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June 23, 2026

Crystal Henwood
Clerk of the Board
Nova Scotia Energy Board
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3S3

Re: M12780 EfficiencyOne 2027-2031 Demand Side Management Plan – Third-Party Expert Evidence

Dear Ms. Henwood:

On March 31, 2026, EfficiencyOne (E1) filed an application with the Nova Scotia Energy Board (NSEB, Board) for approval of a Demand Side Management (DSM) Purchase Agreement between E1 and Nova Scotia Power Inc. (NS Power, Company) and its DSM Resource Plan for the five-year term, 2027-2031 (Preferred Plan).

NS Power engaged The Brattle Group (Brattle) to review E1's Preferred Plan and assess its proposed 2027-2031 DSM Plan. In accordance with the Board's established timeline, the Company submits Brattle's Evidence as Attachment 1.

Respectfully,

Jennifer Power
Director, Regulatory

An Assessment of EfficiencyOne's 2027–2031 DSM Plan

PREPARED BY

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JUNE 22, 2026

Brattle

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- Authors would like to acknowledge the excellent research assistance provided by Brattle Energy Research Associate Adam Bigelow and Brattle Energy Analyst Andrew Bottcher.

TABLE OF CONTENTS

I. Introduction

Demand-side management (DSM) is an important electricity system resource. Properly designed and delivered, DSM can reduce the amount of electricity and capacity that Nova Scotia must supply, defer or avoid higher-cost system investments, reduce customer bills, and support reliability during periods of system stress. DSM is no longer limited to traditional energy efficiency measures; it can include energy efficiency (EE), conservation, demand response (DR), peak reduction, strategic electrification (SE), and other activities that reduce the energy or capacity Nova Scotia Power (NS Power) would otherwise be required to provide. In a system facing decarbonization requirements, electrification pressures, reliability needs, and affordability constraints, DSM should transition to an effective resource planning tool, from a portfolio of customer rebate programs.

EfficiencyOne (E1) occupies a unique role in Nova Scotia's electricity sector. In many jurisdictions, the electric utility plans, administers, and integrates DSM programming directly with its generation, transmission, distribution, rate design, and system planning functions. Nova Scotia is different. E1 is the independent franchise holder responsible for supplying DSM to Nova Scotia Power under a Nova Scotia Energy Board (Board)-approved purchase agreement. This model gives E1 a specialized delivery role and has supported the development of a recognizable and experienced DSM administrator in the Province. At the same time, it also requires particular care to ensure that DSM planning remains fully aligned with Nova Scotia's evolving system needs, customer affordability, and least-cost resource planning, which will now be overseen by the newly formed Independent Electricity System Operator (IESO) Nova Scotia.

The importance of DSM is therefore not in dispute. The relevant question is whether E1's proposed 2027–2031 DSM Plan reflects the right mix of DSM resources, the right level of spending, and the right allocation of ratepayer funding to various alternative DSM resources in light of current provincial circumstances. Similar to many other jurisdictions in North America, Nova Scotia customers have also been experiencing increasing rate pressures, and the electricity system is entering a period in which peak demand, flexibility, and strategic electrification will become increasingly important. In that context, DSM funding should be directed to the resources that provide the greatest value to customers and the power system, while avoiding or deferring expenditures that may be desirable in a broader policy sense but do not properly belong in a DSM ratepayer-funded portfolio.

Our evidence addresses E1's proposed Plan from that perspective. We recognize the value of DSM and the role E1 has played in delivering DSM programs in Nova Scotia. However, we also conclude that the proposed Plan raises important concerns regarding affordability, resource balance, and the appropriate scope of DSM funding. In particular, the Plan should be assessed against whether it adequately responds to recent rate pressures, whether it moves quickly enough from rising-cost traditional energy efficiency toward demand response and strategic electrification, and whether customer-sited solar photovoltaics (PV) should be funded through the DSM framework at all.

II. High Level Assessment of E1's Preferred Plan

At a high level, E1's proposed 2027–2031 DSM Plan is framed around affordability, near-term ratepayer protection, and continuity of DSM programming. That framing is appropriate. Nova Scotia customers have experienced significant electricity rate pressures, and Nova Scotia Power has itself acknowledged the need to balance affordability concerns with investments required for a reliable and future-ready electricity system.[1] E1's Plan responds to that context by holding annual DSM investment at the approved 2026 level of $63.75 million, for a total five-year investment of $318.75 million, with no annual inflationary increase.[2] E1 also presents the Plan as cost-effective at the portfolio level, with a Program Administrator Cost (PAC) ratio of 2.4, estimated lifetime benefits of $682.5 million, and a payback period by mid-2032. These are important considerations, and they support the continued value of DSM as a resource.

However, the question for this proceeding is not whether DSM has value. It is whether the proposed resource mix is the most affordable and prudent mix of DSM investments for Nova Scotia ratepayers during the 2027–2031 period. In our view, E1's stated affordability objective should lead to stronger scrutiny of where DSM dollars are being spent; how quickly the portfolio is adapting to changing system needs; and whether ratepayer-funded DSM should include activities that are better addressed through other policy or funding mechanisms. A plan can be

1 Nova Scotia Power, "Changes to Power Rates," accessed June 17, 2026, https://www.nspower.ca/about-us/regulations/changes-to-power-rates.

2 All dollar values are expressed in CAD. Any value converted from USD was done so using the Bank of Canada's 2025 USD to CAD exchange rate of 1.3978.

"affordability framed" in total spending terms, while still failing to allocate funding to the most valuable or strategically important DSM resources.

The proposed Plan remains heavily weighted toward traditional energy efficiency. EE continues to provide important customer and system benefits, but the Plan itself shows that the market is changing and that traditional EE is becoming more expensive and more difficult to scale. E1 reports a first-year EE unit cost of $0.66/kWh, while explaining that energy savings are decreasing relative to the 2023–2026 Plan due to the transition away from lower-cost lighting, declining Home Energy Assessment savings following the closure of the Canada Greener Homes Grant, and the removal of Residential Behavior programs. The average first-year EE unit cost of the previous plan was $0.41/kWh, increasing from $0.33/kWh in 2023 to $0.49/kWh by 2026.[3] The Preferred Plan allocates approximately $286.8 million (90% of total investment) to the EE portfolio, including enabling strategies, compared with $29.1 million (9% of total investment) for DR and $2.8 million for Solar-PV (1% of total investment). The previous plan similarly allocated 94% of the total investment to EE and 6% of total investment to DR (Solar-PV was not present in the prior plan).[4] This composition largely mimics the allocations in the 2023–2026 plan and indicates that the Plan largely maintains the existing DSM delivery model rather than materially rebalancing toward the resources that are likely to become more important in a winter-peaking, electrifying, and increasingly capacity-constrained system. Having had significant success with the delivery of the EE programs, E1 is in a good position to use this experience and know-how to propose a more sophisticated portfolio of DSM measures that can better respond to the changing system requirements.

Demand Response should play a larger and more disciplined role in the 2027–2031 DSM portfolio. DR provides system value because it can reduce load during the hours when the system is most stressed and when avoided capacity is most valuable. DR involves voluntary short-term reductions in electricity consumption triggered by grid reliability conditions or high prices. This response avoids the need to dispatch less efficient and more expensive generation during high-demand periods, as well as reduces the need to build peaking capacity when it can be aggregated into a sizable, dispatchable portfolio. These principles are directly relevant to Nova Scotia, where peak demand, winter reliability, and flexible load management are becoming increasingly important. Yet under E1's Plan, DR investment remains relatively modest: $29.1 million over five

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3 EfficiencyOne, *Attachment 1 to Response to Industrial Group Information Request No. 21*, filed in *M12780*, May 28, 2026.

4 EfficiencyOne, *EfficiencyOne 2023–2025 DSM Resource Plan Filing*, , March 11, 2022, Appendix A, p. 40.

years, producing 29.3 MW of available capacity, representing less than one percent for a system with 2,460 MW peak, with a levelized unit cost of $240.1/kW-year and a PAC result of 1.7.[5]

The Plan's DR proposal also demonstrates why greater accountability is required. E1's own analysis shows that the Residential Demand Response component has a PAC result of only 0.7 over the Plan period, while business, non-profit, and institutional ("BNI") Demand Response has a PAC result of 2.4.[6] The Plan responds by limiting new residential enrollment and focusing BNI growth, but the evidence should go further. If DR is to receive increased investment, it should be subject to clearer performance obligations, more transparent cost-per-kW metrics and stronger measurement and verification. DR should not be treated merely as another customer program; it should be planned and measured as a dispatchable system resource.

The same principle applies to Strategic Electrification. 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.[7] 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.

Another important consideration is that the modified PAC test creates a structural barrier for strategic electrification because the only benefit it captures is increased utility revenue from higher electricity sales, while it excludes many of the broader benefits that motivate electrification, including other energy cost savings and emissions benefits. This narrow framework makes it unlikely that E1 can develop a robust SE portfolio that passes the test. Comparative evidence from other jurisdictions suggests that broader cost-effectiveness frameworks, such as the Total Resource Cost (TRC) test, Societal Cost Test (SCT), or jurisdiction-specific tests, are more commonly used to comprehensively evaluate the benefits of strategic electrification; however, given Nova Scotia's statutory constraints, the practical recommendation

[5] EfficiencyOne, *EfficiencyOne 2027–2031 DSM Resource Plan Application*, , March 31, 2026, Table 9, p. 58.

[6] Ibid.

[7] Id., p. 35.

is to improve program design and data while recognizing that there may not be a robust path for SE in Nova Scotia under the current modified PAC framework.

Solar-PV should not be included in the DSM portfolio. E1 proposes a small Solar-PV component of $2.8 million, representing approximately 0.9 percent of total DSM investment, with 200 installations, 2 MW of installed capacity, 1.7 GWh of first-year generation, and a PAC result of 1.1.[8] The targeted support for Mi'kmaw communities is an important policy objective, and there may be good reasons for government, federal, Indigenous, or clean energy funding to support those investments. However, the fact that a program has social, environmental, or equity value does not mean it should be funded through DSM funding. DSM funding should be reserved for resources that directly and efficiently reduce Nova Scotia's energy and capacity supply obligations through demand-side measures or provide measurable system value in a manner consistent with the purpose of the DSM framework. Moreover, distributed solar PV systems already receive compensation through net metering, so by including them in the DSM funding, they are double compensated for ratepayer funds.[9] In short, behind-the-meter Solar-PV raises distinct policy, rate design, cost allocation, and equity issues that will be further discussed below and therefore should not be embedded in the DSM portfolio.

Accordingly, our high-level assessment is that E1's Plan is directionally correct in recognizing affordability but insufficiently disciplined in applying that principle to portfolio design. The Plan should be modified to impose stronger cost discipline on traditional EE, increase the emphasis on cost-effective and verifiable DR, establish an accelerated and accountable SE phase-in process, and remove Solar-PV from DSM funding. These changes would better align the DSM Plan with ratepayer affordability, system planning needs, and the evolving role of demand-side resources in Nova Scotia's electricity system.

Below, we discuss these points in further detail. All dollar values are expressed in CAD; any value converted from USD was done so using the Bank of Canada's 2025 USD to CAD exchange rate.

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[8] Id., Appendix A, Table 50, p. 86.; Id., Appendix A, Table 8, p. 28.

[9] See NSEB IR-3 M12783.

III. Affordability of E1's Preferred Plan

We understand that E1's Preferred Plan proposes to hold investment at the approved 2026 level of $63.75 million per year, with no annual inflation increases, for a total of $318.75 million over 2027–2031. E1 frames this revised budget as a deliberate affordability choice in response to current cost-of-living pressures, while acknowledging that the approach produces lower long-term savings than a plan more aligned with integrated resource planning (IRP) savings levels.[10] We also understand that NS Power's position during the stakeholder engagement process for the plan was that the total DSM portfolio investment should be based on the 2023–2026 budgets grown at inflation over the 2027-2031 period, while also shifting dollars away from traditional EE and Solar PV toward DR and SE.[11] For comparison, E1's own prior-period data show 2023–2026 actual/forecast DSM expenditures of $235.1 million, including $45.3 million in 2023, $65.7 million in 2024, $60.4 million in 2025, and the approved $63.75 million 2026 Extension, averaging to $58.8 million per year.[12] If that amount is escalated by 2 percent annually for 2027–2031, the NS Power budget concept would lead to $59.5M in 2027; $61.1M in 2028; $62.4M in 2029; $63.6M in 2030; and $64.9M in 2031, all totaling to $312M. This implies that the two budget numbers ($318.7M vs. $312M) are very close to each other.

While E1 and its consultant (Apex Analytics) did conduct a Jurisdictional Scan comparing E1's first year unit costs to other similar programs, it is unclear whether the peer group is sufficient. A 2026 American Council for an Energy-Efficient Economy (ACEEE) reveals that in 2024 the average lifetime cost of energy efficiency was $0.032/kWh with a median cost of $0.029/kWh.[13] In contrast, E1 states that the Preferred Plan's EE resource has a first-year unit cost of $0.66/kWh and, with a weighted average measure life of 12.3 years, results in an average lifetime unit cost of $0.05/kWh. This implies that E1 spends almost twice as much funding compared to these other jurisdictions included in the ACEEE analysis to deliver a single kWh of efficiency. E1 offers four explanations to the trend towards increased unit costs:

- E1 states that the portfolio is moving away from low-cost, high-volume lighting measures, especially LEDs, which historically produced large savings at very low unit costs. With residential LED baseline changes and the transition of the BNI lighting market, the portfolio

[10] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, Appendix A, Table 1, p. 1.

[11] Nova Scotia Power Comments to DSMAG, re: EfficiencyOne 2027-2031 DSM Plan Round 2 Modelling Results.

[12] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, Appendix A, Table 1, p. 4.

[13] Mike Specian and Alex Aquino, *Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth*, ACEEE, February 2026, p. 33.

shifts toward deeper and more complex measures such as building envelope upgrades, heat pumps, and custom commercial projects. E1 says those measures may deliver longer-term value, but they have higher first-year costs.

- E1 points to reduced evaluated savings for certain measures, particularly residential heat pumps. E1 says the 2024 DSM evaluation, based on billing analysis, reduced residential heat-pump savings by approximately 50%, meaning that the same or similar delivery effort produces fewer counted kWh savings.
- E1 states that program costs have increased because outside funding supports have ended, requiring E1 to increase incentives to maintain participation.
- E1 also cites broader inflationary pressures, including rising labour costs, supply-chain constraints, and higher material costs for efficiency equipment as contributing to higher DSM delivery costs generally.

While some of these factors are unique to Nova Scotia, depletion of LED-driven savings as well as broader inflationary pressures and supply chain constraints are similarly experienced in other jurisdictions; therefore, they do not fully explain why E1 is delivering one kWh of energy savings at twice the cost it takes for other jurisdictions. Neither the more holistic benchmarking, nor E1 jurisdictional review support the provided cost estimate. We would urge the Board to evaluate DSM plan affordability at two levels: total portfolio revenue requirement; and resource allocation within that budget. While the proposed budget may be directionally appropriate given the goal of limiting ratepayer impacts, its scope can be modified such that it reallocates funds from more expensive EE toward DR and SE where those resources have the potential to create higher system value.

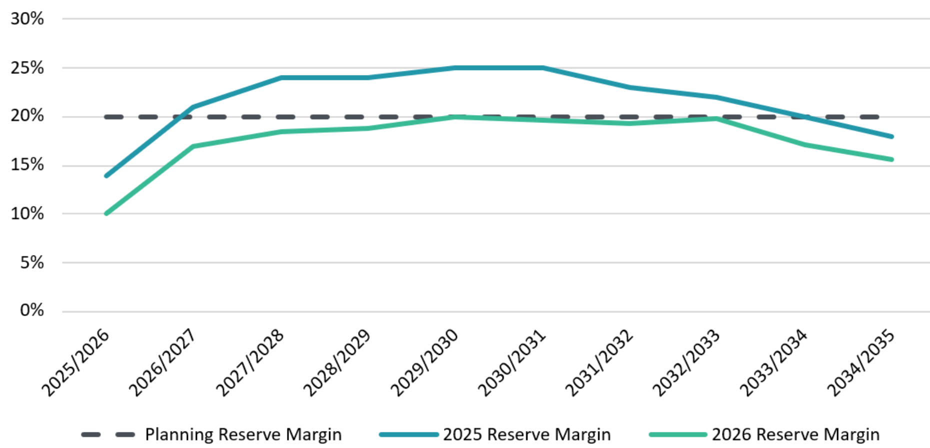
IV. Representation of Demand Response in E1's Preferred Plan

E1 presents the Preferred Plan as a deliberate affordability choice. It states that the Plan prioritizes short-term affordability and ratepayer value and focuses on services for which E1 has a proven record of implementation. That framing explains why E1 has narrowed the residential DR program, but it does not make the result reasonable. Affordability focus of the plan should not be used to justify the indefinite deferral of development of a resource that may reduce future capacity costs, especially when the system is becoming more winter-peaky and generation capacity headroom is tightening.

More specifically, E1's Preferred Plan Demand Response portfolio does not intend to enroll new residential customers and intends to add only a very limited number of additional BNI customers through 2031. While DR capacity from these customers is anticipated to grow nearly 50% from 16.3 MW in 2026 to 29.3 MW in 2031, the limited expansion of the Demand Response program to new customers, specifically the stagnant residential program, is a key weakness in the Preferred Plan as system capacity gets tighter. The issue is not that E1 excludes DR from the Preferred Plan. The issue is that E1 developed a DR program that spends materially on DR with no new residential customers, allows existing residential participation to decline, and relies entirely on BNI customers for capacity growth.

Forecasted peak load growth reinforces the need for a stronger commitment to DR strategy. Between the 2025 and 2026 load forecasts, peak load forecasts increased by 4%, reducing planned reserve margin (PRM) from 14% to 10% in 2026. While the PRM is set at 20% in Nova Scotia, based on the most recent load and capacity outlook, NS Power's reserve margin is at or below the 20% target in all years, with the tightest conditions occurring between 2026 and 2030, as it can be seen in Figure 1. In that context, DR should be aggressively pursued as a near-term capacity resource, not a small DSM program to be held in place until the next filing cycle. Currently DR capacity comprises only 0.3% of total peak load in 2026 and 1.3% of total peak load in 2031 suggesting greater penetration potential. Yet E1's Preferred Plan would leave residential DR participation declining and would rely almost entirely on a small increase in BNI participation for incremental capacity. This approach not only leaves a significant source of residential DR participation untapped but also heightens the risk profile of BNI DR impacts as PRMs decline rapidly, given the lack of class-level resource diversification within the DR portfolio.

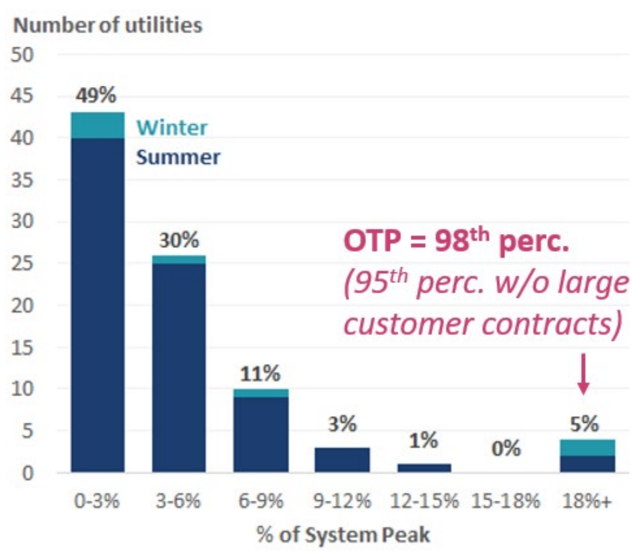
FIGURE 1: EXPECTED TRAJECTORY OF THE PLANNING RESERVE MARGIN IN NOVA SCOTIA



Source: Nova Scotia Power, 2025 10-Year System Outlook, July 14, 2025, Figure 20, pp. 46-47; Nova Scotia Power, 2026 Load Forecast, May 15, 2026, Table A2, pp. 108.

Figure 2 highlights a recent analysis of DR peak reduction capability of the US investor-owned utilities (IOUs). While the sample of winter-peaking IOUs is limited, other winter-peaking utilities like Otter Tail Power have achieved DR peak reduction capability of 28% peak reduction capability (13%, if large customer flexibility contracts excluded).[14] NS Power's achievable DR potential is likely far higher than the levels set in the current E1 plan.

FIGURE 2: 2023 PEAK REDUCTION CAPABILITY OF U.S. UTILITIES (% OF SYSTEM PEAK)



Source: The Brattle Group, 2026 Otter Tail Power Demand Response and Energy Efficiency Study, Appendix H, p. 12.

[14] The Brattle Group, *2026 Otter Tail Power Demand Response and Energy Efficiency Study*, Appendix H, p. 11. https://efiling.web.commerce.state.mn.us/documents/%7B10DA2C9E-0000-CA59-B6A8-D46B8558FF4F%7D/download?contentSequence=0&rowIndex=47.

Higher levels of investment now can also accelerate the market transformation and cut back the time necessary for impacts to scale in later years. E1 highlights "a growing role for residential demand response as part of the future electricity system" and that as households electrify "peak demand is expected to become an increasingly important system planning consideration." They further note that "expanding residential demand response capability during the upcoming DSM plan period would complement other system resources."[15] To stop the buildout of the residential program now could jeopardize its progress to date.

A. E1's Treatment of Demand Response

E1's Preferred Plan includes both residential DR with an annual budget of ~$2 million and BNI DR with an annual budget ranging from $3.1 million in 2027 to $4.4 million in 2031 with total Demand Response investment $29.1 million over five years. Between 2027 and 2031, the DR program is estimated to increase DR capacity from 21.1 MW in 2027 to 29.3 MW in 2031. DR capacity is heavily weighted towards BNI DR. Only 3.8 MW of DR capacity in 2031 is from residential DR and all growth in capacity is exclusively driven by BNI customers, primarily medium industrial customers, large general, and general service customers.

For residential households, E1's plan will add zero new customers and efforts will focus on existing household participation in the smart thermostat program that shifts load during winter peak events and direct load control for distributed hot water heaters (Eco Shift). Over time, the number of residential participants is expected to fall from 10,044 to 9,266 customers. Participation could fall faster if participants leave the program faster than expected or replace thermostats without re-enrollment.

For BNI, E1's Preferred Plan focuses on businesses further reducing load during peak events and providing financial incentives for DR capacity made available for those events under the Smart Synergy program. Customer participation is expected to grow from 169 customers in 2027 to 175 customers in 2031, an increase of 6 customers in total.

E1 has had challenges previously with DR program implementation and the Preferred Plan "focuses on the provision of services for which E1 has a proven track-record of successful implementation." Since the full rollout of the DR program in 2022, E1 has experienced high BNI participant opt-out and operational constraints, technology challenges with residential distributed hot water metering, and lower-than-expected adoption of smart thermostats and EV

[15] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, p. 29.

chargers. This period was described as a "development and learning phase" that "reflects the typical evolution of residential demand response programs across North America."[16]

DR program participation has recovered from these initial implementation challenges, but E1 still finds residential DR not cost-effective. E1's latest iteration of the DR program for its 2026–2031 plan is "established to be realistic and achievable while ensuring the overall Demand Response portfolio meets the cost-effectiveness threshold."[17] Table 1 presents E1's benefit-cost test results for the DR programs. Residential DR is not cost-effective, ranging from a PAC test of 0.9 in 2027 to a PAC test of 0.5 in 2028. Varying PAC test results over the plan years are mainly driven by underlying changes to the avoided cost of generation capacity which ranges from $250/kW-year in 2028 to $513/kw-year in 2027.

TABLE 1: PAC TEST RESULTS AND AVOIDED CAPACITY COSTS 2027–2031

Year	PAC—Res DR	PAC—BNI DR	PAC—Overall	Avoided T&D Capacity ($/kW-year)	Avoided Generation Capacity ($/kW-year)
2027	0.9	2.9	2.0	64	513
2028	0.5	1.6	1.2	65	250
2029	0.8	2.7	2.0	66	453
2030	0.7	2.3	1.7	68	380
2031	0.6	2.4	1.8	69	378

Source: EfficiencyOne, *Response to NSEB Information Request No. 12 (Regarding Section 3.3 "Demand Response" of the Application)*, filed in *M12780—EfficiencyOne (E1) 2027–2031 Demand Side Management (DSM) Resource Plan Application*, May 28, 2026, Table 2, p. 9.; EfficiencyOne, *2027–2031 DSM Resource Plan Application*, Appendix A, Table 8, p. 28.; EfficiencyOne, *Response to Synapse Energy Economics Information Request No. 62*, filed in *M12780—EfficiencyOne (E1) 2027–2031 Demand Side Management (DSM) Resource Plan Application*, May 28, 2026, Table 1, p. 2.

While individual programs in the portfolio do not need to have a PAC test greater than one, there must be justification for the inclusion of programs that are not individually cost effective. E1 justifies the inclusion of residential DR noting its key role in the future of the electricity system but has paused further rollout of the program "with the expectation that the residential program will be cost-effective in the future." Essentially, E1 argues that residential DR is not cost effective now so they will pause their program rollout until it becomes cost-effective in the future. However, the PAC test results reflect E1's *current* program design and costs and further assumes

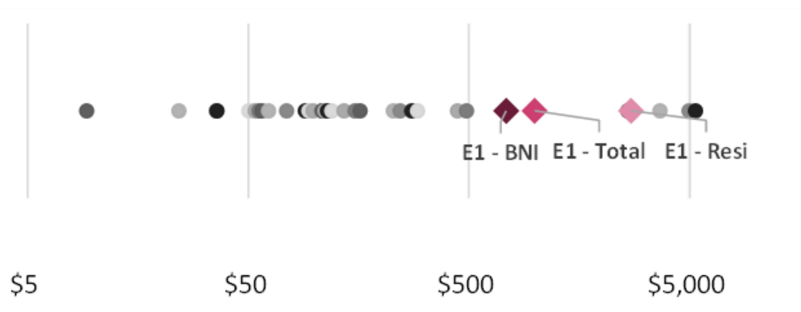
[16] Id., p.30.

[17] Id., Appendix A, p.17.

that residential programmatic stagnation will somehow result in the improved cost effectiveness. We discuss these two points below.

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

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 discussions with Ontario IESO's Demand Side Management Team "highlight[ed] a number of parallels relevant to E1's Residential Eco Shift program, including the time required to achieve sufficient participant scale; [and] the importance of improving participation rates and event performance over successive program

18 EfficiencyOne, *Response to NSEB Information Request No.12*, filed in *M12780—EfficiencyOne (E1) 2027–2031 Demand Side Management (DSM) Resource Plan Application*, May 28, 2026, p. 10.

seasons."[19] Through these discussions, E1 concluded that their Eco Shift program "is expected to reach cost-effectiveness under the Program Administrator Cost test within the next year". However, the IESO commentary explicitly highlights the need for continued investment into the program over successive programmatic seasons each year rather than stagnation of the program until it becomes cost-effective by itself. And this is exactly how the IESO's Peak Perks program gained momentum as we discuss in more detail below.

A Deeper Comparison to the IESO's Peak Perks Program

E1's filing highlights a very successful DR program from Ontario. Peak Perks is a smart thermostat DR program that scaled up very quickly and reached high customer satisfaction levels. E1 also notes that "in Ontario, the IESO implemented its Peak Perks program with the expectation that early years would focus on building participation, operational capability, and market awareness rather than immediate mature performance." However, this approach does not mean keeping the size and the scope of the program so minimal that it is virtually impossible to build practices around operational capability and market awareness, as seems to be the approach adopted by E1. More specifically, E1 is not planning to scale the residential DR program until cost effectiveness is reached (which they predict will likely happen in the next two years). However, the IESO continued to pursue the momentum on residential DR despite lack of cost-effectiveness in the early years, and by doing that they were able to scale up a program, which is soon expected to reach cost-effectiveness.

While E1 studied the Ontario IESO's Peak Perks program, we would recommend that E1 adopts the best practices in Peak Perks delivery and start implementing them in this DSM cycle. Peak Perks has become successful because it solved the two hardest residential DR problems at once: enrollment at scale and dependable load reduction with low customer friction. Its success is not just that customers were paid; it is that the program combined a simple offer, automated technology, credible comfort protections, and strong delivery partnerships. 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.[20] That matters because residential DR participation is often limited by attention, not just economics. The

[19] EfficiencyOne, *Response to Consumer Advocate Information Request No. 6*, filed in *M12780—EfficiencyOne (E1) 2027–2031 Demand Side Management (DSM) Resource Plan Application*, May 28, 2026, p. 2.

[20] *Cadmus, Peak Perks Program Evaluation Report* (prepared for Independent Electricity System Operator, Mar. 31, 2025), p. 1.

evaluation survey found that the prepaid Mastercard and energy-cost savings were the leading motivations, 80% selected them as top motivation/benefit drivers.[21]

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.[22]

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.[23]

4. **Customer control and comfort protections**: The program avoided the classic DR backlash problem by making events limited and reversible. Save on Energy says the thermostat may pre-cool before an event, is adjusted by no more than two degrees Celsius, lasts up to three hours, returns automatically afterward, and customers can opt out at any time. The evaluation found most surveyed respondents reported little to no comfort impact, and most rated comfort during events above 7 out of 10.[24]

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

It is important to note that Ontario IESO was able to implement Peak Perks because it was funded and directed as part of an expanded Conservation and Demand Management (CDM) framework;[25] it was forecast to be approximately cost-effective at launch, and cost-effectiveness was evaluated on a forward-looking and portfolio basis rather than as a strict *ex post* first-year

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[21] Id., p. 7.

[22] Save on Energy, "Peak Perks," accessed June 17, 2026, https://saveonenergy.ca/For-Your-Home/Peak-Perks

[23] Peak Perks Program Evaluation Report, Cadmus 2025, p. 35.

[24] Id., p. 8.

[25] In October 2022, IESO received a ministerial directive that increased the CDM budget by $342 million, from $692 million to just over $1 billion, to enable new and expanded CDM programming. IESO explicitly lists a "new residential demand response program" among the programs it was working to deliver in response to that directive. Independent Electricity System Operator, "2021–2024 Conservation and Demand Management Framework," accessed June 17, 2026, https://www.ieso.ca/CDM-MTR

pass/fail gate. The later PAC result shows that early realized economics were weaker than expected, but IESO could still justify continuation on the basis of scale-up, learning value, reliability value, and expected improvement as fixed start-up costs were amortized over a larger participant base.

B. Recommended Path Forward in Demand Response

NS Power's annual system peak has been increasing on average by around one percent per year since 2015. As weather conditions fluctuate and a greater share of households use electric space heating, the system peak will become increasing weather sensitive, and DR will become increasingly important in meeting peak demand. DR can meet capacity needs quickly through existing technologies, including smart thermostats, domestic hot water direct load control, BNI load curtailment, and device-based load control.

E1's Plan recognizes the potential of DR, but it still treats DR as a relatively narrow program offering rather than as an increasingly important system resource. That is the wrong framing. As Nova Scotia electrifies heating and transportation, the system will need more than passive EE savings. It will need flexible demand that can be called on during high-value hours, especially during winter peaks. DR can reduce system peak, defer or avoid capacity investments, support resource adequacy, provide operational flexibility during extreme weather, and hedge against uncertainty in load growth and generation buildout. Those attributes make DR directly relevant to affordability and reliability, not just to DSM portfolio accounting.

The distinction between DR and traditional EE matters. EE can reduce peak demand, but those savings are generally passive and statistical. Dispatchable DR is different. It can be measured after an event, evaluated against performance expectations, and, if the rules are developed properly, accredited as a capacity resource. That is why E1's treatment of DR as something to maintain at limited scale until it becomes easier or more cost-effective is not sufficient. A mature market needs to be actively developed, so passively waiting for the market to mature by itself will not result in the best outcome. If E1 does not invest in better residential DR delivery, stronger customer acquisition, cleaner technology integration, and more rigorous performance measurement in this DSM cycle, there is little reason to expect the facts to look materially better in the next one.

The issue is not that DR is inherently uneconomic or that residential DR should be abandoned because the current PAC results are weak. The issue is that E1's current residential DR design is too limited, too expensive, and too passive in its approach to program development. A plan that enrolls no new residential customers, allows participation to decline, and then assumes cost-effectiveness will improve later is not a credible market transformation strategy. The Ontario IESO's Peak Perks example points in the opposite direction: scale, simple incentives, automated participation, device-partner enrollment channels, customer comfort protections, and repeated event-season learning are what improve performance and spread fixed costs over a broader participant base. E1 should be required to adopt those lessons now, not merely cite them as a reason to wait.

A modified Plan should therefore require E1 to develop DR as a dispatchable system resource with clear performance, accreditation, and cost-effectiveness metrics. That should include a careful assessment of delivery models from other jurisdictions, including incentive levels, customer acquisition strategies, aggregator compensation structures, device-partner roles, and pay-for-performance mechanisms. E1 should undertake a new DR potential study that identifies and prioritizes resources based on winter peak value, including the relative potential of smart thermostats, domestic hot water control, BNI curtailment, and other controllable loads. That study would be instrumental for guiding expectations around customer segments, event performance, attrition, device health, locational value, and the costs required to turn enrolled devices into dependable capacity.

BNI Smart Synergy should be scaled where it is cost-effective, but E1 should not let BNI growth substitute for a real residential DR strategy. The BNI portfolio is important, but it is concentrated in a small number of customers and raises separate questions about incrementality, availability, and compensation. Residential DR is harder to build, but it is also important for a winter-peaking system with growing electrification of space heating, water heating and transportation. The Plan should therefore expand the scope of residential DR, with priority placed on smart thermostats and domestic hot water direct load control, because those are the opportune near-term pathways for automated winter peak reduction. Programs that have not demonstrated scalable value, such as home battery and EV smart charging integration in their current form, should not distract from getting the core DR resources right.

Finally, E1 should be required to report DR performance in a way that allows the resource to be used in system planning and operations. That means annual accreditation and performance reporting after each peak season, opt-outs, attrition, device failures, customer compensation, delivery costs, and verified peak reduction. Without a comprehensive performance evaluation, DR will continue to sit in an uncomfortable middle ground counted as a promising future resource but not managed with the rigor needed for NS Power or the Board to rely on it. The modified

Plan should close that gap. DR should be treated as a real capacity resource, and E1 should be held to the delivery, measurement, and cost-control standards that come with that role.

V. Representation of Strategic Electrification in E1's Preferred Plan

SE is now expressly recognized within Nova Scotia's statutory DSM framework. The Public Utilities Act, which was amended in 2022, defines DSM to include "strategic electrification of energy end uses currently powered by fossil fuels in a manner that reduces overall greenhouse-gas emissions and electricity costs."[26] The Board has interpreted this language as requiring both elements to be satisfied: SE must reduce GHG emissions and reduce electricity costs for customers.[27] This conjunctive requirement is key, as both factors affect the likelihood of strategic electrification programs passing the Board's requirements for DSM program approval. Our discussion below expands on this requirement as it pertains to E1's DSM application.

Electrification of space heating, water heating, transportation, and other end uses is expected to play an important role in meeting Nova Scotia's climate and energy objectives. E1 acknowledges this broader policy context, noting that both NS Power's 2022 Evergreen IRP and Nova Scotia's Clean Power Plan identify electrification as important to achieving provincial climate goals.[28] Therefore, it is crucial to include SE in this plan to advance these goals.

A. E1's Treatment of Strategic Electrification

E1 states that it took its role in advancing SE seriously and considered whether SE could be included in the 2027–2031 DSM Plan. E1's modelling focused on building electrification measures where it believed it could leverage existing partnerships, program infrastructure, and delivery expertise. E1 reviewed multiple SE scenarios, including heat pump water heaters, cold-climate heat pumps for space heating, hybrid heating measures, and custom measures. E1 also states

[26] *Public Utilities Act*, R.S.N.S. 1989, c. 380, s. 79A(b)(iv).

[27] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, p. 35.

[28] Id., p. 34.

that it considered hybrid heating and worked collaboratively with Eastward Energy and NS Power during the modelling process.[29]

E1 notes that they evaluated these SE scenarios using the Board-approved modified PAC test, which includes increased utility revenues associated with incremental electrification load in addition to the other PAC costs and benefits. They found that all modeled SE scenarios failed to reduce electricity costs for customers under this test. E1 further states that "even under optimal assumptions where there are no peak impacts arising from the strategic electrification measures, they remained not cost-effective."[30]

E1 separately assessed GHG impacts using emissions information from NS Power's 2022 Evergreen IRP because long-run marginal emissions rates were not available. E1 states that it requested long-run marginal emissions rates from NS Power in December 2025 and followed up in February 2026 but was advised that this information was not yet available and that NS Power and the IESO Nova Scotia were working to develop the methodology. E1 noted that while strategic electrification measures can reduce GHG emissions, because the measures modeled did not reduce electricity costs, it excluded strategic electrification as a DSM resource from the Preferred Plan.[31]

Instead of including strategic electrification as a resource, E1 proposes to pursue it through the Enabling Strategies by funding support for market research and technology assessment, pilot programs, collaboration with the IESO Nova Scotia in future IRP development, and continued evaluation of how changing avoided costs and capacity values may improve strategic electrification economics in *future plan periods*. Finally, E1 committed to reporting annually on strategic electrification research activities and findings as part of its Annual Progress Reports.[32]

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29 Id., p. 35.

30 Ibid.

31 Ibid.

32 Id., p. 35-36.

B. Brattle's Assessment of E1's Treatment of Strategic Electrification

1. Strategic electrification can be a beneficial DSM resource when it is targeted, controlled, and coordinated with system planning.

E1 states in its application that the proposed SE programs, as designed, reduced GHG emissions but did not pass the Board's modified-PAC test and thus were excluded from E1's preferred DSM plan. E1 relegated SE efforts to additional development and research within the Enabling Strategies of the budget, noting that this budget will support:

- Market research and technology assessment to identify emerging SE opportunities with improved economics;
- Pilot programs to test delivery approaches and gather real-world performance data;
- Collaboration with the IESO Nova Scotia on future IRP development to better quantify system benefits;
- Ongoing evaluation of how changes to avoided costs, particularly capacity values, may improve cost-effectiveness of SE in *future plan periods.*

In addition, E1 notes that they will report annually on SE related activities and findings through Annual Progress Reports. While the proposal to follow-up and refine on existing efforts is noteworthy, the first two bullets indicate that the SE programs that E1 tested may lack the program design features of more successful programs implemented elsewhere; the latter two bullets indicate that E1's existing methodology and/or data availability is an issue.

While we detail concerns with the use of the modified-PAC test to screen SE programs below, E1's concession that there is room for improvement in the quality of the data used for modeling SE programs means that modified-PAC test results for the modeled strategic electrification programs may not be truly representative of the programs' overall benefits. 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.

Successful cost-effectiveness outcomes within the existing Board-approved framework can be achieved by designing proposed electrification programs around flexibility such that they eliminate or reduce the peak impacts. These benefits can be realized by shifting loads away from higher-cost hours; encouraging peak demand reduction during system critical conditions through passive or direct control; or targeting deployment to unconstrained parts of the distribution system. For instance, an EV managed charging program, or electric water heating program which can shift the load to off-peak hours, could improve grid utilization and defer expensive incremental grid investment. Integrating flexibility into the design of SE programs is particularly relevant because E1's own application recognizes that demand response and flexible demand-side resources will become increasingly important as the electricity system evolves in response to electrification, environmental compliance, and changing market conditions.[33] Therefore, to the extent that program design puts SE at a disadvantage, E1 must re-design these programs to emulate those that are proven to provide system benefits.

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

For these reasons, E1's conclusion that SE cannot be included as a resource under the current plan should not end the inquiry. The Board need not require E1 to fund uneconomic SE measures under the current modified PAC framework. However, the Board should also not allow SE to remain a research-only activity for the full 2027–2031 plan term. At a minimum, the evidence supports requiring E1 to develop a phase-in pathway that identifies more effective candidate measures including integrated flexibility and load control features while continuing to refine its data gathering process for the purposes of cost-effectiveness calculations.

Crucially, the Board must also require E1 to consider transportation electrification measures into any proposed set of strategic electrification programs. Managed EV charging programs, both passive and active, have been shown to be effective at mitigating distribution system constraints and deferring incremental investment, thereby applying downward rate pressure in the near term. For instance, Newfoundland Power's 2021–2025 Electrification, Conservation and Demand

[33] Id., p. 28–29.

Management Plan recognized the benefits of managed EV charging.[34] The plan notes that "demand management is essential to realizing the full benefits of EV adoption" as unmanaged charging has the potential to contribute to capacity-related system cost.[35] The plan also shows that managed charging passes the cost-effectiveness test while unmanaged charging fails it.[36] Therefore, there is evidence from at least one other Canadian jurisdiction that the incorporation of managed EV charging programs can enhance the cost-effectiveness of a broader electrification portfolio.

2. It is highly unlikely that E1 will be able to develop a robust strategic electrification portfolio that will be cost-effective under the modified PAC.

The cost-effectiveness results of E1's proposed SE programs reveals a second issue: the existing cost-effectiveness framework. We understand the Board previously rejected the use of a Jurisdictional Specific Test proposed by E1 as the primary test for DSM Benefit Cost Analysis (BCA).[37] Instead, the Board directed a modified PAC test, specifically for SE initiatives, which alters the traditional PAC test by incorporating incremental or lost revenues (depending on the program type) from SE programs. By accounting for the change in revenues from electrification initiatives, this modified-PAC test becomes equivalent to a traditional Rate Impact Measure (RIM) test. In this proceeding, E1 adopted this modified-PAC test to show that no SE initiatives, as designed, were able to reduce both electricity costs and GHG emissions under that modified PAC test.[38] It is instrumental to unpack benefit and cost categories included in the modified PAC to demonstrate why it is very unlikely for an SE program to pass this test:

1. The PAC test is fundamentally a utility-system or program-administrator test. It asks whether the utility-system benefits of a DSM resource exceed the utility-system costs incurred to procure it. For conventional energy efficiency, the PAC framework is often straightforward because the measure reduces electric consumption and therefore produces avoided electric energy, capacity, transmission, distribution, or other electric-system costs. For SE, the measure generally increases electric consumption because it often replaces a fossil-fueled or relatively high emission end use with an electric alternative, which may lead to *incremental* energy, capacity, or delivery related electricity costs from the perspective of the utility-system

[34] Newfoundland Labrador Hydro and Newfoundland Power, *Electrification, Conservation and Demand Management Plan 2021-2025,* 2021.

[35] Id., p. 11.

[36] Id., p. 107-110.

[37] Board Decision, Case M12282, December 10, 2025, ¶ 217.

[38] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, p. 16.

or program administrator. The Board-approved *modified* PAC attempts to specifically address the requirement that the SE should be reducing electricity costs, by adding incremental utility revenues as a benefit. That adjustment may be responsive to the Board's interpretation of the Public Utilities Act, but it also makes the test equivalent to RIM test. In Table 2 below, we present benefit and cost impacts that would be included the modified PAC, and how each impact would affect the test outcome for an electrification program that increases customer electric demand.

TABLE 2: BENEFIT AND COST CATEGORIES INCLUDED IN THE MODIFIED PAC TEST

Benefits	Costs
Energy related costs avoided by utility (negative)	Program overhead costs (negative)
Generation capacity related costs avoided by utility (negative)	Program administrator incentive costs (negative)
T&D capacity related costs avoided by utility (negative)	Program administrator installation costs (negative)
Increased revenue due to increased energy consumption **(positive)**	

As this table makes clear, the only benefit included in the test is <u>increased revenue from higher electricity bills</u>. For the test to produce a benefit-cost ratio greater than 1.0, this revenue increase would need to exceed the sum of all other factors, each of which reflects a negative impact (i.e., an increase in electric system costs). What also follows from this table is that it is highly unlikely for E1 to be able to develop a robust SE portfolio that will have high enough revenue impact to offset all other costs introduced by the program.

2. Another challenge is the exclusion of other energy benefits from the scope of the test due to legislative requirement. The National Standard Practices Manual (NSPM) explains that electrification may add costs to the electric grid and can only be found cost-effective where the applicable BCA test includes relevant non-electric system impacts, including reductions in gasoline, diesel, natural gas, fuel oil, propane, and other fuels.[39] *In practical terms, this means that a test focused only on electric-system costs and electric-system benefits will tend to treat strategic electrification as a cost adder, while omitting much of the value that motivated the measure in the first place*.

[39] National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (2026), Chapter 12, p. 12-8.

> This does not mean the Board was wrong to adopt a modified PAC for strategic electrification. The Board was interpreting Nova Scotia's statute, and the statutory definition of SE expressly requires both GHG reductions *and* electricity-cost reductions. While we understand that the modified PAC is a jurisdiction-specific implementation of statutory language, it is not a standard best-practice BCA framework for accounting for all customer benefits of electrification and that it does not credit strategic electrification measures for a sizable portion of benefits they generate.

In November 2025, The Brattle Group published a report on findings from a decade of beneficial electrification in the US.[40] This report evaluated beneficial electrification across four pillars: cost savings, product quality and customer experience, grid resilience, and environmental performance. Under this framework, *electrification is beneficial when it improves one or more of those pillars without materially detracting from the others*. While this definition is not perfectly aligned with the Board's criteria for SE, it is an example of emerging frameworks that comprehensively account for the benefits offered by such programs.[41] The study reports that electrification has already delivered overall energy savings in multiple applications. For space heating, households switching to heat pumps in many jurisdictions have reduced energy bills, particularly where the displaced fuel is fuel oil, propane, or electric resistance heating. Brattle estimates cumulative U.S. heat pump operational savings of roughly $21 billion to $49 billion for consumers shifting from non-gas fossil heating sources between 2009 and 2024.[42] For battery electric vehicles, Brattle estimates cumulative owner savings of $18 billion to $24 billion between 2016 and 2023, driven by improved fuel economy, lower fuel costs, and lower maintenance costs.[43] These customer savings should be understood as comprehensive <u>net</u> <u>energy cost savings</u>: a customer may consume more electricity after electrification, but still experience lower total household energy costs after accounting for avoided fuel oil, propane, gasoline, diesel, or other fossil-fuel expenditures. That would be an overall beneficial outcome for the customer, even if their electricity bill increases.

Emission benefits are not explicitly being accounted for in the modified PAC test. This matters because the statutory definition of SE requires reductions in "*overall* greenhouse gas emissions," not merely reductions in electric-system emissions. A comprehensive emissions analysis for a

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[40] Ryan Hledik, Long Lam, and Cristina Crespo Montañés, *A Decade of Beneficial Electrification: Progress and the Path Ahead*, The Brattle Group, prepared for the Beneficial Electrification League, November 2025, https://www.brattle.com/wp-content/uploads/2025/11/A-Decade-of-Beneficial-Electrification-Progress-and-the-Path-Ahead.pdf

[41] Id., p. 4.

[42] Id., p. 5.

[43] Id., p. 16.

heat pump, heat pump water heater, or EV charging measure requires comparing incremental electric-system emissions against avoided emissions from the displaced fossil fuel. The NSPM likewise notes that the net GHG impact of electrification requires comparing emissions from increased electric generation with emissions avoided from reduced use of other fuels.[44] E1 states that the modeled SE measures reduced GHG emissions based on available emissions data but failed the modified PAC because of increased electricity costs to ratepayers.[45] This acknowledgement of emissions reductions but its absence in the cost-effectiveness framework is evidence that the modified-PAC test, in its current form, provides a structural disadvantage to SE because there is no way to account for the overall benefits within the framework.

3. Cost-Effectiveness Frameworks in Other Jurisdictions

Looking south of the Canadian border, there is also comparative support for using broader tests to evaluate emissions-related and fuel-switching benefits, especially among US States with aggressive decarbonization and clean energy goals. The 2025 ACEEE State Energy Efficiency Scorecard, which ranks US states based on their policies and programs to advance DSM, including beneficial electrification, lists information on the cost-effectiveness tests used by each state. Among the top-ten ranked states, summarized in the Table 3 below, RIM and UCT are uncommon as a primary DSM screening test. Where RIM and UCT are used, it appears to be secondary, meant to inform the results of the cost-effectiveness test but not by itself meant to be a barometer of cost-effectiveness. Emissions benefits appear in broader SCT, or jurisdiction-specific test (JST) BCA frameworks. While emissions benefits are typically not directly included within a TRC framework, savings from overall cost reductions in avoided/other fuels are included.

[44] National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (2026), Ch. 6, p. 6–27.

[45] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, p. 35.

TABLE 3: 2025 ACEEE DSM SCORECARD TOP 10 STATES AND DSM SCREENING TESTS

Ranking	State	Primary DSM Screening Test	Secondary DSM Screening Test
1	California	TRC	UCT, RIM
2	Massachusetts	TRC	N/A
3	New York	SCT	UCT, RIM
4	Maryland	JST	PCT, RIM, TRC, UCT
5	Vermont	SCT	UCT
6	Washington	TRC	UCT
7	Colorado	mTRC	SCT, UCT, PCT, RIM
8	New Jersey	JST	PCT, IM, SCT, TRC, UCT
9	Oregon	TRC, UCT	N/A
10	Maine	JST	UCT

Source: Database of Screening Practices, ACEEE, assessed 6/16/2026.

On the other hand, Québec is the only Canadian Province that uses only a TRC test as the primary cost-effectiveness test for electric programs.[46] Newfoundland and Labrador, and Saskatchewan use both the TRC and Program Administrator Cost Test (PACT) for electric programs. All other Canadian Provinces uses a PACT or UCT as their sole primary cost-effectiveness test. However, a 2024 report by Efficiency Canada discusses how traditional demand-side management and cost-effectiveness frameworks can hinder progress for beneficial electrification. The report notes that traditional DSM assessment frameworks can lead to the creation of "fuel silos" that draw strict boundaries for programs implemented in the electric or natural gas system.[47] Within this report, the authors reference Nova Scotia's update to the Public Utilities Act and note that specifying "electricity costs" within the legislative mandate leaves some ambiguity over measures that may reduce overall energy costs. Citing other jurisdictions, the authors note an attempt by Newfoundland utilities to update the cost-effectiveness test to include a modified TRC that considered customer cost savings from lower non-electric fuel and maintenance costs. The regulator ultimately rejected the proposal citing its contradiction to the Board's cost reducing mandate. The authors noted that the decision stalled the incorporation of electrification into traditional DSM but also recorded quicker approval of electrification programs that were funded through federal government programs outside of ratepayer funded DSM. On the other hand,

[46] Efficiency Canada Policy Tacking System, Cost-effectiveness testing - Electricity, accessed June 22, 2026, https://database.efficiencycanada.org/policy/energy-efficiency-programs/cost-effectiveness-testing-electricity

[47] Efficiency Canada and Carleton University, B*reaking Fuel Silos in Demand Side Management,* Policy Options to Align Energy Efficiency with Net-Zero Emissions Across All Fuels, 2024.

Ontario provides an example of a more expansive definition used by the IESO for beneficial electrification as "measures which involve using electricity to reduce *overall emissions in Ontario* in a manner that minimizes electricity system impacts." Ontario's focus on overall Province emissions as well as the *minimization of electricity system impacts* rather than costs alone represents a holistic view of the impact electrification can have on the broader electric system.

The Board has already recognized the NSPM as a useful framework for developing BCA tests, while also concluding that Nova Scotia's statute constrains the selection of the primary test.[48] We understand that there is not much scope for change in the test given the current legislature. However, based on the discussion above, we believe there is not a robust path for comprehensive strategic electrification in Nova Scotia at this time.

C. Recommended Path Forward in Strategic Electrification

As we discuss in detail above, the modified PAC test creates a structural barrier for SE because it largely credits only increased utility revenue while excluding many non-electric energy savings and broader customer benefits. Although the Board may be constrained by the statutory requirement to focus on electricity-cost reductions, it should not interpret failed modified-PAC results as proof that SE lacks value. The recommended approach is therefore to keep the current statutory framework in view, but require E1 to refine program design, improve cost-effectiveness inputs, evaluate flexibility and emissions impacts more comprehensively, and develop a practical path for SE rather than deferring the entire resource category.

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

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

48 *Application by EfficiencyOne for Approval of a New Benefit-Cost Analysis Test for Evaluating Demand Side Management Plans*, 2025 NSEB 18, ¶ 17–18 and ¶ 128–142, Dec. 10, 2025.

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

VI. Inclusion of Solar PV in E1's Preferred Plan

E1's Preferred Plan includes a new residential Solar PV program. Unlike strategic electrification, which E1 excluded as a resource and instead proposed to focus research and development efforts within Enabling Strategies, Solar PV is a new program included specifically in the proposed DSM portfolio. E1 describes the offering as modest in scale and targeted exclusively to residents in Mi'kmaw communities. It is coordinated with the Mi'kmaw New Home Construction program component and furthers the legislative objectives of Environmental Goals and Climate Change Reduction Act to prioritize equitable access and benefits for low-income and for historically underserved Nova Scotians.

A. E1's Inclusion of Rooftop Solar PV Programs in the Preferred Plan

E1 reports that customer-sited Solar PV falls within the statutory definition of DSM under section 79A(b)(v) of the Public Utilities Act, which includes activities relating to "the delivery of a reduction in the amount of electrical energy or capacity that Nova Scotia Power Incorporated would otherwise be required to supply to its customers."[49] E1 acknowledges that incidental excess generation may flow to the grid under net metering arrangements, but argues that this does not alter the fundamental character of the resource. In E1's view, the program is designed and sized to reduce customer demand, the customer receives no compensation beyond offsetting its own consumption, and the primary effect is a reduction in the electrical energy NS Power would otherwise be required to supply.[50]

The proposed program is limited to Mi'kmaw communities. E1 states that this targeted approach is intended to address documented barriers to participation in DSM programs, including access to capital, housing-related issues in reserve communities, and historical underinvestment in

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[49] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, p. 3.

[50] Id., p. 33.

energy infrastructure. E1 also notes that the program, as designed, aligns with the Environmental Goals and Climate Change Reduction Act, the Energy and Regulatory Boards Act, and broader reconciliation objectives.[51] Importantly, E1 acknowledges that any expansion of similar Solar PV programs to other customer segments would be subject to the Board's cost-effectiveness requirements and approval.[52]

In the Preferred Plan, the Solar PV program includes 200 installations over the five-year plan period, representing 0.9 percent of total DSM investment funding. The portfolio-level results show 2 MW of installed Solar PV capacity, 1.7 GWh of first-year solar PV generation, 52.2 GWh of lifetime Solar PV generation, and approximately $2.8 million in program investment.[53] Based on the PAC-test results presented by E1, the proposed Solar PV program exhibits a PAC test ratio of 1.1, implying that it is marginally cost-effective based on E1's methodology.

B. Brattle's Assessment of Inclusion of Rooftop Solar PV's in E1's Preferred Plan

E1's proposed Solar PV offering raises two distinct questions that should be analyzed separately. The first is whether customer-sited Solar PV can be interpreted to fall within the broad statutory definition of DSM under section 79A of the Public Utilities Act. The second is whether, as a matter of DSM resource planning and ratepayer-funded portfolio design, standalone Solar PV should be treated as an appropriate DSM resource in Nova Scotia's current system context. In our view, the latter question is the more important one for the Board to consider.

On the first question, we understand E1's position to be that behind-the-meter Solar PV can reduce the amount of electrical energy NS Power would otherwise be required to supply to participating customers. That argument has a textual basis in the statutory DSM definition, which includes "activities, programs, or plans relating to the delivery of a reduction in the *amount of electrical energy* or capacity that Nova Scotia Power Incorporated would otherwise be required to supply".[54] We do not dismiss that argument. Customer-owned Solar PV can reduce a participating customer's annual net energy purchases from the utility, and E1's proposed program is targeted, modest in scale, and designed to provide benefits to Mi'kmaw communities,

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[51] Id., p. 33-34.

[52] Ibid.

[53] Id., p. 34; Id., Table 9, p. 58–71.

[54] *Public Utilities Act*, R.S.N.S. 1989, c. 380, s. 79A(b)(v)

which may also help further the Province's legislative objectives by providing equitable access and benefits for low-income and for marginalized Nova Scotians.[55]

However, even if customer-owned Solar PV can be read to fit within the statutory language as an energy-reduction measure, it does not cleanly fit within the core purpose of DSM as a resource for reducing or managing customer demand. While customer-owned Solar PV may reduce the customer's reliance on utility-provided energy (kWh), it does not necessarily reduce "…the capacity that Nova Scotia Power Incorporated would otherwise be required to supply" as articulated in the statute, when NS Power's system is most constrained. This distinction matters because Nova Scotia's planning need is not limited to annual energy. The record shows that NS Power is facing material winter peak and resource adequacy challenges, and that the system value of DSM increasingly depends on whether a resource reduces firm capacity needs during winter peak and reliability-risk hours.[56]

The 2026 Load Forecast reinforces this point. NS Power forecasts both annual energy requirements and system peak demand, and states that customer growth, electrification of heating, and increased EV sales will increase peak demand while DSM and DR activities will reduce it. The 2026 Load Forecast projects system peak growth of 1.1 percent annually from 2026 to 2036 and states that the near-term peak forecast is approximately 3.1 percent higher than in the 2025 Load Forecast due to model adjustments reflecting the highest recorded system peak, which occurred on January 25, 2026.[57] The same report states that Nova Scotia's total system peak occurs in the December through February period because of weather-sensitive load.[58]

The capacity context is also reflected in NS Power's 2025 10-Year System Outlook. The System Outlook is the Nova Scotia Power System Operator's ("NSPSO") annual assessment of NS Power's system capacity and resource adequacy.[59] In that report, NS Power explains that variable renewable resources such as wind and solar are producing more energy, but due to their intermittent nature provide less firm capacity as a percentage of nameplate capacity than conventional generation resources. As a result, NS Power states that the majority of the system's firm capacity requirement is met with conventional units, while variable renewable resources displace energy output.[60]

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[55] EfficiencyOne, *2027–2031 DSM Resource Plan Application*, p.32-34.

[56] Nova Scotia Power, 2025 10-Year System Outlook, July 14, 2025.

[57] Nova Scotia Power, 2026 Load Forecast, May 15, 2026, p. 10-11.

[58] Id., p. 83.

[59] Nova Scotia Power, 2025 10-Year System Outlook, July 14, 2025, p. 5.

[60] Id., p. 11.

The reserve-margin analysis in the System Outlook further supports this concern. NS Power applies a required planning reserve margin equal to 20 percent of firm peak load. The outlook shows a deficit of 134 MW in winter 2025/2026, near-term reliance on new firm additions, and a tightening reserve position later in the period, with reserve margin declining to 20 percent by 2033/2034 and 18 percent by 2034/2035.[61] This observation is presented above in Figure 1. This is not a system context in which all annual kWh reductions should be treated as equivalent. A DSM resource that reduces annual energy but provides little or no winter coincident peak reduction has different reliability planning value than a DSM resource that reliably reduces firm peak or can be dispatched during system risk hours.

NS Power's own treatment of Solar PV in the 2026 Load Forecast is consistent with this distinction. In the Load Forecast, small-scale net-metered solar is treated as a reduction in residential and commercial load, and NS Power forecasts total installed net-metered solar capacity of 655 MW by 2036. But *NS Power expressly assigns no reduction in peak demand, stating that "there is no forecast reduction in NS Power peak demand, as solar generation occurs at times non-coincident with NS Power's system peak*."[62] The forecast table likewise shows solar reducing energy but contributing 0 MW of peak reduction in every forecast year.[63]

This treatment aligns with NS Power's resource adequacy evidence. In the 2025 System Outlook, NS Power states that solar has very limited ELCC in Nova Scotia because of poor correlation with net peak load hours, which primarily occur on winter evenings, and that beyond initial penetrations of solar capacity, the marginal capacity value declines to zero.[64] The System Outlook's resource plan also assigns NS Community Solar 25 MW of installed capacity but 0 MW of firm capacity, with only a 3 MW diversity credit shown in the additions-and-retirements table.[65]

Residential net metering data provided by NS Power also corroborates the significant drop in generation output from customer-owned solar PV assets during the winter months. Table 4 summarizes the monthly output from residential net metering customers from the 2025 calendar year. It shows that while these customer-owned assets produced energy in all months, the generation output dropped significantly in the winter months of November, December, January and February, when the likelihood of the system peak is highest. The effective capacity factor for

[61] Id., p. 46–47.

[62] Nova Scotia Power, 2026 Load Forecast, May 15, 2026, p. 48.

[63] Id., p. 49.

[64] Nova Scotia Power, 2025 10-Year System Outlook, July 14, 2025, p. 44.

[65] Id., p. 17–18.

the solar PV units ranges from merely 3% - 6% during these months, compared with a range of roughly 16% - 20% during the summer months. This essentially means that the customer-owned solar PV is ineffective in meeting customer peak demand during the months when NS Power is most constrained for capacity. Therefore, NS Power's planning assumptions and monthly generation data support the conclusion that standalone Solar PV may provide annual energy and contribution to decarbonization value, but it has limited, if not null, value as a material winter capacity resource in the DSM portfolio absent specific evidence of coincident peak performance.

TABLE 4: NS POWER RESIDENTIAL NET METERING CONSUMPTION AND GENERATION MONTHLY PATTERNS

Month	Consumption From Grid (kWh)	BTM Solar Generation (kWh)	Energy Exported to Grid (kWh)	Total Solar Generation (kWh)	Solar Capacity Factor (%)
Jan	2001	103	103	207	3%
Feb	1722	148	209	356	6%
Mar	1381	185	401	586	9%
Apr	975	335	779	1114	18%
May	695	348	934	1282	20%
Jun	601	383	850	1233	20%
July	649	407	858	1265	20%
Aug	664	352	810	1162	18%
Sep	635	271	712	983	16%
Oct	827	207	543	749	12%
Nov	1200	103	161	264	4%
Dec	1860	78	126	204	3%
Total	13,209	2,920*	6,485*	9,405*	

Sources and Notes: Monthly generation and export data provided by NS Power. *Values are in alignment with annual totals provided in NSPI Response to NSEB IR-4, Page 3 of 4, Exhibit N-2, M12783 – Regulation 3.6 – 2025 Net Metering Report, filed May 26, 2026.

Nova Scotia is not alone in recognizing limitations in the ability of Solar PV to address resource adequacy concerns. The comparable evidence from other winter-peaking jurisdictions supports a similar conclusion. Official planning materials from Manitoba, New Brunswick, and Prince Edward Island, support the proposition that standalone Solar PV generally provides limited dependable winter peak capacity unless paired with storage, dispatchable controls, or another firming resource. Manitoba Hydro states that solar does not provide firm, consistent, dependable electrical capacity during winter peak times.[66] NB Power's 2023 IRP, based on an E3 ELCC study, states that because New Brunswick's probable winter peak usually occurs from 7 to 8 am, expected solar generation would be minimal and would contribute almost nothing to reliability during peak load times.[67] Maritime Electric assumes solar generation is zero at system peak and states that solar cannot be counted toward capacity requirements because Prince Edward Island's (PEI's) winter peak typically occurs after sunset.[68]

This comparable evidence should be used carefully. It does not show that Solar PV lacks customer value, or that it should not be supported further by the Province's public policy goals. The aspect under consideration is the use of DSM funding given Nova Scotia's emphasis on near and long-term capacity constraints, where the relevant objectives are system peak (specifically winter peak) reduction, capacity deferral, and resource adequacy. Standalone Solar PV is an ineffective capacity resource unless it is paired with dispatchable storage with controls to dramatically improve its winter peaking capacity and make it available during the actual system risk hours. Solar-plus-storage may be a different resource, but its capacity value depends on storage duration, controls, dispatchability, and measurement.

The equity rationale for E1's proposal should be considered separately from the capacity rationale. We recognize the importance of ensuring that Mi'kmaw communities and other historically underserved communities are not left behind in the clean energy transition. E1's proposed offering appears to be targeted to Mi'kmaw communities and modest in scale, and those are relevant considerations. Equity, affordability, and community energy benefits may justify a targeted intervention even where the resource does not provide material capacity value. But that rationale should be stated transparently rather than treating standalone Solar PV as if it were a conventional DSM resource.

The evidence provided above, from Nova Scotia's own planning, reliability and load forecast documentation, as well as similar reports from other winter-peaking Canadian jurisdictions, points to the limited capacity value that Solar PV offers as a traditional DSM resource. However, given the equity basis provided by E1, similar Solar PV programs could be supported through a non-DSM funding mechanism, such as a government-funded equity program, community energy program, distributed energy resource program, or other targeted clean-energy funding sources.

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66 Manitoba Hydro, 2025 Integrated Resource Plan, Round 1 Questions and Answers.

67 New Brunswick Power Corporation, *2023 Integrated Resource Plan*, 2023, Sec.9.3, p. 45.

68 Maritime Electric, *Application for On-Island Capacity for Security of Supply Project*, December 18, 2024, Section 7.0, p. 98.

That approach may better preserve the distinction between traditional DSM resources and in this case, energy equity benefits. Finally, if the Board intends to use DSM budgets to reduce capacity costs and system peak risk during the winter, the evidence in this report supports redirecting DSM funds toward measures with clearer demand or flexibility benefits, such as effective peak demand reduction or DR programs, or SE measures that reduce overall energy bills while enabling more efficient use of the existing electric infrastructure.

On balance, standalone Solar PV should not be treated as a core DSM resource in Nova Scotia. Solar PV may reduce annual energy purchases, support clean energy objectives, and provide equity benefits for participating communities, but Nova Scotia is a winter-peaking system with growing peak demand, tightening planning reserve margins, and near-term resource adequacy concerns. In that context, DSM funds should be prioritized toward resources that reduce winter peak demand in a targeted manner, provide dispatchable demand response, improve flexibility, or otherwise reduce firm capacity requirements.

VII. Conclusion

We reviewed E1’s 2027–2031 DSM Plan based on E1’s application filing and supporting evidence, responses to information requests, and other evidence submitted in this proceeding. Our review focused on whether E1’s Preferred Plan reflects an appropriate allocation of DSM funding in light of Nova Scotia’s current affordability pressures, winter-peaking system needs, resource adequacy concerns, and the evolving role of demand-side resources in supporting the Province’s broader decarbonization goals. Specifically, we focus on the proposed spending levels as part of the overall DSM plan, the treatment of DR, SE, and Solar PV measures in the plan. Based on the evidence, we would like the Board to consider the following recommendations:

1. Affordability of the Plan

- Maintain discipline around total DSM spending, but do not treat a flat annual budget as sufficient evidence that the Plan is affordable or prudent.
- Reallocate funding away from increasingly expensive EE measures where they provide lower incremental value and direct a greater share of DSM funding toward resources that address Nova Scotia’s emerging system needs, including winter peak demand, resource adequacy, and flexible load.

- Require stronger benchmarking of E1's EE unit costs against comparable jurisdictions and programs and require E1 to explain why its lifetime efficiency costs appear materially higher than benchmarked costs in other jurisdictions and identify opportunities to reduce delivery costs.
- Use the 2027–2031 Plan period to transition DSM from a portfolio of customer rebate programs toward a resource planning tool aligned with system needs.

2. Treatment of Demand Response

- Treat DR as a valuable dispatchable system capacity resource, not merely as another customer-facing DSM program.
- Require E1 to expand and improve residential DR rather than pause new enrollment and wait for cost-effectiveness to improve.
- Prioritize near-term residential DR measures with strong winter peak reduction potential, particularly smart thermostats and domestic hot water direct load control and adopt best practices from successful programs such as Ontario's Peak Perks program.
- Continue scaling BNI DR where it is cost-effective, but do not allow BNI growth to substitute for a credible residential DR strategy.
- Require E1 to update its DR potential study, with emphasis on winter peak value, customer segments, event performance, attrition, device health, and locational value.
- Require annual DR performance reporting that includes verified peak reduction, event performance, opt-outs, attrition, device failures, customer compensation, delivery costs, and capacity accreditation.

3. Treatment of Strategic Electrification

- Require E1 to develop a phased SE pathway that identifies candidate measures with stronger cost-effectiveness potential, and do not allow SE to remain a research-only activity for the full 2027–2031 plan term.
- Require hourly modeling of SE impacts so that load-shape, peak impacts, and flexibility benefits are properly captured. Improve the data and methodologies used for SE cost-effectiveness analysis, including avoided costs, capacity values, and emissions accounting.
- Prioritize measures that avoid or reduce peak impacts, shift load to lower-cost hours, use passive or direct load control, and target areas of the distribution system with available capacity.

- Include transportation electrification in E1's SE phase-in work, particularly managed EV charging and evaluate managed EV charging as a resource that can mitigate distribution constraints, defer system investment, improve grid utilization, and enhance the cost-effectiveness of a broader electrification portfolio.
- Recognize that the modified PAC test creates a structural barrier for SE, and do not interpret failed modified-PAC results as proof that SE lacks value.

4. Treatment of Solar PV

- Remove standalone customer-sited Solar PV from DSM funding and avoid embedding standalone Solar PV in the DSM portfolio, if Board intends to prioritize the use of DSM funds for reducing winter peak demand and capacity costs.
- Recognize that Solar PV may provide annual energy, clean energy, equity, and community benefits, but does not provide meaningful winter peak capacity value in Nova Scotia absent storage or dispatchable controls.
- Treat the equity rationale for Mi'kmaw community Solar PV support separately from the DSM resource-planning rationale. Support targeted Solar PV for Mi'kmaw communities, if desired, through non-DSM funding mechanisms such as government programs, equity programs, community energy programs, distributed energy resource programs, or other clean-energy funding sources.
- If Solar PV remains under consideration as a DSM resource, require evidence of coincident winter peak reduction or pair it with dispatchable storage and controls that can provide measurable capacity value.
- Redirect DSM funds toward resources with clearer demand, flexibility, or capacity benefits, including effective Demand Response and strategic electrification measures designed to reduce overall energy bills while improving use of existing electric infrastructure.