognize the system-level impacts associated with building design decisions. This should include explicitly accounting for the value of configurations like hybrid heating systems that reduce or do not increase peak electricity demand.***

E1 Rebuttal Evidence

E1 disagrees that the Custom New Construction Program's incentive structure fails to recognize system-level benefits. As discussed above, the Program uses a consistent and objective baseline methodology grounded in the NECB Performance Path, which evaluates whole-building energy performance and does not preclude participation by hybrid heating systems. The Program's incentive structure is intentionally focused on energy performance relative to code, reflecting both the NECB framework and the Program's objective of encouraging buildings to exceed current code requirements. By incentivizing progressively higher levels of energy performance, the Program supports the early adoption of future, more stringent

1 energy code requirements. To the extent that improved building energy performance reduces coincident
2 electricity demand, those benefits are inherently captured through the Program’s emphasis on whole-
3 building energy efficiency.

4
5 Eastward Energy claims that Custom NC “cannot incentivize measures that would provide these potential
6 benefits.”¹⁴ E1 can and does indirectly incent measures that provide peak demand reduction through
7 Custom NC using the energy-based incentive structure. Specifically, for the hybrid gas/electric heating
8 example Eastward Energy uses for in their argument, E1 notes that such a configuration is eligible in the
9 program now.

¹⁴ E-20, page 4.



IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended

-and-

IN THE MATTER OF An Application by EfficiencyOne for Approval of the 2027–2031 Demand Side Management (DSM) Purchase Agreement between EfficiencyOne and Nova Scotia Power Inc., the establishment of a final agreement between the parties, and approval of a 2027–2031 DSM Resource Plan

Rebuttal Testimony of Apex Analytics

M12780

Filed with the Nova Scotia Energy Board

July 24, 2026

1 **Q. What is the purpose of the testimony of Apex Analytics?**

2
3 A. Apex provides this rebuttal testimony to address several key points raised by intervenors
4 as part of EfficiencyOne's (E1) 2027-2031 DSM Plan filing, in particular, those related to
5 savings goals, unit costs, and incentive setting. Apex submits this rebuttal testimony to
6 respond to specific themes raised in the intervenor evidence of Theodore M. Love on behalf
7 of the Consumer Advocate, Alice Napoleon on behalf of Counsel to the Nova Scotia Energy
8 Board, and the Brattle Group on behalf of Nova Scotia Power.

9
10 **Q. What are the key points that Apex is addressing in this testimony?**

11
12 A. This testimony addresses claims that E1's proposed 2027–2031 DSM Plan is not
13 sufficiently ambitious relative to prior Integrated Resource Plan (IRP) scenarios, that overall
14 unit costs are too high, that incentive levels require additional study or reduction, and that
15 the portfolio places too much emphasis on traditional energy efficiency rather than demand
16 response. As explained below, it is Apex's opinion that the methodologies and comparison
17 jurisdictions used to assist E1 in establishing its budget and savings goals for 2027-2031 are
18 appropriate for Nova Scotia.

19
20 **Q. What further explanatory information is Apex providing in this testimony?**

21
22 A. The following sections explain why Apex's benchmarking approach relied on targeted
23 comparator jurisdictions rather than broad fleet-wide averages. In Apex's professional
24 opinion, a meaningful comparison must account for climate, building stock, program
25 maturity, portfolio composition, evaluation results, and other factors that materially affect
26 achievable savings and unit costs. Apex further demonstrates that rising acquisition costs
27 are consistent with mature efficiency portfolios, in which low-cost measures have been
28 exhausted and the remaining savings opportunities are more complex and more expensive
29 to acquire. Critically, rising costs do not, in and of themselves, reflect administrative
30 inefficiencies.

31
32 Apex further details the work performed to support E1's incentive-setting process, including
33 its review of prior research, administrator interviews, industry literature, and incremental
34 cost data. Apex also describes the structured working sessions conducted with E1 program
35 managers as part of Apex's review of the incentive-setting process and explains why the
36 resulting approach is consistent with best practices. Apex concludes by addressing
37 arguments that the portfolio should shift more heavily toward demand response, explaining
38 that E1's plan should not be viewed as a choice between energy efficiency and demand
39 response, but rather as a deliberate effort to right-size both strategies while preserving the
40 cost-effective and long-lived benefits of energy efficiency.

Q. What do Nova Scotia Power and the Consumer Advocate question in Apex's unit cost comparison methodology and why is their alternative unsuitable for E1's purposes?

A. Nova Scotia Power questions whether the peer group used by Apex is sufficient, and instead provides average data from the 2026 American Council for an Energy-Efficient Economy (ACEEE) Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth report, which provided data from 42 large utilities in the U.S.¹ The Consumer Advocate also advocates for benchmarking against the utilities in this report, treating the fleet-wide average of roughly CAD\$0.35/kWh net at meter as the relevant comparator. Neither party, however, states why this group of utilities would be a better comparison group beyond being a larger pool, nor do they provide any characteristics relating these utilities to E1.

A larger sample does not, on its own, produce a more reliable benchmark. A single fleet-wide average that blends utilities in different climates, with different measure mixes, different eligibility to claim Codes and Standards savings, and different regulatory mandates is not a meaningful benchmark; it obscures precisely the differences that drive the cost of savings.

Q. Why is Apex's benchmarking more meaningful than a broad comparison with large U.S. utilities?

In performing a benchmarking analysis, peers must be similar enough to make comparisons meaningful. Broadly comparing the cost of savings in Nova Scotia to an assortment of large U.S. utilities ignores the very real differences in service areas and programs that affect measure mix, load shapes, and achievable potential and the cost to acquire savings in a given jurisdiction. Notably, the intervenors themselves concede the principal drivers of E1's rising costs - the exhaustion of low-cost lighting, the downward revision to evaluated heat-pump savings, the end of the Greener Homes grant, and inflationary pressures - so the dispute is not whether these factors exist, but whether a raw fleet average can fairly capture them.

Q. What does Apex believe is the appropriate benchmarking methodology and what factors affect unit costs?

A. In recommending savings goals and reviewing unit costs, Apex sought to benchmark against appropriate comparator jurisdictions, understanding that criteria such as climate, building stock, and program delivery and evaluation results significantly change the savings potential and the cost of those savings. The smaller sample size was by design – Apex did not just average costs across North America, but recognized that benchmarking only

¹ Mike Specian and Alex Aquino, Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth, ACEEE, February 4, 2026. [Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth | ACEEE](#)

1 provides value if the characteristics of the comparison jurisdictions can be replicated in the
2 target jurisdiction. As Apex has previously described, there are many factors affecting costs
3 to achieve savings, including without limitation:
4

- 5 • **Program maturity and historical investment levels.** Jurisdictions with long-
6 standing programs often face higher marginal acquisition costs as lower-cost
7 opportunities are exhausted, whereas newer portfolios may still have lower-cost
8 savings available.
- 9 • **Climate and end-use load shapes.** Regional differences in heating and cooling
10 demand significantly affect achievable savings, particularly for HVAC-focused
11 portfolios.
- 12 • **Energy prices and avoided costs.** Higher avoided costs can justify greater spending
13 per kWh saved, while lower-price jurisdictions may appear less expensive on a unit
14 basis even with similar program impacts.
- 15 • **Regulatory requirements and policy mandates.** Explicit requirements related to
16 equity, electrification, or market transformation (which can decrease opportunities
17 from low-cost savings programs like lighting or reduce claimable savings through
18 lower net to gross ratios) can increase unit costs.
- 19 • **Eligibility to claim Codes and Standards (C&S) savings.** Jurisdictions permitted to
20 count C&S savings will typically report lower average unit costs given the scale and
21 low marginal cost of those savings.
- 22 • **Portfolio composition across customer classes.** Portfolios with higher shares of
23 low-income, residential retrofit, or deep EE measures will generally show higher
24 \$/kWh values than portfolios dominated by commercial lighting, industrial process
25 improvements, or residential behavior programs.

26
27 **Q. Why is using the Faster and Cheaper report as a benchmark for unit costs without**
28 **additional analysis inappropriate in this instance?**
29

30 A. As an initial factor, looking at climate zones for the utilities in the Faster and Cheaper
31 report shows that approximately two thirds of the 42 utilities with budget and savings data in
32 the report are predominantly in American Society of Heating, Refrigerating, and Air-
33 Conditioning Engineers (ASHRAE) climate zones 1-4, which are characterized by warmer
34 temperatures than Nova Scotia. Warmer temperatures typically yield higher quantities of
35 inexpensive cooling savings that are not available in Nova Scotia. This immediately calls into
36 question the comparison to warmer southern and western utilities. It also undercuts the
37 Consumer Advocate's reliance on a converted "net at meter" figure of \$0.72/kWh: the more
38 than double the fleet average characterization is a result of comparing E1, a cold-climate

1 winter-peaking jurisdiction, against a grouping dominated by warm-climate utilities. On the
2 intervenors' own data, E1's cost falls within the observed range of the 42 utilities, reinforcing
3 that the comparison is not appropriate for the climate and programmatic reasons described
4 above.

5
6 **Q. What happens when you dig a little deeper into the utility programs listed in the**
7 **Faster and Cheaper report?**

8
9 A. Nova Scotia Power noted that programmatic changes such as the moving away from low-
10 cost, high-volume offerings like LEDs could also be affecting other utilities, but did not state
11 that all utilities have transitioned from low-cost savings, nor did it remove any states from
12 the comparison group. Indeed, Georgia Power Co., which has the lowest cost of *lifetime*
13 savings in Table C-1 of the Faster and Cheaper report², reported that in Q4 2024, 42% of
14 residential savings came from behavioral programs, and another 28% came from specialty
15 lighting.³ In 2026, the behavior program accounts for 50% of planned residential kWh
16 savings.⁴

17
18 Salt River Project (SRP), which had the lowest cost of *annual* savings, provides a clear
19 example of unique program elements that are not replicable in Nova Scotia. Located in
20 Arizona, SRP's biggest residential program is dominated by inexpensive air conditioning
21 savings in their Efficient Home Program. SRP also implements a codes and standards
22 program where they claim extremely inexpensive savings that lowers the average costs
23 across the portfolio. The Fiscal Year (FY) 2025 report shows a budget of USD\$70,042 for the
24 residential SRP Building Energy Code Initiative and savings of 12,233 MWh, which is equal to
25 USD\$0.006/kWh saved, which is fractions of a penny per kWh saved.⁵ For the commercial
26 building codes program, SRP claimed over 160,000 kWh savings with no associated cost (the
27 third largest C&I program). This brings the average unit cost down. SRP also claims savings
28 from shade trees, offers a behavioral program, and claims savings from a pre-paid budget
29 billing program. Given these factors, comparison of E1 with SRP is not a meaningful exercise
30 and does not support unit costs that would allow for delivery of successful programs in Nova
31 Scotia.

32
33 **Q. What happens to the unit cost comparison if you look at a wider range of utilities,**
34 **using the ACEEE 2025 State Scorecard?**

35
36 A. The Faster and Cheaper report only looks at large utilities, whereas the ACEEE 2025 State
37 Energy Efficiency Scorecard (which relies on 2023 data) takes a broader view, and includes

² Ibid., page 86.

³ <https://psc.ga.gov/search/facts-document/?documentId=221493>

⁴ <https://psc.ga.gov/search/facts-document/?documentId=226612>

⁵ <https://www.srpnet.com/assets/srpnet/pdf/about/2025-Customer-Programs-Report.pdf>

data from smaller utilities as well. When looking at states that are in the same climate zone as Nova Scotia (predominantly in ASHRAE 6A), E1's first-year EE unit cost of \$0.66/kWh are within the range of these states:⁶

State	Cost per kWh (converted to CAD) ⁷
Minnesota	\$0.27
Wisconsin	\$0.28
Maine	\$0.69
New Hampshire	\$0.82
Vermont	\$0.92

Other northern climate zones show a range of unit costs from CAD\$0.25-\$2.76, with an average of \$0.93 (ASHRAE climate zone 5A). This shows that even with just one criterion layered on top of the overall data, the cost to achieve savings is significantly different than the average costs of large utilities provided by the intervenors and is more closely aligned with the unit costs proposed by E1. When the comparison is limited to jurisdictions that resemble Nova Scotia in climate, E1's first-year unit cost falls well within the observed range; the appearance of an outlier arises only from the intervenors' use of a blended national average.

Q. What happens to the unit cost comparison if you look at a smaller set of comparator jurisdictions, using their recent regulatory filings?

A. Apex reviewed regulatory filings of potential comparator jurisdictions and analyzed additional variables beyond general climate zones such as local climate (more granular than ASHRAE zones), building stock characteristics, energy pricing, socioeconomic conditions, and similarities in program design and delivery. Within each of these categories, multiple variables were also analyzed. Within this analysis, E1 still ranked consistently well within the range of unit costs. The table below is taken from Apex's *Review of EfficiencyOne First-Year Costs and Unit Cost Reasonableness* memo provided to E1 and submitted in response to information request IG IR-10.

⁶ US\$ per kWh were derived from dividing state budgets from Table 10 by the net incremental energy savings in Table 7 in the ACEEE 2025 State Scorecard by available at, <https://www.aceee.org/research-report/u2502>

⁷ Based off average exchange rate of Jan-Jun 2026 from Bank of Canada, available at <https://www.bankofcanada.ca/rates/exchange/monthly-exchange-rates/>

First-Year Unit Costs Ranked from Most to Least Expensive on a Portfolio Basis

Jurisdiction	Portfolio
	CAD
Newfoundland and Labrador	\$1.38
New Brunswick (w/o Industrial Program, Business Rebate)*	\$1.12
New Hampshire	\$0.96
Vermont	\$0.89
Prince Edward Island	\$0.86
EfficiencyOne	\$0.66
New Brunswick**	\$0.35
Manitoba***	\$0.25

* This estimated cost for New Brunswick removes cost and savings associated with the Industrial Program, as well as costs associated with programs with no associated savings.

** New Brunswick's Initiatives Update had a \$0.06/kWh cost for its Industrial Program, which appears to be an outlier compared to other jurisdictions. This extremely low cost for Industrial savings substantially brings down the overall portfolio cost.

*** Manitoba costs were taken directly from their 24-25 Annual Report Supplement. However, Apex does not consider Manitoba to be a reliable comparator for E1's portfolio given significant differences in portfolio composition, savings attribution methods, and measure mix. Manitoba is included in this analysis for completeness and transparency, but should be given limited weight in assessing E1's cost reasonableness.

Q. Does Apex believe that the 2027-2031 DSM Plan savings goals are reasonable?

A. In our opinion, E1's 2027-2031 goals seem reasonable and appropriate given the mature nature of the programs and the emphasis in this Plan on near-term affordability. E1's proposed goals are lower than what was in the IRP Base Scenario but are still consistent and within range of what Apex has observed from jurisdictions deemed to be similar to Nova Scotia across a number of variables. The states and provinces that Apex determined were most similar to Nova Scotia had a range of annual savings goals ranging from 0.32% to 1.74%. Many of the states/provinces at the higher end of that range, such as Michigan, New York, and Ontario were the least similar to Nova Scotia within the smaller comparator group. When the analysis is narrowed to the jurisdictions most similar to Nova Scotia, the annual savings goals cluster more tightly around 0.8-1%, and accordingly, Apex concluded that this range would be reasonable for E1, particularly as it is consistent with E1's 2023-2025 DSM Plan at 1% and the 2026 DSM extension at 0.87%.

Given E1's concern with short-term affordability, and the emphasis on affordability as a primary consideration throughout the 2027-2031 DSM Plan, Apex finds it is reasonable that E1 selected a goal towards the lower end of the recommended range. Choosing a target towards the lower end of the range is supported by the fact that E1 sought to maintain stable budget levels while simultaneously removing low-cost, high-volume measures such as behavioral programs from the portfolio.

1 It should also be noted that the latest IRP Evergreen was completed in 2022, and market
2 conditions and costs have shifted since that time. This version of the IRP is now 4+ years old
3 and it is unknown if an updated IRP would recommend similar levels of energy efficiency. As
4 a point of reference, the Consumer Price Index for Nova Scotia for all items excluding food
5 and energy has gone up ~16% from January 2022 to May 2026,⁸ showing that what might
6 have been reasonable or economic when the last IRP was completed may not be today.

7
8 **Q. Does Apex believe that rising program and implementation costs are necessarily a**
9 **reflection of inefficient program administration?**

10
11 A. No, Apex does not believe that E1's rising unit costs are reflective of inefficient program
12 administration. Similar to Nova Scotia, rising unit costs are common across comparison
13 states; this is indicative of mature programs, not a sign of inefficiencies. Rising unit costs
14 are expected for more developed programs due to removal of low-cost savings programs and
15 successful completion of easier, cheaper savings opportunities.

16
17 **Q. Has Apex observed rising costs in other mature jurisdictions?**

18
19 A. Yes. As shown in E1's response to IG IR-10, Attachment 2, Massachusetts, which has long
20 standing programs with robust budgets, removed its behavioral and lighting programs since
21 2019 and the cost to acquire savings has steadily and consistently increased over time.
22 Program planning and administration costs rose from 3.8% to 5.4% of total portfolio budget
23 from the 2019-2022 Plan to the 2025-2027 Plan, with Sales, Technical Assistance & Training
24 going from 13.5% to 22.4%, and Marketing increasing from 2.6% to 4.4%.

25
26 Another energy efficiency program administrator in the Northeast, Efficiency Maine, with
27 mature programs has seen public information costs rise nearly 40% from the FY 2021 Plan
28 to the FY 2026 Plan, with Innovation budgets increasing 138% and administration costs going
29 up over 61%.⁹ Again, this is not necessarily indicative of inefficient administration of energy
30 efficiency programs, but rather a reflection of market realities that easier/lower cost
31 opportunities have been captured, and more effort and resources need to be expended to
32 capture additional savings.

33

⁸ Statistics Canada, available at

<https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000401&pickMembers%5B0%5D=1.7&cubeTimeFrame.startMonth=01&cubeTimeFrame.startYear=2022&cubeTimeFrame.endMonth=05&cubeTimeFrame.endYear=2026&referencePeriods=20220101%2C20260501>

⁹ https://www.efficiencymaine.com/docs/FY20-Annual-Report_final_11.18.2020.pdf, Appendix C;
<https://www.efficiencymaine.com/docs/FY2025-Annual-Report.pdf>, Appendix D

1 The Faster and Cheaper report uses data from 2024, which is not necessarily indicative of
2 savings and costs on a go-forward basis. In addition to the impacts of mature programs,
3 program priorities (including equity and low-income service) and global economics play a
4 role in increased costs for the future.

5
6 **Q. What other market and program forces help explain E1's rising unit costs?**
7

8 A. Measurement & Verification updates and net savings adjustments have a significant
9 impact on claimable savings. As programs mature, evaluations often reduce net-to-gross
10 ratios and reported savings as equipment markets mature and transform. While this is widely
11 regarded as a sign of program maturity rather than declining performance, the impact is
12 lower claimable savings.

13 Programs are also subject to market transformation effects. Codes, standards, and
14 consumer preferences increasingly default to efficient measures and products over time,
15 with the result being that remaining opportunities are often more complex and expensive. As
16 energy efficiency programs mature over time, the allocation of the portfolio budget has to
17 necessarily change as well, as early adopters and other easily captured savings have been
18 claimed. Many programs see increased implementation and delivery costs related to more
19 complex projects and the increased education and marketing needed to reach additional
20 customers. The Consumer Advocate points out that customer incentives (which include
21 some components of delivery costs) now account for roughly 71% of total Plan costs, up
22 from 66% in the 2026 Plan. The fact that E1 has maintained a high and growing share of
23 spending directed to customer incentives and program delivery indicates effective cost
24 management within a maturing portfolio.

25
26 **Q. Have incentives been set in accordance with industry best practices?**
27

28 A. Separate from any benchmarking exercise, the Consumer Advocate recommends
29 examining the absolute level of costs from incentives. As a way to control costs, the
30 Consumer Advocate seeks additional evidence on incentive setting. As a general principle,
31 incentives should be high enough to drive participation but no higher than necessary, and
32 that incentive levels should be periodically reviewed. As part of the Apex review process,
33 Apex assessed absolute levels of incentives and also looked at relative percentages of
34 incentives, i.e., what percent of incremental cost incentives typically cover in other
35 jurisdictions. While this was not necessarily a project that conducted primary customer
36 research or price sensitivity analysis, it did show that E1 was in line with other energy
37 efficiency administrators and was following industry standard practice in the setting of
38 incentives. This effort was designed to ensure that incentive levels are aligned with market
39 conditions, customer needs, and industry best practices.

Apex reviewed E1's incentive-setting process and compared it to best practices that were informed by prior research, including the CLEARResult incentive study. Apex conducted interviews with energy efficiency program administrators and undertook a review of industry literature. Apex translated these findings into recommendations for potential improvements to E1's structured Incentive Setting Process (ISP), including a practical decision framework and accompanying process flow diagram. The Apex team also developed a matrix identifying appropriate relative and absolute incentive levels across program types, customer sectors, and replacement scenarios, and updated incremental cost assumptions for more than 300 commonly installed measures using data from over 60 sources. Finally, Apex worked closely with E1 program managers through a series of workshops and working sessions to apply the framework and update incentive levels for future program years. Given this comprehensive process, it is Apex's professional opinion that E1's incentive-setting procedures are consistent with industry best practices. Apex's recommendations were consistent with the existing ISP, including the use of thresholds to help set incentives; the Apex team updated the thresholds themselves and the underlying incremental costs.

As part of the incentive setting engagement, Apex provided E1 with best practices and common ranges of incremental costs that incentives typically cover for energy efficiency measures. As an example, Table 3 in the incentive setting best practices memo (shown below and included in IG IR-11 Attachment 1) provides percentage ranges of incremental costs that incentives should cover, incentive upper limits, and where appropriate, \$/kWh ranges for specific program types. These ranges were based off extensive jurisdictional research and interviews with energy efficiency program administrators. As part of this exercise, Apex also provided E1 with a detailed spreadsheet that contained incremental costs for over 300 measures. The Apex team utilized over 60 different sources to come up with the updated incremental costs including Technical Reference Manuals from other energy efficiency providers, pricing data from other utilities, and real time pricing from retailers such as Home Depot.

Incentive Setting Matrix¹⁰

Sector	Delivery	Replacement Type	Suggested Basis	Range	Suggested Upper Limit
Res	Rebate	Retrofit	Project Cost	30-75%	100%
Res	Rebate	ROB	Incremental Cost	30-75%	100%
Res	DI	Retrofit	Project Cost	75-100%	100%
Res	DI	ROB	Incremental Cost	75-100%	100%
Large BNI	Rebate	Retrofit	Project Cost	30-80%	90-100%
Large BNI	Rebate	ROB	Incremental Cost	15-100%	90-100%
Small BNI	Rebate	Retrofit	Project Cost	30-75%	90-100%

¹⁰ Sourced from Apex Analytics' Incentive Setting Best Practices memo

Sector	Delivery	Replacement Type	Suggested Basis	Range	Suggested Upper Limit
Small BNI	Rebate	ROB	Incremental Cost	30-75%	90-100%
Small BNI	DI	Retrofit	Project Cost	30-100%	90-100%
Large BNI	Custom	N/A	Project Cost	\$.08-\$0.25/kWh	70%
Small BNI	Custom	N/A	Project Cost	\$0.20-\$0.70/kWh	100%
AMH	Rebate	N/A	Project Cost	30-80%	100%

1 Res = Residential
 2 BNI = Business, Non-Profit, and Institutional
 3 DI = Direct Install
 4 AMH = Affordable Multifamily Housing
 5 ROB = Replace on Burnout
 6

7 As part of the incentive update process, the Apex team also walked through how to apply the
 8 best practices with a number of E1 program managers. This was done to ensure that updated
 9 incentive levels for the upcoming plan would follow North American best practices and
 10 would use the new incremental cost data.
 11

12 **Q. Is additional third-party incentive review needed?**

13
 14 A. An external review can provide additional data points but is also costly. It is also not a
 15 given that a third-party review of incentive costs would lead to lowering of incentives. Apex
 16 observed that E1 had processes in place to review and document incentive levels. The E1
 17 ISP is formally established, and includes procedures such as internal roles and
 18 responsibilities, definitions of incentives, and requirements for when the ISP must be
 19 followed. E1 documents programs and markets impacted by the measure(s). It examines
 20 information from other jurisdictions, including technical assumptions such as energy
 21 savings values, demand savings values, measure life, incentive level. It takes into account
 22 insights gained from performance of due diligence by speaking with key stakeholders to
 23 better understand incremental cost, potential incentive levels, and market trends. E1 has
 24 strong relationships with its trade allies, who work directly with customers, to validate the
 25 need for incentives and the potential impacts of various incentive levels. E1 also has strong
 26 knowledge of program delivery models and its customer base. Finally, E1 considers energy
 27 savings assumptions in setting incentives. Given these mechanisms and the work that Apex
 28 has already completed, it is Apex's opinion that an additional third-party study is unlikely to
 29 yield material insights beyond those already developed and would not justify the associated
 30 cost.
 31

32 **Q. Is the portfolio appropriately weighted towards energy efficiency?**

33
 34 A. From Apex's review of the 2027-2031 DSM Plan, it is clear that E1 continues to see strong
 35 value in energy efficiency to benefit the climate, reduce energy costs, and provide customers

1 with more comfortable homes and businesses. Intervenors have discussed the merits of
2 demand response and suggested that additional emphasis be placed on demand response
3 over energy efficiency. This does not have to be an either/or exercise; rather, it is possible to
4 right-size both strategies given where they are on the program maturity spectrum, taking into
5 account required program cost-effectiveness considerations. Energy efficiency is cost-
6 effective (as demonstrated by the benefit-cost ratios in the Plan, which exceed those of the
7 proposed demand response programs) and has durable lifetime benefits, including
8 permanent peak load reductions. In Apex's professional opinion, E1 should continue to
9 prioritize energy efficiency balanced with affordability, while also establishing and growing
10 beneficial, cost-effective demand response programs.