

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: *The Public Utilities Act, R.S.N.S. 1989, c. 30* as amended

- and -

IN THE MATTER OF: An Application by EfficiencyOne for Approval of Supply Agreement for Electricity Efficiency and Conservation Activities between EfficiencyOne and Nova Scotia Power Inc., the establishment of a final agreement between the parties, and approval of a 2023 – 2025 Demand Side Management (“DSM”) Resource Plan

NOTICE OF APPLICATION

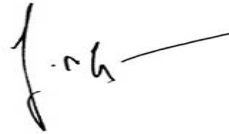
TO: The Nova Scotia Utility and Review Board (“UARB” or “the Board”)

1. EfficiencyOne is the holder of the Franchise issued by the Minister of Energy on November 28, 2014, effective January 1, 2015, to provide electricity efficiency and conservation activities to Nova Scotia Power Inc (“NS Power”).
2. Pursuant to section 79J of the *Public Utilities Act*, EfficiencyOne, as the franchise holder, is required to enter in an agreement for a term of three (3) years with NS Power for the supply of electricity efficiency and conservation activities (“Supply Agreement”), which agreement is subject to approval of the Board pursuant to section 79L of the *Public Utilities Act*.
3. There is currently in place a Supply Agreement between EfficiencyOne and NS Power for the years 2020 through 2022.
4. EfficiencyOne makes this Application to the Board, pursuant to the *Public Utilities Act* for the approval of a final Supply Agreement between EfficiencyOne and NS Power for a three year term for the calendar years 2023, 2024 and 2025, on such terms as the Board considers appropriate.
5. In support of this Application is filed the Evidence of EfficiencyOne, which includes Appendices containing additional materials supporting the Application.
6. On the Evidence filed in support of this Application, EfficiencyOne asserts that the Order sought by the Application is in the Public Interest.

7. EfficiencyOne therefore seeks an Order finalizing and approving a Supply Agreement between EfficiencyOne and NSPI, approving a 2023 – 2025 Demand Side Management resource plan, as submitted herein.

Dated this 11th day of March, 2022.

EFFICIENCYONE

A handwritten signature in black ink, appearing to read 'J. R. Gogan', with a long horizontal line extending to the right.

Per: James R. Gogan, EfficiencyOne Counsel

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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 2023-2025 Supply Agreement for Electricity Efficiency and Conservation Activities between EfficiencyOne and Nova Scotia Power Inc., the establishment of a final agreement between the parties, and approval of a 2023-2025 Demand Side Management (DSM) Resource Plan.

**Application of EfficiencyOne
as Holder of the
Efficiency Nova Scotia Franchise**

FILED
March 11, 2022

Evidence

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1. INTRODUCTION

Nova Scotia's energy and electricity future is at a decisive turning point as Nova Scotians face the global challenge of climate change. EfficiencyOne ("E1") has heard from Nova Scotians that climate change and the protection of our environment are significant concerns for them¹. This is echoed in the actions of the governments of both our Province and our Country as each has taken momentous and significant steps as part of a larger international initiative to reduce carbon emissions. In doing so, our Federal and Provincial governments are setting ambitious greenhouse gas reduction targets, expediting the timeframe for coal-fired plant retirements and enshrining these commitments in legislation.

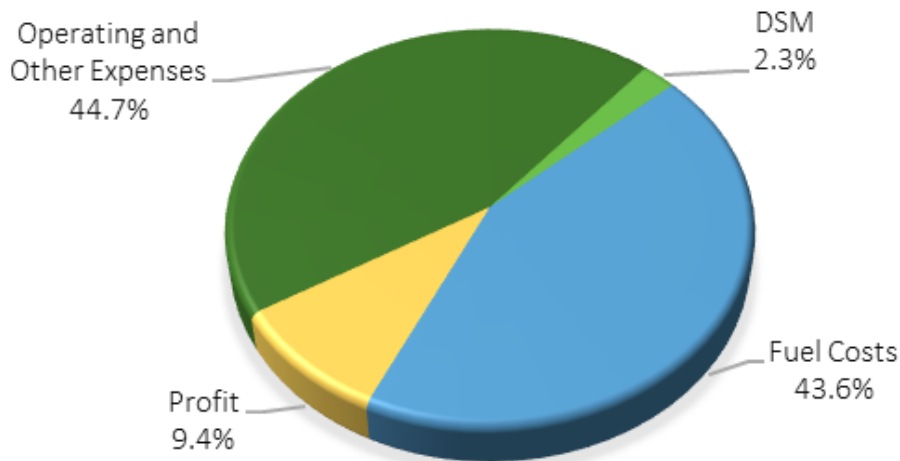
Energy efficiency will play a fundamental role in helping Nova Scotians reduce their energy consumption and ultimately spend less of their money on electricity while pursuing their environmental goals. E1 is positioned to lead the way in this effort. E1 has had success in not only meeting but exceeding energy efficiency targets, while keeping in step with the changing needs of customers and the transforming market. E1 is ready to deliver more savings.

While demand side management ("DSM") has generated consistent savings for Nova Scotia ratepayers, it is noteworthy to contextualize the actual annual investment expenditure against the amounts Nova Scotians pay for electricity each year as shown in Figure 1.

¹ Reference survey carried out by E1. Narrative Research 2021 DSM Report, Prepared for EfficiencyOne, January 2022.

- 1 Figure 1: In 2021, Nova Scotians Paid \$1.5 Billion for Electricity. Here's How That Money Was Used.

IN 2021, NOVA SCOTIANS PAID \$1.5 BILLION FOR ELECTRICITY.
HERE'S HOW THAT MONEY WAS USED:



Source: NS Power 2021 Audited Financial Statements

2
3 It is this historical success and commitment to deliver cost-effective energy efficiency to Nova Scotians
4 that form the foundation of E1's proposed 2023-2025 DSM Plan, which E1 has chosen to put forward as
5 its "Settlement Plan." The Settlement Plan builds upon E1's existing programs and services with the
6 enhancement of service offerings and the establishment of new initiatives aimed at pursuing increasingly
7 complex energy saving solutions and reaching diverse and underserved markets. E1 recognizes the
8 challenges faced by customers as they must look deeper for energy savings that will become more costly
9 and will continue to bring its expertise to help Nova Scotians find solutions to their energy efficiency
10 needs in a cost-effective and affordable way.

11
12 Nova Scotia Power's (NS Power) 2020 Integrated Resource Plan ("IRP") established a road map for Nova
13 Scotia's electricity needs for the next 25 years. The IRP is the key planning document upon which E1 relies
14 in its DSM planning. Since the development of the IRP, much has changed in Nova Scotia's electricity
15 landscape. The need to meet more aggressive environmental goals and emissions reductions than
16 anticipated by the IRP, including the earlier retirement of Nova Scotia's coal fired plants, means that E1
17 has to aggressively pursue alignment with the IRP to avoid lagging behind and being unable to achieve
18 future requirements. The Settlement Plan does just that while promising to deliver energy efficiency that

1 is affordable and in the best interest of electricity ratepayers in this Province. The Settlement Plan sets
2 Nova Scotia on a path toward realigning DSM spending at the appropriate level within three years while
3 also considering new climate change goals in Nova Scotia.

4
5 E1 developed its Settlement Plan over the course of a comprehensive and transparent stakeholder
6 engagement process, ensuring that all ratepayer classes were given the opportunity to participate and
7 provide meaningful input into various plan scenarios. Over the course of scenario development,
8 stakeholders were provided with initial model results and assumptions, technical tables, and rate and bill
9 impact analysis results, and given the opportunity to ask questions of and provide comments to E1.
10 Stakeholder input and advocacy were carefully considered and, where appropriate, incorporated by E1
11 into subsequent modelling rounds. The result of this extensive stakeholder engagement is a Settlement
12 Plan that will deliver cost-effective energy savings that are in the best interest of ratepayers and reflective
13 of stakeholders' feedback.

14
15 The Settlement Plan comprises diverse programming designed to meet the needs of each rate class
16 generally, with particular focus on reaching those who have a real need to benefit from reduced
17 electricity bills, such as low-income households and small businesses. The Settlement Plan will provide
18 relief from rising electricity rates and help customers reduce their electricity bills. E1 is prepared to
19 deliver, through the Settlement Plan, 412.7 GWh of energy savings and 96.7 MW of demand savings (78.8
20 MW from energy efficiency and 17.9 MW from demand response), with an investment of \$173.0M. With
21 an average payback period of under 5 years, Nova Scotians will enjoy the long-term savings benefits of
22 their investment for, on average, over 11 years.

23
24 Energy efficiency has been proven to be a sound investment. Now is the time for E1 to bring its expertise
25 and historic success in delivering energy efficiency savings to the forefront and continue to be a steady
26 and reliable steward in the navigation of Nova Scotia's rapidly evolving electricity and energy landscape.

27 28 1.1 APPROVAL OF SETTLEMENT PLAN

29 E1 requests approval by the Nova Scotia Utility and Review Board (the "Board" or "NSUARB") of its
30 Settlement Plan for the term 2023 through 2025 which is attached hereto as Appendix "A."

The Settlement Plan is the DSM Plan that will provide the best value to Nova Scotians by delivering cost-effective electricity efficiency and conservation activities at an affordable price and within a balanced portfolio over the 2023-2025 term. It represents a comprehensive suite of programs and service offerings which will:

- reduce electricity costs for customers;
- increase consumer awareness of cost-effective options for electricity consumption and/or consumption at peak periods;
- create favorable market conditions for the increased adoption of energy efficient and system-peak demand reduction equipment and upgrades; and
- aid in meeting stringent climate change initiatives undertaken by Canada and the Province of Nova Scotia.

The Settlement Plan will deliver approximately 412.7 GWh of affordable, incremental net energy savings and 96.7 MW (78.8 MW from energy efficiency and 17.9 MW from demand response) of cumulative system-peak demand savings to Nova Scotians. It builds on the historic success of energy efficiency programs and establishes new initiatives and enhanced service offerings, most notably aimed at historically underserved and low-income markets.

1.2 APPROVAL OF SUPPLY AGREEMENT WITH NS POWER

E1 requests the Board's approval of its form of Supply Agreement with NS Power. The operating terms and conditions of the Supply Agreement are substantially consistent with the Supply Agreements approved by the Board for the 2016-2018, 2019, and 2020-2022 DSM Plans.

1.3 STAKEHOLDER ENGAGEMENT

In an effort to attempt to bring consensus among stakeholders with respect to the appropriate level of DSM investment for 2023-2025, E1 adopted an earlier, more transparent and responsive level of stakeholder engagement in the development of its Settlement Plan. Planning began in March 2021 with initial stakeholder meetings and has continued through to the filing of this Application.

This included comprehensive development sessions through the Demand Side Management Advisory Group ("DSMAG"), enhanced by individual key stakeholder engagement. The engagement process

1 provided opportunities for stakeholders to inform the number of and parameters within the scenarios to
2 be assessed through modelling and to access modelling results and associated technical tables. This
3 enabled stakeholders to provide meaningful feedback and input through multiple rounds of modelling.
4 The intention was to ensure that the Settlement Plan presented for approval through the NSUARB
5 process represents a Plan that reflects stakeholder concerns, opportunities and goals.

6
7 In each round, feedback and input from stakeholders were considered and assessed and, in turn, used to
8 inform the next round of modelling. The process was intended to support the development of a
9 Settlement Plan which incorporated, to the extent deemed appropriate by E1, a broad range of
10 stakeholder perspectives with respect to energy, demand savings targets, and the current energy
11 landscape in Nova Scotia.

12
13 The process resulted in a general understanding among stakeholders of the evolving energy landscape in
14 Nova Scotia and a recognition that an increase in DSM is appropriate. The input of stakeholders in this
15 regard has been very helpful and directly informed the energy savings and investment levels established
16 in the Settlement Plan. It also helped focus attention on key programming opportunities such as the re-
17 introduction of a low-income whole home program component as well as attention to underserved
18 communities.

2. BACKGROUND

A brief review of the contextual factors aiding the development of the Settlement Plan is provided below.

2.1 PUBLIC UTILITIES ACT

E1 is the current holder of Nova Scotia's electricity efficiency and conservation franchise, making it a public utility in relation to franchise activities.

As the franchise holder, E1 has the exclusive right to supply NS Power with, "*reasonably available, cost-effective electricity efficiency and conservation activities.*" The *Public Utilities Act*, RSNS 1989, c. 380, ("*PUA*") requires that NS Power, "*undertake cost-effective electricity efficiency and conservation activities that are reasonably available in an effort to reduce costs for its customers.*"

The *PUA* requires E1 and NS Power to enter into an agreement describing the electricity and conservation activities that E1 will provide to NS Power over a term of three years. In the event that E1 and NS Power are unable to finalize an agreement, the *PUA* authorizes the Board to establish and finalize an agreement on terms it considers appropriate and in the best interests of NS Power's customers.

2.2 RECENT CLIMATE CHANGE ACTION

Considerable change has taken place since the approval of E1's 2020-2022 DSM Plan. Advancement in the efforts to combat global climate change has taken shape both provincially and federally. Aggressive decarbonization targets have been established and adopted by both the Province of Nova Scotia and the Government of Canada. Globally, many countries are either setting or considering setting the target of achieving carbon neutrality ("*net zero*") by the year 2050². These changes have impacted the 2023-2025 DSM planning landscape and will continue to shape the future of energy efficiency in Nova Scotia.

The Government of Canada has committed to achieving net zero emissions in its electricity sector by the year 2035³. Pursuant to the *Canadian Net-Zero Emissions Accountability Act S.C. 2021, c. 22*, Canada has

² United Nations, "Net-Zero Coalition", online: <https://www.un.org/en/climatechange/net-zero-coalition>.

³ Government of Canada, "Canada and the world move closer to powering past coal with more climate ambition at COP26" (November 4 2021), online: < <https://www.canada.ca/en/environment-climate-change/news/2021/11/canada-and-the-world-move-closer-to-powering-past-coal-with-more-climate-ambition-at-cop26.html>>.

1 committed to reducing greenhouse gas emissions by 40-45 percent by the year 2030 and achieving net
2 zero greenhouse gas emissions (GHG) by the year 2050⁴.

3
4 The Nova Scotia government has enacted the *Environmental Goals and Climate Change Reduction Act SNS*
5 *2021, c. 20*. This Act targets the reduction of greenhouse gas emissions by at least 53% below 2005 levels
6 by the year 2030 and echoes Canada's goal of achieving net zero emissions by 2050⁵. The Act recognizes
7 the role that energy efficiency will play in climate change mitigation and the reduction of greenhouse gas
8 emissions, by setting, supporting and strengthening energy efficiency programming⁶ as one of its goals.

9
10 E1 recognizes energy efficiency must play a key role in response to global climate change initiatives. In
11 September 2021, E1 published a white paper entitled, "*White Paper – 2050: Net-Zero Carbon Nova*
12 *Scotia*"⁷ which explored strategies available in Nova Scotia to achieve GHG emissions reductions.

13
14 E1 identified a number of commercially available technologies that can immediately contribute to the
15 reduction of carbon emissions. The priority for the next decade of decarbonization should be solutions
16 which rely on commercially available technologies which decline in cost when deployed at scale, such as
17 heat pumps, renewable electricity, and electric vehicles.

18
19 Increased investment in energy efficiency is necessary to support the achievement of emissions
20 reductions targets by the year 2030 at the lowest cost to ratepayers. The Settlement Plan incorporates
21 ratepayer benefits from energy efficiency related to the avoided costs of carbon.

22 23 2.3 STANDARDIZED FILING FRAMEWORK

24 This Application adopts the Standardized Filing Framework ("Framework"), intended to ensure consistent
25 content in DSM Plan filings, which was developed in consultation among E1, NS Power, and stakeholders,
26 and filed with the Board in a Consensus Agreement on 22 July 2016.

⁴ Government of Canada, "Canadian Net-Zero Emissions Accountability Act", online: <
<https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050/canadian-net-zero-emissions-accountability-act.html>>.

⁵ Environmental Goals and Climate Change Reduction Act, s.6.

⁶ *Ibid.*, s.7(b).

⁷ E1, "White Paper – 2050: Net-Zero Carbon Nova Scotia", (September 2021), online:
<https://www.efficiencyone.ca/impact/white-paper-2050-net-zero-carbon-nova-scotia/>.

1 The Framework outlines required content, including standard DSM information items, and requires E1 to
2 develop and file one or more alternate scenarios of DSM savings and budgets when bringing an
3 application for approval of its DSM Plan to the Board. It also establishes DSM standards, including overall
4 DSM planning and evaluation processes, and identifies objectives for pursuing DSM activities.

5
6 The Standardized Filing Framework directs that the Resource Plan identified in NS Power's Integrated
7 Resource Plan ("IRP") will serve to inform the development of a Preferred DSM Resource Plan by E1. E1's
8 Plan achieves this directive. However, as will be discussed further, E1 now questions the suitability of this
9 IRP scenario and the resultant avoided costs on the basis of recent legislative changes relating to
10 renewable energy standards, coal plant retirements and electrification.

11
12 The Standardized Filing Framework also provides that DSM Plans will balance multiple aspects of DSM for
13 the benefit of customers and establishes a "balanced plan approach" to guide the development of DSM
14 Plans.

15
16 The Settlement Plan is presented in accordance with the Standardized Filing Framework.

17 18 2.4 THE COVID-19 PANDEMIC

19 The global COVID-19 pandemic has challenged E1 in its administration of energy efficiency programming.
20 Restrictions in place due to the pandemic affected E1's ability to deliver services and implement certain
21 efficiency programs, especially those programs for which in-home and onsite visits were necessary
22 because of the nature of the services rendered. E1's supplier network was also impacted by pandemic
23 restrictions. As restrictions eased and with the establishment of public health directives for safe
24 operations, E1 has made, and continues to make, successful efforts to offset the effects of COVID-19.

25
26 E1 has been responsive to mitigating the effects of pandemic restrictions on its ability to achieve its
27 energy savings targets. While its mitigation efforts were successful, the COVID-19 pandemic has
28 nonetheless had an impact on other factors which ultimately come to bear on E1's ability to deliver its
29 services, including program participation, supply chains, industry capacity, and project timelines.

30
31 The pandemic challenged E1 to imagine and develop new and alternative service delivery approaches to
32 reach its participants. The lessons learned and alternative delivery options which have been adopted will

-
- 1 continue to play a role in E1's program administration and service delivery in the future. E1 is confident in
 - 2 the recovery it has experienced to date as it moves through the pandemic and that its supplier network,
 - 3 although impacted by the pandemic, is nevertheless intact.

3. SETTLEMENT DSM PLAN

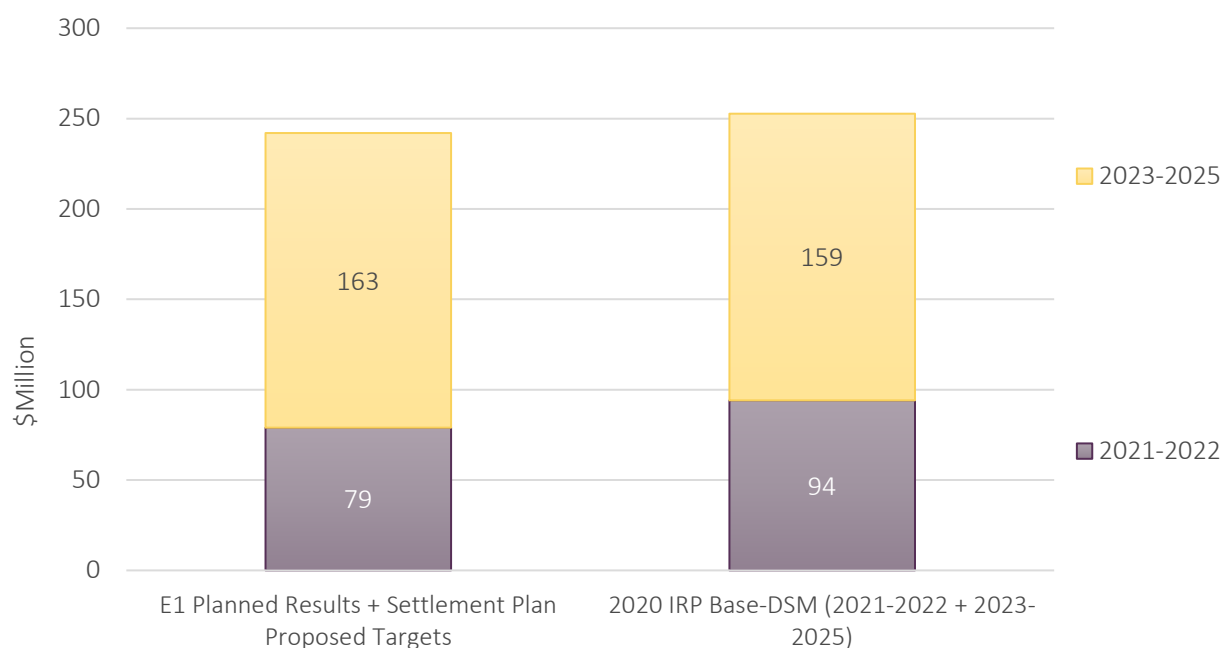
3.1 SUMMARY

The Settlement Plan represents a comprehensive suite of programs and service offerings which will deliver approximately 412.7 GWh of affordable, incremental net energy savings and 96.7 MW (78.8 MW from energy efficiency and 17.9 MW from demand response) of cumulative system-peak demand savings to Nova Scotians. These energy savings reflect approximately 1.2% of NS Power's load at generator. With past investments in DSM already providing Nova Scotia ratepayers with \$1.5 billion worth of lifetime savings in energy costs, the Settlement Plan builds upon past success and further increases the cumulative lifetime benefits for all rate classes.

The Settlement Plan has an average first year unit cost of \$0.39/kWh and a weighted average measure life of 11.3 years, resulting in a lifetime unit cost of \$0.035/kWh.

The Settlement Plan builds on the cumulative success of E1's energy efficiency programs and closely aligns with the 2020 IRP Reference Plan's aggregate DSM spending level which calls for a \$188.0 million investment in DSM between 2023 and 2025. The Settlement Plan proposes an investment of \$173.0 million across the three-year period which amounts to a cumulative spending level difference of \$15 million compared to the 2020 IRP Reference Plan. When examined over the five-year period ending in 2025, the Settlement Plan's DSM investment aligns with that of the IRP and results in an estimated incremental net energy savings of 649 GWh.

Figure 2: 2021-2025 Energy Efficiency Investment (Settlement Plan) compared to 2020 IRP Reference Plan



2021 tracked results and 2022 planned targets and spending were used for E1 Planned Results.

With a DSM investment of approximately \$58 million per year, the Settlement Plan will generate lifetime benefits for Nova Scotia ratepayers of \$543 million.

Table 1: 2023-2025 Settlement Plan

Year	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Weighted Average Measure Life (years)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
								incl. carbon	excl. carbon	incl. carbon	excl. carbon
2023	53.1	172.0	120.7	1,502	12.4	26.9	3.0	2.0	1.4	2.9	2.0
2024	57.5	179.0	142.6	1,540	10.8	25.6	10.0	2.0	1.4	2.8	2.0
2025	62.5	191.9	149.5	1,639	11.0	26.3	17.9	2.0	1.4	2.9	2.1
Total	173.0	542.8	412.7	4,681	11.3	78.8	17.9	2.0	1.4	2.9	2.0

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021. Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission, distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of benefits).

^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes only.

^dPAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. PAC excluding carbon is provided for informational purposes only.

The Settlement Plan offers ratepayers the opportunity to capture cost-effective energy savings at the level established by the IRP. The Settlement Plan will generate lifetime CO₂e savings of 1,742 kilotonnes (kt).

3.2 HIGHLIGHTS OF THE SETTLEMENT PLAN

Highlights of the 2023-2025 Settlement Plan include:

- Incremental annual energy savings that are equivalent to 1.2 percent of electricity generation
- Lifetime CO₂e reductions reaching 1,742 kt
- Weighted average measure life of 11.3 years
- Lifetime unit cost of \$0.035/kWh
- Lifetime benefits of \$543 million
- Pays for itself in under 5 years through avoided costs

4. BALANCED PLAN APPROACH

E1 has determined that 412.7 GWh in energy savings and 96.7 MW of demand savings (78.8 MW from energy efficiency and 17.9 MW from demand response) for 2023-2025 provide the best value to Nova Scotians. E1 has considered how to deliver this level of energy savings in a manner that best meets the needs of Nova Scotia ratepayers. Consistent with the direction of the Standardized Filing Framework, E1 has developed a Settlement Plan that follows a balanced portfolio design.

DSM portfolios must be responsive to evolving customer needs, technologies, market conditions and regulatory requirements. Portfolio design is critical to the effective, responsive, equitable and affordable delivery of the energy and demand savings in the Settlement Plan.

E1 has undertaken a balanced portfolio design that is aligned with the principles of the “Balanced Plan Approach” outlined in the Standardized Filing Framework. This Balanced Plan Approach directs E1 to *“produce DSM Resource Plans that balance multiple aspects of DSM for the benefit of customers.”*⁸

To achieve a balanced portfolio, E1 has applied the following design objectives:

- Low-income investment is 17-22% of the total energy efficiency investment. This aligns with 2016 Census data for low-income prevalence in Nova Scotia.
- 50/50% Residential-to-Business, Non-Profit & Institutional (“BNI”) investment split.
- 40/60% Residential-BNI energy savings split (informed by NS Power’s 2021 Load Forecast and E1’s 2019 DSM Potential Study).
- Increased investment in development and research specifically targeting innovation.
- Expansion of education and outreach for diverse and underserved communities.
- Increased diversity of energy and demand savings to further help customers achieve cost-effective energy solutions.
- Expanded accessibility for a wider variety of market sectors and customer segments.

⁸ M07543, 2016-2018 DSM Deferred Matters, Exhibit 3, Executed Revised Consensus Agreement, Appendix 1: Standardized Filing Framework, Section 4.3.1 Balanced Plan Approach, page 10, Filed July 22, 2016.

The application of these principles and objectives has resulted in some focused initiatives which are prominent in the Settlement Plan, including:

- Short- and long-term energy and capacity avoidance;
- Program delivery costs;
- Avoided energy and capacity investments;
- Non-electric qualitative benefits;
- Diversity of program delivery;
- Maintenance of business relationships and market presence; and
- Accessibility of programs by all market sectors and rate classes.

4.1 SHORT- AND LONG-TERM ENERGY AND CAPACITY AVOIDANCE

DSM investments provide value to ratepayers immediately (e.g. bill savings and avoided fuel costs) and over the long term (e.g. avoided investments in capacity and generation assets). Dunskey Energy Consulting⁹ described the balanced plan approach, and in particular short- and long-term energy and capacity avoidance, as follows:

“Short-term savings opportunities tend to revolve around the promotion of individual energy saving measures (e.g. lightbulbs, appliances) that can be implemented immediately (irrespective of how long they last). Short term success is critical to creating market familiarity, comfort, support for, and interest in efficient products and services. Long term savings opportunities tend to revolve around energy-saving practices and market conditions, such as education, training, financing, codes and standards, etc. – i.e. activities that may not translate into immediate savings but that ultimately transform markets to greater energy efficiency.”

The Settlement Plan achieves a balance of short- and long-term energy capacity avoidance.

4.2 PROGRAM DELIVERY COSTS

In the development of its Settlement Plan, E1 has taken into consideration cost-efficiencies and a full accounting of value to minimize the cost of delivering saved energy in the near-term and to maximize the

⁹ DSM Portfolio Design Principles and Considerations, Dunskey Energy Consulting, February 26, 2015. This Memorandum was previously filed with the Board as part of E1’s 2016-2018 DSM Resource Plan Application (M06733, Appendix F, page 2).

value of the savings delivered. E1 commits to controlling costs on an ongoing basis with the continuation of the cost management strategies referenced in the 2020-2022 DSM Plan. These include:

- Benchmarking – ensuring costs are aligned with other similar industries and organizations, as confirmed through market research and market comparisons prepared by third parties¹⁰.
- Competitive Procurement – following rigorous procurement practices to achieve best value by acquiring goods and services through a competitive approach.
- Independent Reviews – conducting third-party independent audits and reviews to ensure that the organization’s key controls are operating effectively and that the reporting of financial and energy savings results are accurate.
- Process Improvement – taking a strategic approach to process improvement with the implementation of an industry leading methodology to maximize cost effectiveness.

E1’s investment in customer incentives continues to be a significant category of spending as expected in a resource acquisition model. E1 has implemented an Incentive Setting Process which was an outcome of the CLEAResult study¹¹ conducted following the 2016-2018 DSM Plan. The incentive setting methodology is used when adding new measures or changing incentive levels on existing measures to confirm incentive levels fall within an acceptable range.

4.2.1 COST-EFFECTIVENESS TESTING FRAMEWORK

In Nova Scotia, the cost-effectiveness screening test for DSM is the Total Resource Cost (“TRC”) test at the program level. Cost-effectiveness testing is used to assess the relative value of DSM through a comparison of benefits and costs expressed as both the dollar value of the net benefit (or cost) and as a ratio of benefits to costs.

The TRC test compares the costs incurred to design and deliver programs and customers’ costs with avoided energy and other supply-side resource costs, including capacity, transmission, distribution and carbon. Each program set out in the Settlement Plan must achieve a benefit to cost ratio of at least 1 in order to pass the TRC test¹².

¹⁰ M09750, Exhibit 1, EfficiencyOne Performance Alignment Study, April 21, 2020.

¹¹ M07544, EfficiencyOne, Incentive Setting Methodology CLEAResult Report and EfficiencyOne Implementation Plan, Revised March 31, 2017.

¹² M03669, NSUARB Order and NSUARB Decision at para 82, June 30, 2011.

WHICH FACTORS HAVE CONTRIBUTED TO THE CONSERVATIVE COST-EFFECTIVENESS TEST RESULTS?

The TRC test results for the Settlement Plan are very conservative and understate the cost-effectiveness of the Settlement Plan. Factors which have contributed to the conservative TRC test results include:

- Understated avoided costs;
- No exceptions for low-income programming; and
- Application of both fixed and variable costs at all levels.

The cumulative effect of the above factors produces TRC test results which understate the cost-effectiveness of the programs in the Settlement Plan.

4.2.2 AVOIDED COSTS

E1 includes the avoided costs of energy, capacity, transmission, distribution, and carbon as benefits of energy efficiency in the TRC test, and capacity, transmission and distribution as benefits of demand response in the TRC test.

Avoided energy and capacity costs have been calculated by NS Power using the 2020 IRP Reference Plan 2.0C. The avoided costs of energy and the avoided costs of capacity are 30% and 41% lower, respectively, than in the 2014 IRP, which were used in the TRC test for the 2020-2022 DSM Plan. The avoided costs of carbon have been calculated by E1 by applying the Federal Carbon Pollution Pricing Benchmark to the emissions intensity for Base DSM savings, which was determined by comparing the 2020 IRP Reference Plan 2.0C emissions to the emissions from scenario 2.0C model run that did not include any new DSM.

As discussed further below, Scenario 3.1C would serve as the more appropriate proxy for determining the avoided costs associated with energy efficiency. Scenario 3.1C is more reflective of the legislated goals to retire coal plants and achieve a renewable energy standard of 80% by 2030, while also contemplating higher levels of electrification.

Use of Scenario 2.0C understates the benefits of energy efficiency and demand response resulting from the avoided costs and consequently negatively impacts the results of the cost effectiveness test screening.

4.2.3 LOW-INCOME PROGRAMMING

In order to increase equity and accessibility to low-income customers and ensure all Nova Scotians have the opportunity to realize the benefits of energy efficiency, E1 has expanded investment in programs targeting low-income customers. Such targeted programs are, however, more costly to deliver given there is minimal to no customer cost contribution in support of program delivery.

It is common practice to exempt low-income programs from the requirement of passing the TRC test in an effort to account for the additional costs associated with targeting low-income customers and non-energy benefits not accounted for in the test¹³.

Current practice in this province does not yet exempt E1's low-income program components from passing the TRC test. Low-income investment makes up 21% of the total investment proposed in the Settlement Plan. There are certain low-income program components which do not pass the TRC test. Including these program components in assessing the overall cost-effectiveness of the Settlement Plan negatively impacts the TRC test results of the Settlement Plan.

4.2.4 APPLICATION OF COSTS

A variety of costs are incurred in the acquisition of efficiency resources. It is important that these costs are included at the proper analytical level when analyzing the economics of efficiency resources for screening purposes. Only energy efficiency costs which are variable at a given analytical level should be included in the cost-effectiveness analysis, if screening decisions are being made at that level, as they are the only costs that can be avoided as a result of the analysis. Doing so could lead to rejections of investments whose marginal benefits exceed their marginal costs, thereby lowering net economic benefits.

E1's methodology for cost allocation undervalues the cost-effectiveness of the Settlement Plan at the measure level. E1 applies all costs, both fixed and variable, at all levels of testing including the measure level. Measure and program component level results are rolled up to program level results for screening purposes. In particular, E1 applies administrative costs at the measure level of testing, which is not in

¹³ Guidehouse Testimony. See also: <https://www.aceee.org/toolkit/2021/04/supporting-low-income-energy-efficiency-guide-utility-regulators>.

1 accordance with best practices if screening is to be performed at the measure level, as such allocations
2 may not be reflective of the cost to administer such measures. E1 applies costs in this way because the
3 screening level in Nova Scotia is at the program level, not the measure level.

4
5 This current practice is inconsistent if screening is to be performed at the measure level, with the
6 approach followed under the National Standard Practice Manual,¹⁴ which would remove certain non-
7 variable costs at the measure and program component level. For this reason, E1's measure and program
8 component level costs are overstated for the purposes of analyzing cost effectiveness testing (CET) ratios
9 at those analytical levels and result in decreased CET ratios.

11 WHY IS THE TRC TEST CONDUCTED AT THE PROGRAM LEVEL?

12 The Board has established that the TRC test be applied at the program level, rather than the measure
13 level, in accordance with industry best practices. Screening at the measure level is the most restrictive
14 application of the cost-effectiveness test and denies the DSM Administrator the opportunity to deliver a
15 portfolio of demand side management services that are accessible on an equitable and non-
16 discriminatory basis and responsive to the current market. Likewise, applying the TRC test at the measure
17 level prevents the DSM Administrator from proactively considering potential/future market development
18 and may reduce the overall net economic benefits of efficiency investments¹⁵.

19
20 Measures which fail the TRC test nevertheless provide strategic or long-term benefits, such as stimulating
21 demand for newer technologies to achieve economies of scale or increasing access to income-eligible
22 customers. Furthermore, measures which fail the TRC individually are combined into programs which
23 cumulatively are cost-effective.

24
25 For example, two components of the Existing Residential program, namely the Affordable Single-family
26 Homes and the Mi'kmaw Home Energy Efficient Project, do not pass the TRC test. However, the Existing
27 Residential program, as a whole, passes the cost-effectiveness screening. The inclusion of such
28 components in the program allows for greater participation in energy efficiency programming by
29 customers who have traditionally not had access to the energy savings achievable through DSM.

¹⁴ National Energy Screening Project, 2020. National Standard Practice Manual for Benefit Cost Analysis.

¹⁵ National Standard Practice Manual for Benefit Cost Analysis of Distributed Energy Resources, H.1.1.1.

E1 has the experience and expertise to develop a DSM Plan which ensures programs are cost-effective in the cumulative despite certain individual measures not passing the TRC. Deference should be given to E1 as the efficiency administrator in designing a DSM Plan which passes the TRC at the level established by the Board.

TRC RESULTS FOR THE SETTLEMENT PLAN

The Settlement Plan has an overall Benefit Cost Ratio (“BCR”) of 2.0 (2.0 for energy efficiency programs and 1.1 for demand response). All programs have a BCR greater than 1 and thus pass at the NSUARB approved level. Results of the TRC Test for the Settlement Plan are shown in Table 2 below. Results of the PAC Test are provided in Table 2 for informational purposes and represent the perspective of utility costs and benefits only.

Table 2: 2023-2025 Settlement Plan Cost-Effectiveness Results by Program

2023-2025 Settlement Plan	Total Resource Cost (TRC) Test ^a	Program Administrator Cost (PAC) Test ^b
Residential Energy Efficiency (EE) Programs		
Efficient Product Rebates	1.1	2.2
Existing Residential	1.5	2.4
New Residential	2.6	4.8
<i>Residential Low-Income</i>	<i>1.0</i>	<i>1.2</i>
Residential Sector Total	1.5	2.4
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs		
Efficient Product Rebates	3.7	7.5
Custom Incentives	2.5	4.3
Direct Installation	2.2	3.0
<i>BNI Low-Income</i>	<i>2.8</i>	<i>7.6</i>
BNI Sector Total	2.9	5.0
EE Portfolio Total (includes Enabling Strategies and EE Programs)	2.0	3.3
Demand Response (DR) Program		
DR Program Total	1.1	0.7

2023-2025 Settlement Plan	Total Resource Cost (TRC) Test ^a	Program Administrator Cost (PAC) Test ^b
Settlement Plan Total (EE + DR + ES)	2.0	2.9

Portfolio total cost-effectiveness tests are calculated using the sum of each year's present value of benefits and costs

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life.

4.3 AVOIDED ENERGY AND CAPACITY INVESTMENTS

DSM provides value to ratepayers by avoiding investments associated with supply side resources. In Nova Scotia, the following categories of avoided system costs are applied to DSM:

- Energy
- Capacity
- Transmission
- Distribution
- Carbon

Specific programs, program components, and measures will vary in how they impact energy savings and demand savings, and thus avoid investments in energy and capacity.

The Settlement Plan invests in energy and peak demand savings initiatives, as well as demand response which is a pilot initiative focused on reducing system coincident peak demand during times when its impact is most beneficial to the grid. Similar to previous DSM Plans, many measures included in the portfolio achieve both energy and peak demand savings. E1 recognizes that NS Power has experienced firm demand growth over the past number of years. Consistent with the outcome of the IRP, energy efficiency is a key mechanism to ensure that ratepayers benefit from the lowest cost solution to system design and operation.

The Settlement Plan invests in both energy and demand reduction initiatives, balancing the two priorities of avoiding energy and capacity investments. Building on the 2020-2022 DSM Plan, the Settlement Plan also includes demand reduction measures such as residential electric thermal storage units, three-element water heaters, and domestic water heater timers.

2023-2025 is the first time that demand response offerings will be included in an E1 DSM Plan. E1's 2019 DSM Potential Study included demand response and NS Power's 2020 IRP's Reference Plan included 75 MW of available capacity through demand response over the 2023-2025 DSM Plan period.

4.4 NON-ELECTRIC AND NON-ENERGY BENEFITS

DSM measures produce both non-electric and non-energy benefits and costs. Non-electric benefits impact customer fuel consumption from sources other than grid-supplied electricity. Non-energy benefits impact customer non-fuel costs that are affected by the installed measures (e.g. reduced maintenance).

The Settlement Plan modelling includes the additional customer cost of biomass for some measures that switch from electricity to biomass (e.g. wood stoves), as well as the customer cost savings from reduced water consumption for some measures (e.g. commercial dishwashers). The additional non-electric fuel cost and reduced water cost are considered in the TRC and PAC calculations. Consideration of the additional non-electric fuel cost is critical to avoid modelling results that unfairly favour fuel switching measures.

Throughout the 2023-2025 timeframe, E1 will continue to highlight non-energy benefits through its marketing and customer outreach efforts. In some instances, these are more effective drivers of participation than electricity cost savings alone.

4.5 DIVERSITY OF PROGRAM DELIVERY

Diversity in program delivery is a crucial way to minimize risk and involves the diversification of measures, markets and strategies.

The Settlement Plan includes a full suite of programs and strategies that seek to address a broad range of opportunities across all sectors. Despite some of the included opportunities presenting a higher unit cost, or a lower benefit/cost ratio, E1 has developed a diversified portfolio to account for risk from future world changes and to provide a broad program base to maximize equitable participation.

4.5.1 DIVERSE MEASURES

The Settlement Plan continues to diversify E1's measure mix. The Plan features 356 measures and 14 energy efficiency and 2 demand response program components. E1 continues to see decreased reliance

on savings from residential light-emitting diode (“LED”) lighting, and savings increase from other measures such as smart thermostats for residential baseboard heating and residential lighting controls.

4.5.2 DIVERSE MARKETS

The Settlement Plan also engages in a diverse range of markets. The investment in the Residential and BNI sectors is a 55/45% split in energy efficiency, with a focus of reducing barriers to reach a wide, diverse range of customers. The target markets include:

- Homeowners
- Renters and/or landlords
- Building owners
- Builders & developers
- Small business
- Industry
- Commercial
- Institutional

In response to stakeholder input, the Plan also focuses on increasing support for low-income customers. With an investment of 21%¹⁶ of the total Plan investment, support for low-income customers and underserved markets sees a 177% growth in funding from the 2020-2022 DSM Plan.

4.5.3 DIVERSE STRATEGIES

The Settlement Plan includes diverse strategies that focus on both market-driven programs (such as appliance retirement) and discretionary programs (such as Efficient Product Installation). The scenarios offer a range of delivery strategies inclusive of technical support (such as energy assessments and feasibility studies), point-of-sale and post-purchase rebates, direct installation, and self-serve participation channels. Through Enabling Strategies, efforts to research and develop an appropriate market transformation approach to support E1’s traditional resource acquisition model will be a key priority for 2023-2025.

¹⁶ The upward range is added to account for inflation and COVID-19 implications since 2016.

4.6 BUSINESS RELATIONSHIPS AND MAINTENANCE OF MARKET PRESENCE

Maintaining business relationships and market presence are key to minimizing risk and ensuring ratepayers get the best value for their investment. Creating stable conditions encourages suppliers and providers to enter the market, which creates economies of scale and encourages competition.

To provide predictability and consistency within Nova Scotia's market, E1's Settlement Plan maintains a roughly even investment in the Residential and BNI sectors. The Settlement Plan maintains E1's existing portfolio of programs inclusive of Business Development Managers, Onsite Energy Managers, and E1's Efficiency Preferred Partner ("EPP") network. This continued and consistent market presence builds on relationships with, among others, distributors, retailers, contractors, developers and consultants.

4.7 ACCESS TO PROGRAMS BY ALL MARKET SECTORS AND RATE CLASSES BY ADDRESSING BARRIERS TO PARTICIPATION

Equitable access to program benefits across all customer groups is a primary consideration in both program and plan design. In particular, unique barriers faced by low-income households, Mi'kmaw communities, rental housing and small businesses have been considered, despite the higher cost of savings this may imply. In response to stakeholder input and community engagement, the Settlement Plan builds on E1's existing portfolio of equitable programming, increasing access to energy efficiency programs and services as a result. Attachment 1 provides a breakdown of identified Residential and BNI barriers to participation in DSM programming and E1's strategies used to address these barriers in the Settlement Plan.

4.8 TRANSFORMATION OF THE NOVA SCOTIA MARKET

E1 is in an increasingly complex DSM planning environment as the Nova Scotia market matures and continues to experience increasing transformation, particularly in the residential sector. The residential lighting, heat pump, and new construction markets have achieved increasing energy efficiency transformation. To address current levels of market transformation and continue to encourage further transformation in the energy efficiency marketplace, the Settlement Plan reflects evolving opportunities through the re-introduction of residential behaviour and whole home low-income program components, further diversification beyond lighting measures through expansion of more complex retrofit projects,

-
- 1 and the development of a residential new construction market transformation program through its
 - 2 Enabling Strategies component.

5. AVOIDED COSTS

In calculating the benefits and cost effectiveness of the energy efficiency portfolio, E1 incorporated the avoided costs of energy, capacity, transmission, distribution and carbon. E1 used the avoided costs of capacity and energy calculated by NS Power using their most recent IRP (specifically the 2020 IRP Reference Plan 2.0C). The avoided costs of transmission and distribution were provided by NS Power via a separate filing and utilize a methodology based on historical transmission and distribution investments. The avoided costs of carbon are calculated by E1 through the application of the federal trajectory pricing¹⁷ to an emissions intensity for Base DSM savings, calculated based on the NS Power system using the 2020 IRP Reference Plan 2.0C results, using a similar method to what NS Power used to calculate avoided energy and capacity costs.

In developing the Settlement Plan, E1 considered the impacts the *Environmental Goals and Climate Change Reduction Act* would reasonably have on the 2020 IRP Reference Plan as it relates to the level of DSM as well as avoided costs. E1 maintains that an alternate Reference Plan reflective of these legislative changes is appropriate. As detailed in his evidence, provided as Appendix D, David Hill¹⁸ indicates that Scenario 3.1C would likely result in material changes to both the level of energy savings due to DSM and the avoided costs of energy and capacity.

It is E1's position that the 2020 IRP Reference Scenario 3.1C is more suitable for assessing the affordability of the Settlement Plan given its alignment with the timeline for coal plant retirement, the *Environmental Goals and Climate Change Reduction Act* and the renewable energy standard. Its assumption of an electrification implementation that is more responsive to mandatory requirements is further support for its suitability.

The impact of these environmental requirements on the selected IRP Resource Plan was raised before this Board in NS Power's Application for approval of the Smart Grid Solar Garden Rate Rider¹⁹. Both Synapse and Resource Insight submitted that the credit component of the rider did not sufficiently account for the avoided environmental compliance costs. Synapse suggested that the credit provided to

¹⁷ Environment and Climate Change Canada. A Healthy Environment and A Healthy Economy, 2020.

¹⁸ 2023-2025 DSM Plan Resource Application, Appendix C

¹⁹ M10176

1 subscribers of the solar garden was based on the avoided costs from an IRP scenario (Scenario 2.0C) that
2 is inconsistent with recent policy pronouncements. Further, the avoided cost calculations do not include
3 avoided environmental compliance costs associated with the implementation of a Renewable Energy
4 Standard of 80 percent. The Board stated in its findings²⁰:

5
6 [25] The issue of environmental avoidance costs, including for energy utilities like NS Power, is a
7 very fluid topic. There have been significant developments even since the filing of this application
8 in late June 2021. On October 27, 2021, the Provincial Government introduced Bill no. 57 in the
9 Legislature, entitled the *Environmental Goals and Climate Change Reduction Act*. This Bill set out
10 targets and goals for climate change mitigation and adaptation and the reduction of greenhouse
11 gas emissions ...

12
13 [26] Moreover, the Federal Government is anticipated to soon release revised requirements for
14 reduced GHG emissions and carbon levels, including new Clean Fuel Standards. As this decision is
15 being written, global leaders are attending the COP26 Climate Summit in Glasgow, Scotland.

16
17 [27] Further, in recent months, NS Power itself has publicly announced that it is actively working
18 with the Provincial and Federal Governments and other governments and utilities in the region to
19 develop the Atlantic Loop and strengthen the regional integration of the grid to address
20 anticipated environmental requirements.

21
22 [28] Taking into account all of the above, the Board accepts the evidence of Synapse and
23 Resource Insight that the SG Rider credit may understate the net value of solar energy from the
24 solar garden to the grid.

25
26 At the time of filing, NS Power has not yet provided updated avoided costs of energy and capacity taking
27 into account environmental legislation and directives.

²⁰ M10176, NSUARB Decision, November 10, 2021.

A Reference Plan which is not aligned with the current energy landscape has significant impacts on the evaluation of benefits derived from energy efficiency and demand response. Inaccurate and understated avoided costs have the potential to materially impact the development of E1's DSM Plan by creating:

- An understatement of lifetime benefits;
- An impact on portfolio design;
- Understatement of cost effectiveness screening; and
- An inaccurate rate and bill impact analysis.

The 2020 IRP – “Powering a Green Nova Scotia, Together” contemplates an evergreen process as conditions change²¹. Specifically, at s. 1.9.2, #8 NS Power states:

Continuously refine the Action Plan and the Roadmap items via an evergreen IRP process. This process should facilitate annual updates as conditions change and technology or market options develop, and as Action Plan items are completed or significantly advanced. Nova Scotia Power will include a summary of updates as part of IRP Action Plan reporting and will incorporate the opportunity for stakeholder comment and feedback as part of the update process.

Accordingly, it is anticipated that NS Power will update the 2020 IRP in response to recently legislated climate change reduction goals. However, in the development of its 2023-2025 DSM Plan, E1 was required to employ the current 2020 IRP and Reference Scenario 2.0C.

E1 maintains that the use of avoided costs developed from Scenario 2.0C does not properly reflect Nova Scotia's energy landscape and results in an understatement of benefits accruing to ratepayers under the Settlement Plan. Consequently, their use in any DSM analysis minimizes the expected financial benefits of DSM investments between 2023 and 2025. Forecasts which employ the IRP's current avoided costs will generate expected DSM economic benefits that are conservative when, in fact, the actual DSM benefits are likely significantly greater.

Table 3 provides a complete list of avoided costs used in assessing the Settlement Plan. Additional detail on the avoided costs used by E1 in the 2023-2025 DSM Plan is provided in Attachment 2 to Appendix A.

²¹2020 IRP, s. 1.9.2, page 29

1 Table 3: Avoided Costs Used in Assessing the Settlement Plan

Item	Description of Avoided Costs
Avoided Costs of Energy	• DSM Plan & RBIA: Avoided costs of energy were based on NS Power's 2020 IRP Reference Plan (scenario 2.0C) for energy efficiency. Demand response is assumed to have no energy impacts, and therefore, avoided cost of energy is negated (i.e. zero).
Avoided Costs of Capacity	• DSM Plan & RBIA: Avoided costs of capacity were based on NS Power's 2020 IRP Reference Plan (scenario 2.0C) for energy efficiency and demand response.
Avoided Costs of Transmission and Distribution	• DSM Plan & RBIA: Transmission and distribution avoided costs were as developed by NS Power and the DSMAG in 2020, with remaining issues addressed in 2021. E1 is using the system wide costs.
Avoided Costs of Carbon	• DSM Plan & RBIA: Avoided cost of carbon was developed using the Federal Policy Position Document, inclusive of the federal backstop trajectory (\$170 per tonne by 2030, and escalating by 2% annual inflation beyond 2030). This price of carbon (\$/tonne) is multiplied by NS Power's emissions intensity for Base DSM savings (tonne/MWh), established using the Difference in Carbon Emissions (DICE) method for the 2020 IRP Reference Plan (scenario 2.0C), to results in a \$/MWh avoided cost of carbon. Demand response is assumed to have no energy impacts, and therefore, avoided cost of carbon is negated (i.e. zero).

6. DETERMINING THE APPROPRIATE LEVEL OF ENERGY SAVINGS

The Settlement Plan results in energy savings of 120.7 GWh in 2023, ramping up to 149.5 GWh in 2025. This level of energy savings was determined based on the following factors:

- 2020 Integrated Resource Plan;
- Stakeholder consultation;
- Industry capacity;
- Industry trends;
- The *Environmental Goals and Climate Change Reduction Act*; and
- Market transformation.

6.1 THE 2020 INTEGRATED RESOURCE PLAN

Integrated resource plans are employed as foundational instruments to shape system planning and operations, which informs such decisions as optimal supply alternatives including DSM. The IRP is intended to identify the utility's lowest revenue option over a 25-year planning horizon. NS Power's current IRP and the selected Reference Plan are essential inputs to the DSM Plan.

NS Power's most recent IRP was developed in 2020 through an extensive stakeholder process. The outputs of the IRP, including Reference Plan 2.0C, are important indicators of the appropriate DSM investment level and reflect the best interests of the ratepayers (subject to concerns about 2.0C being the most appropriate Reference Plan).

6.1.1 THE ROLE OF THE IRP IN ESTABLISHING THE APPROPRIATE LEVEL OF DSM ENERGY SAVINGS

NS Power modelled various reference scenarios in the development of the IRP and selected Reference Plan 2.0C as the scenario which will deliver the lowest net revenue requirements to the NS Power electricity system.

Historically, E1 has relied on the IRP in the development of its energy savings targets and avoided costs and maintains that it is appropriate to do so. The Settlement Plan incorporates the energy and capacity avoided costs of Reference Plan 2.0C.

1 In the relatively short time frame between the development of the 2020 IRP and the development of the
2 2023-2025 DSM Plan, aggressive climate action initiatives were introduced by federal and provincial
3 governments²². The introduction of these initiatives impacts the IRP Reference Plan. This includes the
4 calculated values of avoided costs of energy and capacity. In addition, in December 2020, the Federal
5 Government announced its intention to provide longer term certainty on the price of carbon pollution
6 out to 2030 through the Federal Carbon Pollution Pricing Benchmarking. The Government initially
7 proposed a 2023 price of \$65 per tonne rising to \$170 per tonne by 2030. Commencing in 2023, Nova
8 Scotia must establish a CO₂ emissions pricing system utilizing one of the following two options:

- 9 1. Explicit price-based system; or
- 10 2. Cap-and-trade system.

11
12 Regardless of the option chosen, the system must meet the benchmark criteria and assessment process
13 established by the Federal Government²³. The system proposed by Nova Scotia may not be publicly
14 known during the timeframe of this proceeding, and approval by the Federal Government is not expected
15 until late 2022. Notwithstanding this uncertainty, what is clear is there will be carbon pricing in existence
16 in Nova Scotia in 2023 and this system will comply with the Federal emissions standards and criteria.

17
18 To realize the results of the IRP Reference Plan an investment of \$1.35 billion is required over the 25-year
19 planning horizon from 2021 through 2045 to deliver 2,896 GWh of energy savings. Over the 2023-2025
20 planning period the IRP Reference Plan proposes a cumulative DSM investment level of \$188 million
21 versus \$173 million under E1's Settlement Plan. IRP Reference Plan 2.0C represents a scenario of low
22 electrification and coal plant retirement by 2040 together with Base-DSM. The forward-looking level of
23 low electrification and the planned 2040 coal plant retirements under IRP Reference Plan 2.0C are no
24 longer in line with legislative goals and initiatives. To be clear, E1 has followed the IRP Reference Plan in
25 developing its Settlement Plan, however, it would be irresponsible not to consider changes in the energy
26 landscape and legislation that are not reflected in IRP Reference Plan 2.0C.

27
28 The Settlement Plan is reflective of these changes in the energy landscape by proposing a ramping up of
29 investment over the Plan period and a continuing upward trajectory while at the same time remaining

²² Supra note 4 and 5

²³ Update to the Pan Canadian Approach to Carbon Pollution Pricing 2023-2030

1 within the IRP Reference Plan cumulative investment levels for the 2023-2025 period. In accordance with
2 the 2020 IRP, by the end of 2025, 633 GWh of energy savings are required. The adoption of the
3 Settlement Plan provides an opportunity to recapture lost savings associated with previous
4 underinvestment and positions ratepayers along a trajectory to achieve energy efficiency savings in a
5 manner that is consistent with 2020 IRP results.

6
7 As elaborated in the sections that follow, recent changes to the Nova Scotia energy landscape and
8 environmental legislation signal that the avoided costs of the IRP are now understated. This, in turn,
9 supports E1's position that the quantified benefits of the Settlement Plan are conservative values, and the
10 future benefits are, in fact, even greater.

11 12 6.2 IMPACT OF THE ENVIRONMENTAL GOALS AND CLIMATE CHANGE 13 REDUCTION ACT AND OTHER CLIMATE CHANGE GOALS ON THE IRP 14 REFERENCE PLAN RESULTS

15 6.2.1 THE ROLE OF DSM IN THE CLIMATE CHANGE EMERGENCY

16 NS Power's 2020 IRP reflected themes of decarbonization, with all scenarios adhering to the Province of
17 Nova Scotia's *Sustainable Development and Goals Act* emissions targets, as well as regional integration
18 and electrification. Demand side resource options were explored in the 2020 IRP through the
19 incorporation of E1's 2019 DSM Potential Study. The 2020 IRP Results include Base-DSM and Base-DR in
20 the IRP Reference Plan. The selected IRP Reference Plan is the scenario that results in the lowest net
21 present value revenue requirement for ratepayers.

22
23 However, following the IRP, and while E1 was developing the Settlement Plan, the Province of Nova
24 Scotia enacted the *Environmental Goals and Climate Change Reduction Act*, which legislates the goal of
25 phasing out coal-fired electricity by 2030. This legislation, together with previous amendments to *Nova
26 Scotia's Renewable Electricity Regulations*, will now require NS Power to deliver 80% renewable energy to
27 customers by 2030. The phasing out of coal-fired generation was accelerated by 10 years, and NS Power's
28 window to achieve this milestone has been curtailed from 18 to 8 years as of 2022. E1 maintains the
29 requirement to meet significantly more aggressive environmental goals comes to bear on the
30 appropriateness of the selected Reference Plan in what is now a very rapidly transforming planning
31 landscape.

1 The role of DSM will become more vital to Nova Scotians with the introduction of ambitious provincial
2 climate change and emissions reductions goals. An increase in the level of DSM now in a manner that still
3 embraces the lowest net revenue option of the IRP is required under this Plan. With such an approach in
4 place, the Settlement Plan will position Nova Scotians along a path to realizing the full cost-savings
5 achievable through energy efficiency programming and meeting these important emissions reductions
6 goals.

7
8 E1 has the expertise in implementing energy efficiency programs and a track record of contributing to the
9 reduction of greenhouse gas emissions in Nova Scotia. As a result of DSM delivered over 2011-2021,
10 annual CO₂e emissions from the electricity sector have been reduced by approximately 884 kt.

7. DETERMINING THE APPROPRIATE INVESTMENT LEVEL

7.1 AFFORDABILITY

Affordability is a critical factor in DSM planning. In its decision on the 2016-2018 DSM Plan, the Board stated it is, “specifically directed by the 2014 amendments to the PUA to address the issue of affordability.”²⁴ The legislation does not define affordability, nor does it define the parameters for the Board’s consideration; determining whether a DSM Plan is affordable is left to the discretion of the Board in its inquiry and assessment of the evidence presented to it.

In considering the overall affordability of the Settlement Plan, E1 examines and expands on the following considerations within this section:

- The best interests of ratepayers;
- Short- and long-term affordability of the Settlement Plan;
- The Settlement Plan’s alignment with the 2020 IRP’s investment targets and affordability objectives;
- The Settlement Plan’s payback timeframes from both a Portfolio and Rate Class perspective;
- The need for DSM investment to eclipse a minimum utility revenue percentage;
- Scan of leading jurisdictions;
- The RBIA of the Settlement Plan; and
- The Settlement Plan as a low risk, least cost option available to ratepayers.

7.1.1 THE BEST INTERESTS OF THE RATEPAYER

THE BEST INTERESTS OF RATEPAYERS INCLUDES BOTH SHORT- AND LONG-TERM AFFORDABILITY

A Settlement Plan that balances short- and long-term affordability is in the best interests of ratepayers. While short-term affordability is often emphasized, the NSUARB has stressed the importance of balancing short-term and long-term considerations. In accordance with subsections 79L(8) and 79L(9) of the *Public*

²⁴ M06733, NSUARB Decision, August 12, 2015, para 76.

1 *Utilities Act*, affordability for ratepayers must be considered when assessing E1's DSM Application²⁵. As
2 stated by the Board in its decision on the 2016-2018 DSM Plan, at paragraph 82:

3
4 The Board does not believe that ratepayers are well-served, or that it is in their best interests to
5 focus only on short term costs and thereby deny customers the real long term cost savings that
6 are possible from a balanced and properly implemented DSM program. Accordingly, while the
7 Board finds that there has been a change in focus mandated by the Legislature, and an increased
8 emphasis on short term rate impacts, the overarching consideration continues to be "*the best*
9 *interests of Nova Scotia Power Incorporated's customers*" as stated in Section 79L (8) of the PUA.
10 [Emphasis Added]

12 BALANCING SHORT- AND LONG-TERM AFFORDABILITY

13 The Settlement Plan seeks to maximize value for ratepayers by balancing short- and long-term
14 affordability. This is accomplished through a DSM Plan that incorporates the needs and best interests of
15 ratepayers, the IRP, legislative changes, and targets, and forward-looking RBIA results, and cost-
16 effectiveness testing results.

17
18 DSM, and particularly its energy efficiency programs, is demonstrably lower in price than the fuel option it
19 displaces, making it a logical and affordable first choice investment for ratepayers. Based on the cost of
20 fuel as reported in NS Power's 2021 financial statements of \$0.075/kWh, the cost of DSM at \$0.035/kWh
21 is less than the average cost of fuel by \$0.039/kWh. This results in lifetime fuel savings of approximately
22 \$187 million²⁶ assuming fuel costs remain consistent with 2021 levels. Since 2015, the cost of fuel in
23 \$/kWh has ranged from 129% to 219% higher than the cost of DSM per kWh, and in the last three years
24 that value has increased to an average of 210% (Table 4). The ability to avoid fuel costs through the use of
25 a more cost-effective DSM alternative is always in the ratepayers' best interests, even in the short-term.
26 These benefits are then amplified in the long-term. In lowering overall fuel costs for the utility, DSM

²⁵ Section 79L(8), PUA: The Board shall approve an agreement pursuant to this Section if, in addition to any other matters considered appropriate by the Board, it is satisfied that the agreement, including the proposed electricity efficiency and conservation activities that are the subject of the agreement, is in the best interests of Nova Scotia Power Incorporated's customers and satisfies the requirements of Section 79J. (9) The Board's assessment of the proposed electricity efficiency and conservation activities for the purpose of the approval must take into account their affordability to Nova Scotia Power Incorporated's customers, along with any other matters considered appropriate by the Board or as may be prescribed. 2014, c. 5, s. 15

²⁶ Lifetime fuel savings that result from the 2023-2025 DSM Plan.

applies a downward pressure on the fuel adjustment mechanism (FAM), which, in turn, benefits all ratepayers.

Table 4: Cost Difference of DSM and Fuel

Year	Cost Difference of DSM & Fuel	
	(Difference \$ per kWh)	(Difference as a % of DSM cost)
2015	0.031	171%
2016	0.029	183%
2017	0.024	129%
2018	0.037	196%
2019	0.040	212%
2020	0.046	219%
2021	0.052	226%

The Settlement Plan provides a cumulative \$543 million worth of lifetime benefits in the form of avoided costs to ratepayers at a cost of \$173 million. The Settlement Plan is designed to achieve 4,681 GWh of cumulative net lifetime energy savings.

The Settlement Plan reflects increased investments in DSM that provide ratepayers the ability to achieve the IRP levels that are in their best interest by 2025.

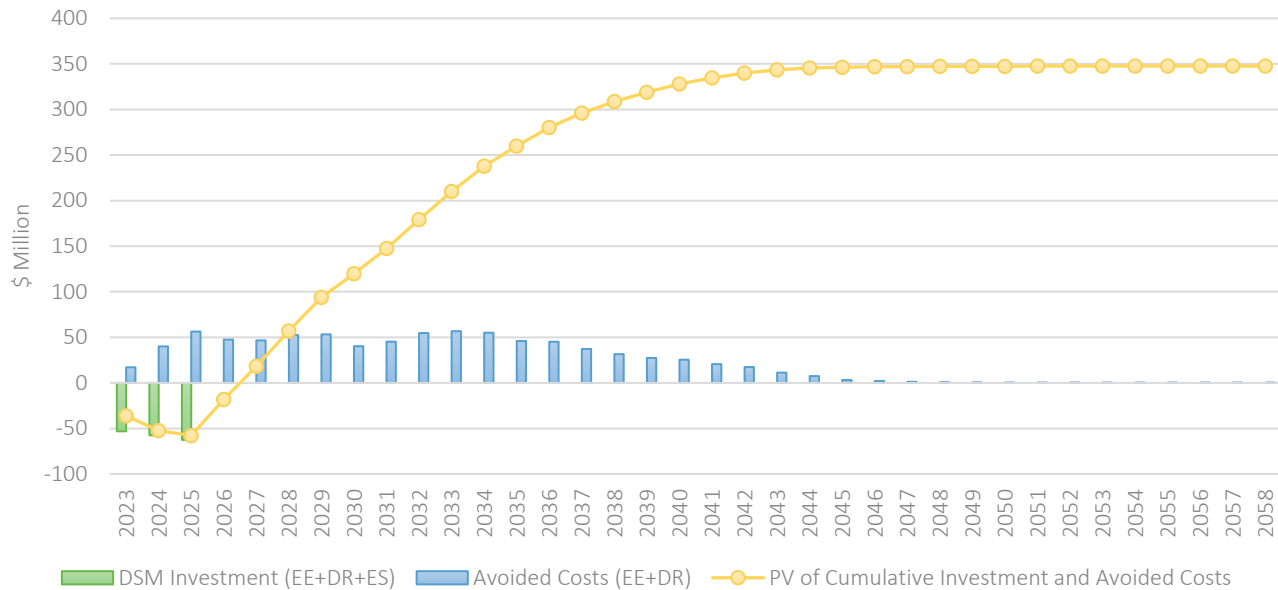
PAYBACK PERIODS ARE REASONABLE

DSM is a long-term investment with lasting benefits and considerable lifetime savings, yet the Settlement Plan also contributes to short-term and immediate ratepayer benefits. In the short-term, the Settlement Plan will achieve 412.7 GWh of incremental cumulative net energy savings by 2025. Over the same time period in which the investment of \$173 million is made, the Settlement Plan will achieve \$114 million in avoided utility costs. By the end of 2027, the investment will be fully “paid back” in the sense that the cumulative value of avoided costs will eclipse the investment amount. For any single rate class, this payback will occur no later than 2029.²⁷ A short payback period that provides fully funded DSM benefits no later than the end of 2029 is in the best interests of ratepayers as it leverages the lower costs

²⁷ Reference the Schedule re Payback Periods, average and individual alike.

associated with present-day investment prices and mitigates the long-term effects of inflation and rising costs – as illustrated Figure 3.

Figure 3: Payback Analysis – Settlement Plan



DSM investment includes EE, DR, and Enabling Strategies. For DR, investment includes only the E1 portion of costs and benefits. Green bars are nominal investment. Blue bars are nominal avoided cost. Yellow line is a 2023 present value (PV) calculated using NS Power's Weighted Average Cost of Capital (WACC).

7.2 JURISDICTIONAL SCANS

The Settlement Plan considered both utility-specific and statewide data made available in *The 2020 Utility Energy Efficiency Scorecard* and *The 2020 State Energy Efficiency Scorecard*, respectively. In doing so, it is clear that the Settlement Plan proposes an investment in DSM, and specifically energy efficiency, that is very reasonable relative to NS Power revenues and sales and a positive step toward reaching the investment levels seen in other jurisdictions.

7.3 DSM INVESTMENT SHOULD ECLIPSE A MINIMUM LEVEL OF NET INCREMENTAL SAVINGS AS A PERCENTAGE OF THE UTILITY'S RETAIL SALES

Historically, E1 has used a metric of percentage of energy savings to electricity sales and/or load. As will be discussed further, despite a proven track record of affordability, Nova Scotia continues to lag leading jurisdictions in this metric.

Table 5: Board-Approved Energy Savings as a Percentage of NS Power's Electricity Generation (2021 NS Power Load Forecast)

Year	Board-Approved GWh	% of Electricity Load
2015	121.1	1.1
2016	133.1	1.2
2017	136.5	1.3
2018	136.3	1.2
2019	127.2	1.1
2020	119.2	1.1
2021	121.5	1.1
2022	127.1	1.2

Nova Scotia has remained stagnant at or near the 1.1% metric over the last Plan period. As a consequence, Nova Scotia ratepayers have not captured the cost-effective energy efficiency opportunities available. The Settlement Plan proposes a modest directional move toward leading jurisdiction levels at 1.2% of electricity load. This is an appropriate and cost-effective move in addressing a widening gap.

The 2020 Utility Energy Efficiency Scorecard ranked the 52 largest electric utilities in the United States on utility-sector energy efficiency programs for 2018²⁸. Under the Settlement Plan's energy efficiency portfolio, a savings that equates to 1.2% of load, or 412.7 GWh, is proposed. The Scorecard indicates a net savings range of 0.01 to 3.73% of retail sales²⁹.

The 2020 State Energy Efficiency Scorecard offers similar performance and target data, but on a state-by-state basis for 2019 using incremental savings data from 2019 and the prior year's retail sales³⁰. The states of Massachusetts, Vermont, and Maine are the most direct comparisons to Nova Scotia on the basis of climate, heating and cooling cycles and fuel sources. Incremental net savings in 2019 and net savings as a percentage of 2018 retail sales were as follows for each State:

- Massachusetts: 1,199,409 MWh, 2.25%;

²⁸ 2020 Utility Energy Efficiency Scorecard https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf

²⁹ 2020 Utility Energy Efficiency Scorecard

³⁰ The 2020 State Energy Efficiency Scorecard, <https://www.aceee.org/sites/default/files/pdfs/u2011.pdf>

- Vermont: 117,289 MWh, 2.12%; and
- Maine: 127,786 MWh, 1.03%.

These most comparable jurisdictions represent an average DSM savings as a percentage of retail sales of 1.8%. This indicates the Settlement Plan is generally aligned with approaches among comparable American utilities in terms of net savings targets. The Settlement Plan's proposed 1.2% represents a conservative approach to DSM savings.

7.4 DSM SPENDING SHOULD ECLIPSE A MINIMUM PERCENTAGE OF UTILITY REVENUE

This 2020 Utility Energy Efficiency Scorecard also provides data pertaining to the amount of energy efficiency spending relative to a given utility's total revenue³¹. In doing so, it generates an average allocation figure that serves as a meaningful comparator for the Settlement Plan's proposed targets³². As stated by the American Council for an Energy-Efficient Economy (ACEEE), "*spending on energy efficiency programs ... is a critical indicator of a utility's commitment to energy efficiency.*"³³ [Emphasis added]

Results from the 2020 Utility Energy Efficiency Scorecard indicate that the largest utilities in the United States spent, on average, 2.58% of their 2018 revenue on Energy Efficiency programs with spending ranging from 0.04 to 11.38% among those utilities.

On a state-by-state basis for 2019, the following was noted for Massachusetts, Vermont, and Maine in terms of electric efficiency spending in 2019 and the percentage of 2018 statewide electric revenue spent toward said programming³⁴:

- Massachusetts: \$620.4 Million, 6.29%;
- Vermont: \$55.2 Million, 6.59%; and
- Maine: \$45.9 Million, 2.76%.

³¹ The 2020 Utility Energy Efficiency Scorecard, https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf

³² The 2020 Utility Energy Efficiency Scorecard, https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf

³³ The 2020 Utility Energy Efficiency Scorecard, https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf

³⁴ <https://www.aceee.org/sites/default/files/pdfs/u2011.pdf>

1 Once again, the States of Massachusetts, Vermont, and Maine serve as suitable comparator jurisdictions
2 in assessing energy efficiency program spending as a percentage of revenue. The DSM spending levels
3 above equate to an average of 5.21% of total revenue. Notwithstanding the proposed increase under the
4 Settlement Plan, Nova Scotia remains below leading comparable American jurisdictions in terms of
5 energy efficiency investment as a percentage of revenue.

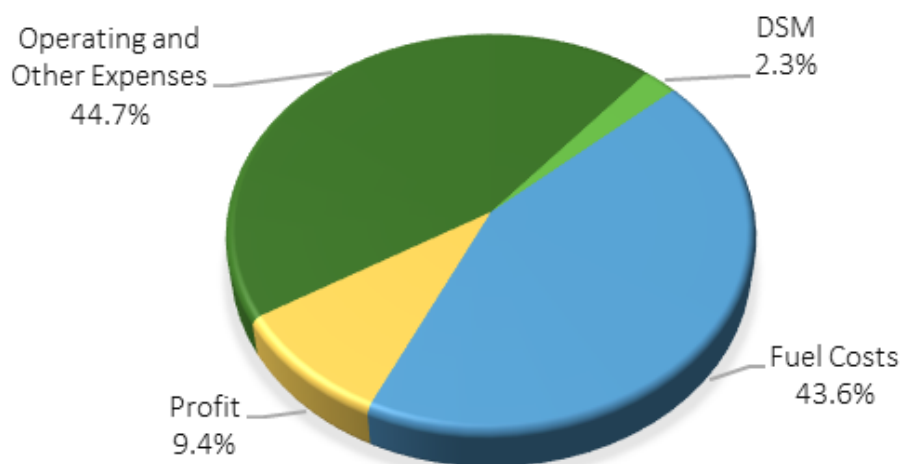
7 7.5 DSM IN NOVA SCOTIA TRAILS INVESTMENT LEVELS OF LEADING 8 AMERICAN JURISDICTIONS AS A PERCENTAGE OF REVENUE

9 In 2020, Nova Scotia ratepayers spent approximately \$1.5 billion on electricity. However, in contrast to
10 leading American jurisdictions, in 2020 less than 2% of ratepayers' money was spent on DSM. In 2021,
11 Nova Scotia ratepayers once again spent about \$1.5 billion on electricity, of which \$35 million was spent
12 on DSM. This equates to 2.3% of the total revenue which is a slight improvement upon 2020 but still
13 behind leading jurisdictions and utilities.

14
15 The Settlement Plan seeks to improve upon recent investment levels and lessen the gap with leading
16 jurisdictions by proposing 3.5% of NS Power's revenue go toward energy efficiency programming in 2023
17 (assuming revenue of \$1.5B) with reasonable investment growth thereafter. This is conservative in the
18 circumstances given the pilot investment in demand response and is generally aligned with the
19 percentage of revenue spent among the largest 52 largest American utilities, although it remains
20 approximately 29% below the average level among Massachusetts, Vermont, and Maine. E1 submits that
21 the Settlement Plan represents a reasonable increase from the 2020 and 2021 NS Power revenue
22 contributions, where NS Power spent 1.8% and 2.3% toward DSM, as indicated in Figure 4, (the majority
23 of which was energy efficiency programs), allocations which remain 30% and 11% below the average
24 energy efficiency revenue-based spending levels among the 52 largest American utilities, respectively.

1 Figure 4: 2021 Annual Electricity Investment in Nova Scotia

IN 2021, NOVA SCOTIANS PAID \$1.5 BILLION FOR ELECTRICITY.
HERE'S HOW THAT MONEY WAS USED:



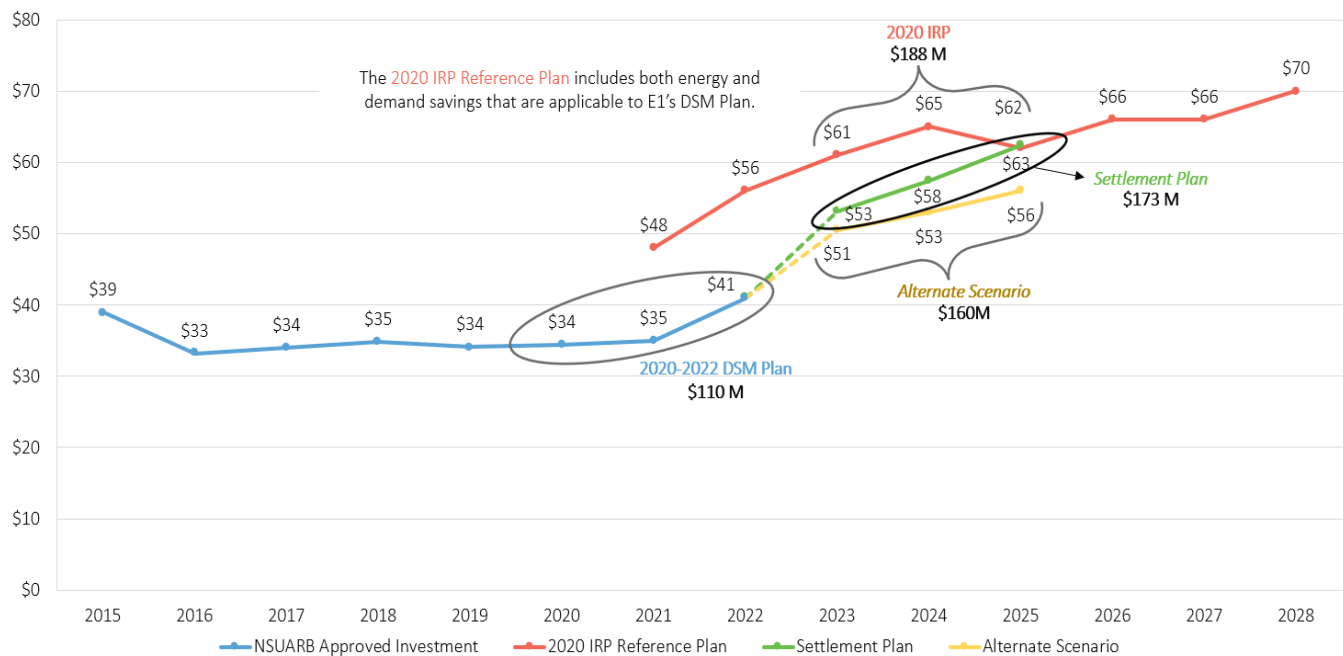
Source: NS Power 2021 Audited Financial Statements

8. THE NS POWER 2020 IRP

8.1 THE SETTLEMENT PLAN ALIGNS WITH THE NS POWER 2020 IRP

The Settlement Plan will enhance DSM deliverables and effectiveness by increasing DSM spending to a level that ensures unity with Nova Scotia's current and future energy landscape, while remaining aligned with, and rooted in, the 2020 IRP. It is important to recognize that the Settlement Plan remains founded upon the 2020 IRP's lowest net revenue option and deliberately employs an investment trajectory that promises DSM alignment with the 2020 IRP by 2025. The cumulative Settlement Plan investment level over the period of the Plan aligns generally, in aggregate, with the Reference Plan investment level (\$173M v. \$188M).

Figure 5: Comparison of the Settlement Plan & Alternate Scenario to the 2020 IRP



8.1.1 THE SETTLEMENT PLAN IS TRANSITIONAL

The Settlement Plan is intentionally transitional by providing enhanced programming that is responsive to recent legislative changes. It proposes an increase in DSM investment that is critical to counteracting lower investment levels of previous years. The Settlement Plan also ensures the level of DSM investment is brought to IRP levels in a reasonable period of time, thereby ensuring ratepayers are positioned to receive maximum benefits attributable to DSM and consistent with the IRP.

\$1.6M of the investment increase over the 2022 investment level is attributed to inflationary pressure. The remainder of investment increase reflects new or enhanced programming directed toward areas identified in the stakeholder consultation as those areas which would benefit from more targeted investment. Figure 6 illustrates the proposed investment ramp-up between 2022 and 2023:

Figure 6: Proposed Investment Ramp-Up Between 2022 and 2023

2023-2025 DSM Plan Settlement Plan

2022 Investment Ramp up to 2023	Millions \$
2022 DSM Investment Approved	41.0
Re-introduction of Low-Income Homeowner Program	8.1
Expansion of Services to Mi'Kmaq Communities	1.1
Re-introduction of Behaviour	1.1
Expansion for Small Businesses	1.5
Inflationary Increases (4%)	1.6
Wind Up of New Home Construction	(2.0)
Decrease in Existing Program Investments	(0.9)
Demand Response	1.5
2023 Settlement Plan Investment	53.0

8.2 THE EVOLUTION OF KEY ASSUMPTIONS POST-2020-2022 DSM PLAN

8.2.1 CARBON CONSIDERATIONS

For the first time in a DSM Resource Plan application, E1 is including the quantitative impacts of the avoidance of greenhouse gas emissions attributable to investments made in energy efficiency in calculating lifetime benefits associated with individual energy efficiency measures. This approach was directed by the NSUARB in its Order in Matter M08604, wherein it required E1 to, *"incorporate the value*

of avoiding CO₂e emissions in its DSM cost effectiveness analysis”³⁵. The inclusion of the quantitative impacts of the avoidance of carbon emissions is consistent and aligned with both provincial and federal legislative initiatives which have been introduced since the time of the last DSM Plan Application³⁶.

To reduce greenhouse gas emissions the *Environmental Goals and Climate Change Reduction Act* identifies energy efficiency programming as a primary area of focus³⁷. In accordance with the Board direction, and consistent with federal and provincial legislation related to GHG emission reductions efforts, E1 has undertaken a directed focus on quantifying and calculating the emissions reductions directly attributable to investment in energy efficiency measures. The Settlement Plan reflects first year carbon dioxide equivalent (CO₂e) emissions savings of 326 kt and lifetime CO₂e emissions savings of 1,742 kt valued at approximately \$170 million.

AVOIDED COSTS HAVE EVOLVED SINCE THE 2020 IRP

As noted earlier, given recent legislative and policy changes, coupled with the 2020 IRP study timeline, it is reasonable to assume that the IRP’s avoided costs are now no longer reflective of the current or future energy landscape in this province.

For the avoided costs of capacity and energy, E1 used 2020 IRP Reference Case Scenario 2.0C’s outputs.

CARBON

For the Settlement Plan, it remains E1’s position that it is reasonable to assign a value to carbon and related pricing avoidance. With this in mind, E1 determined the avoided costs of carbon for the purposes of the Settlement Plan by applying the federal trajectory pricing below and thereafter employing these values in assessing the affordability of the Settlement Plan (Table 6, below). Notwithstanding the uncertainty that currently surrounds the carbon credit market and any future ability to trade, the federal trajectory remains the most appropriate methodology to apply at this time.

³⁵ M08604

³⁶ *Environmental Goals and Climate Change Reduction Act; The Canadian Net-Zero Emissions Accountability Act*

³⁷ *Environmental Goals and Climate Change Reduction Act*, s. 7 The Government's goals with respect to climate change mitigation and adaptation and the reduction of greenhouse gas emissions are... (b) to support, strengthen and set targets for energy efficiency programming while prioritizing equitable access and benefits for low-income and marginalized Nova Scotians;

1 Table 6: Federal Carbon Pollution Pricing Benchmark Values Used for This Analysis

Year	Federal Carbon Pollution Pricing Benchmark (\$/tonne)
2020	\$30
2021	\$40
2022	\$50
2023	\$65
2024	\$80
2025	\$95
2026	\$110
2027	\$125
2028	\$140
2029	\$155
2030	\$170
2031-2063	Extrapolated using 2% annual inflation

2

3 The carbon prices outlined in Table 6, above, were applied to the estimated avoided carbon emissions

4 from DSM, determined using the Difference in Carbon Emissions (DICE) methodology, to determine the

5 avoided costs of carbon. The DICE method is similar to the development of avoided costs of energy and

6 capacity. The amount of carbon reduction due to DSM was calculated by comparing the IRP carbon

7 emissions between scenarios with, and without DSM that are otherwise the same. A savings-intensity was

8 then developed for each year in order to model levels of DSM that differ from what was modelled in the

9 IRP. The avoided cost of carbon in each year has been calculated by multiplying the Federal Carbon

10 Pollution Pricing Benchmark by the emissions intensity, determined using the DICE method. This resulted

11 in an avoided cost of carbon per MWh saved by DSM, which are based on a comparison between the IRP

12 Scenario 2.0C with Base-DSM, and with No-DSM. Both the savings intensity and the resultant avoided

13 cost of carbon are shown in Table 7, below.

14

15 Table 7: Carbon Savings Intensity (tonnes per MWh) and Avoided Cost (\$/MWh)

Year	Carbon Savings Intensity (tonne/MWh)	Avoided Cost of Carbon (\$/MWh)
2023	0.861	55.94
2024	0.898	71.83

Year	Carbon Savings Intensity (tonne/MWh)	Avoided Cost of Carbon (\$/MWh)
2025	0.632	60.00
2026	0.448	49.29
2027	0.355	44.35
2028	0.431	60.28
2029	0.393	60.92
2030	0.086	14.62
2031	0.159	27.51
2032	0.320	56.56
2033	0.360	64.98
2034	0.369	67.84
2035	0.269	50.52
2036	0.355	67.93
2037	0.288	56.18
2038	0.239	47.52
2039	0.218	44.21
2040	0.221	45.80
2041	0.158	33.33
2042	0.175	37.77
2043	0.182	40.07
2044	0.166	37.28
2045	0.179	40.88
2046-2063	0.179	Extrapolated using 2% annual inflation

8.3 RATE AND BILL CONSIDERATIONS & RATE AND BILL IMPACT ANALYSIS (RBIA) FOR 2023-2025

E1's RBIA for 2023-2025 indicates that DSM, and specifically its energy efficiency portfolio, is the only resource option available to ratepayers that generates true bill savings.

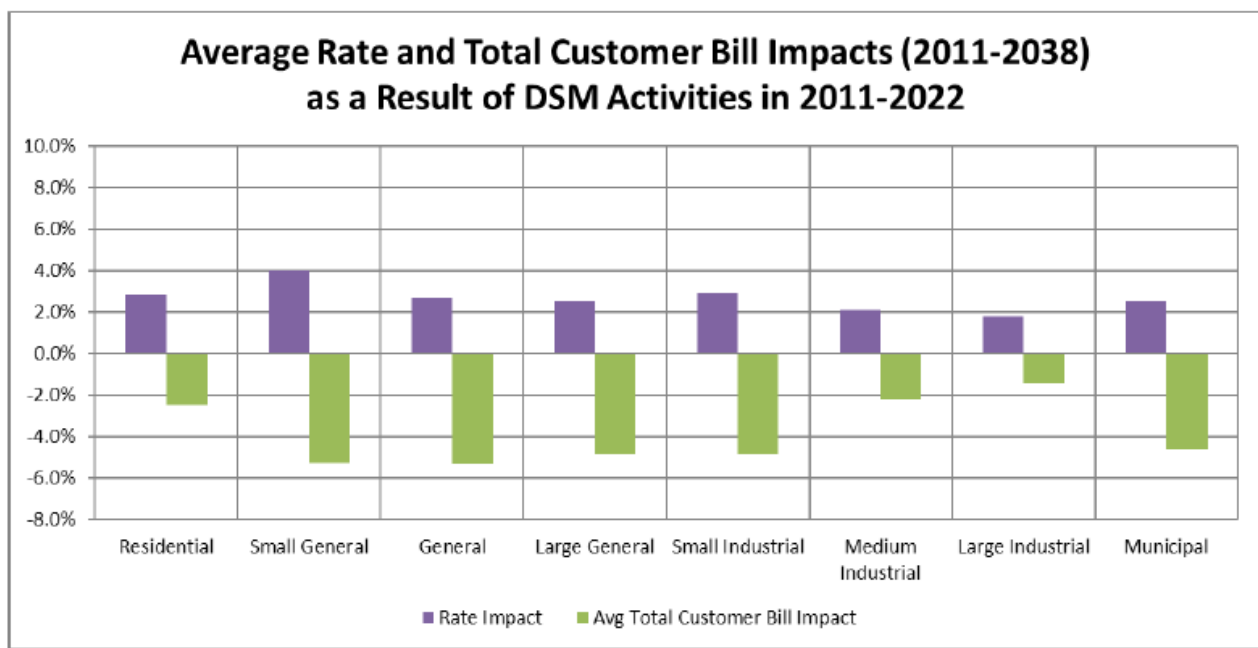
Expanding DSM through increased investment under the Settlement Plan will improve ratepayers' overall aggregate bill savings. While DSM expansion is not immune from upward rate pressure, the overall bill savings for participants outweigh any rate impacts from DSM that may occur. In time, the maximization of

customer participation will only serve to further mitigate rate impacts by increasing the total number of ratepayers who experience net bill reductions.

8.3.1 HISTORICAL RBIA

E1's 2021 Historical RBIA indicates that ratepayers are already positioned to accrue aggregate bill savings in excess of \$1.5 billion between 2011 and 2038 as a result of past DSM activities between 2011 and 2022. Figure 7 illustrates the average rate and bill impacts of DSM by rate class based on historical data.

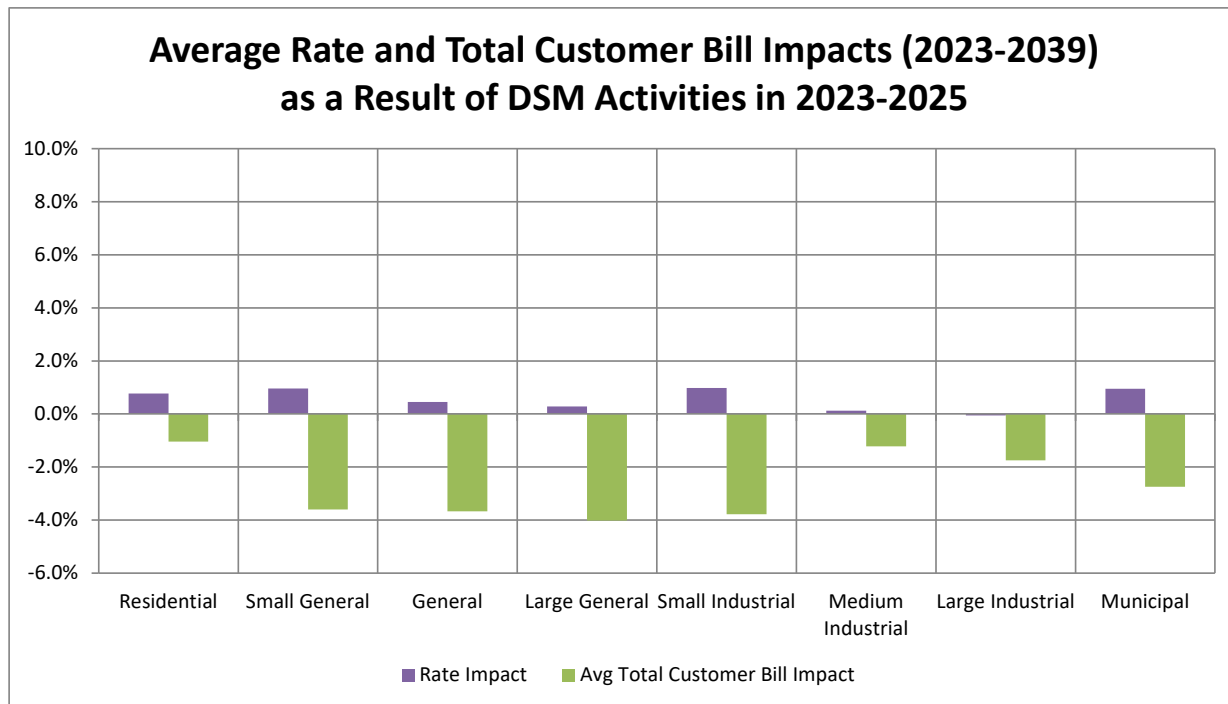
Figure 7: Average Rate and Bill Impacts (2011-2035) as a Result of DSM Activities in 2011-2022



8.3.2 2023-2025 RBIA

Investment at the Settlement Plan level would result in average rate impacts that range between -0.1% and 1.0% by rate class, averaged over the lifetime of measures (Figure 8). These figures are calculated relative to a scenario with no DSM as opposed to 2022 DSM levels. Average participants would see their bills reduced between 1.2% and 7.9%.

1 Figure 8: Average Rate and Total Customer Bill Impacts as a Result of DSM Activities in 2023-2025



2

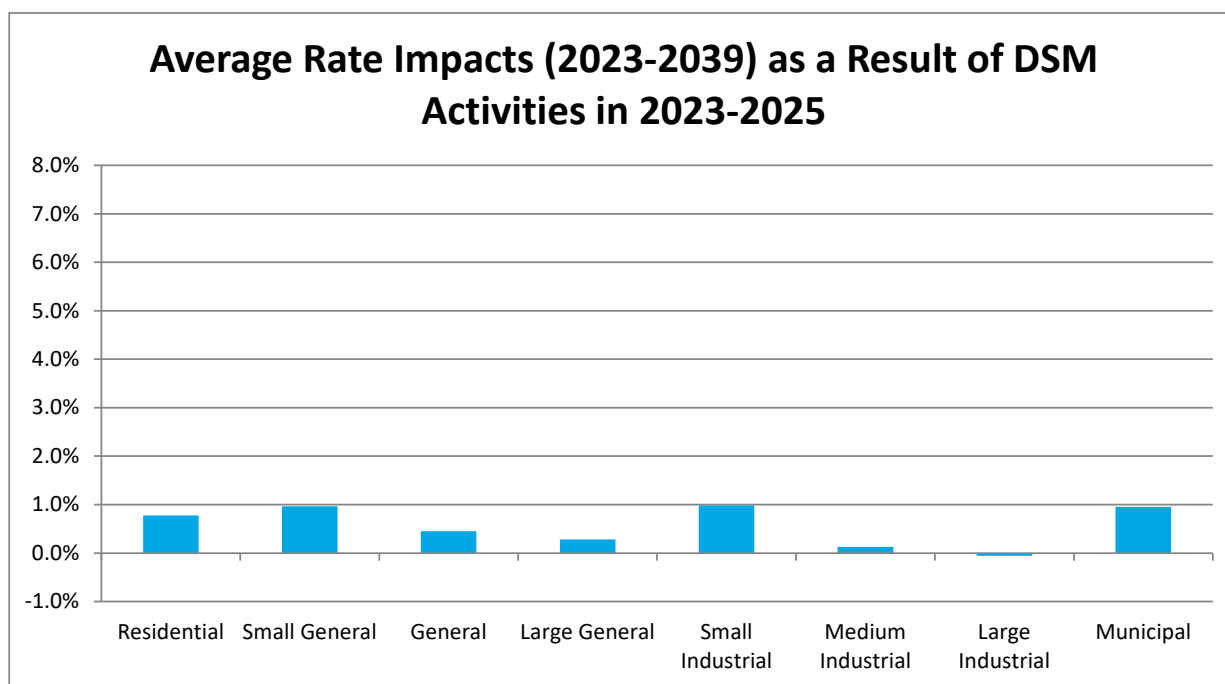
3 Figure 7 and Figure 8 illustrate 2023-2025 rate and bill impacts by rate class under the Settlement Plan.

4 Figure 9 and Figure 10 provide a rate and bill-specific breakdown. As can be seen, the Settlement Plan will

5 have minimal impact on rates but provides significant bill benefits for DSM participants and all customers,

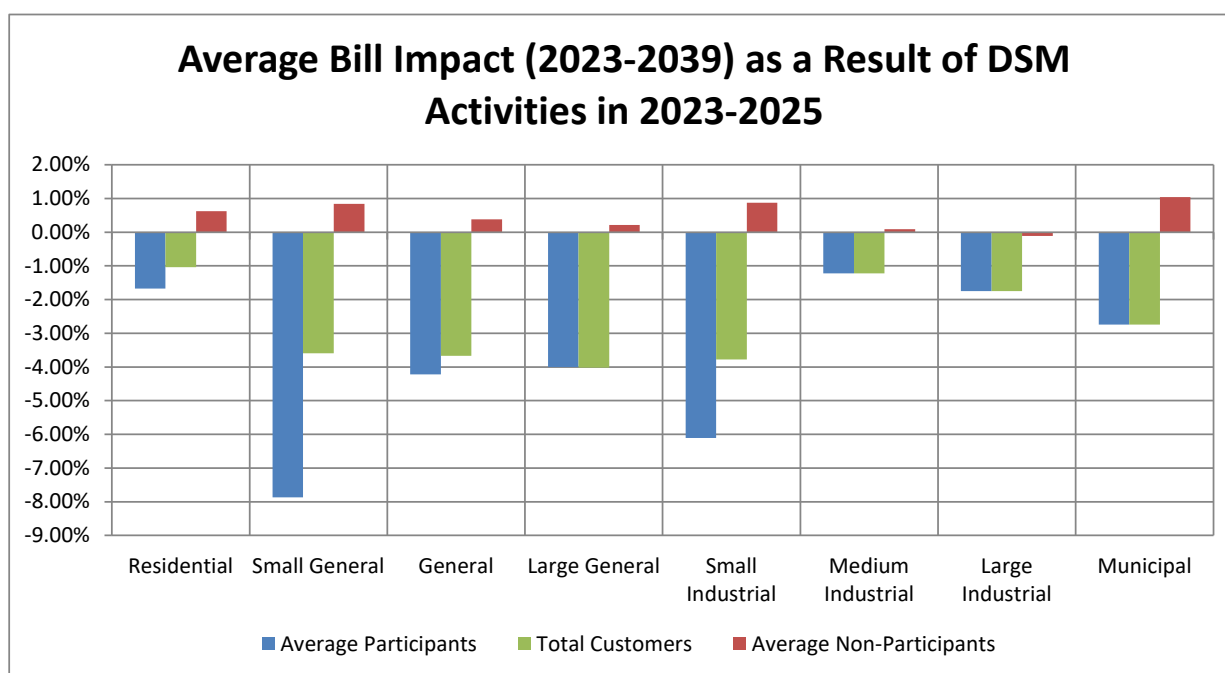
6 generally.

1 Figure 9: Average Rate Impacts (2023-2039) as a Result of DSM Activities in 2023-2025 (Settlement Plan)



2

3 Figure 10: Average Bill Impact (2023-2039) as a Result of DSM Activities in 2023-2025 (Settlement Plan)



RATE PRESSURE IS MINIMAL RELATIVE TO OTHER COSTS AND ONLY IMPACTED BY INCREMENTAL DSM

Using the 2021 Historical RBIA, DSM induced a rate pressure that ranged from 1.8 to 4.0% across all rate classes. As the 2022 DSM investment of \$41 million has already been approved, this investment is already rate-embedded and should not be double-counted. Thus, any rate pressure that follows an approval of the 2023-2025 DSM Plan will only be associated with the incremental portion of DSM investment above the 2022 level (i.e. incremental to \$41M per year). Moreover, any rate pressure due to the DSM incremental investment will be minimal in comparison to other costs and expenditures. DSM will continue to serve as both a short- and long-term investment and savings mechanism, but unlike other costs that create rate pressure, it is an investment that directly provides ratepayers with immediate long-term benefits. The Settlement Plan investment, as demonstrated by the RBIA, will generate \$543M in lifetime customer benefits.

8.4 DSM AS THE LEAST COST OPTION

Energy efficiency is affordable on the basis that it is the lowest cost fuel source available to NS Power and should for this reason be the first choice for ratepayers. However, a mere comparison of the cost of energy efficiency to the cost of other fuel sources does not illustrate the full cost-savings associated with increased investment in DSM. An increased investment in energy efficiency corresponds with a decrease in collateral costs which are ultimately passed on to ratepayers when an investment is made in fuel sources other than energy efficiency.

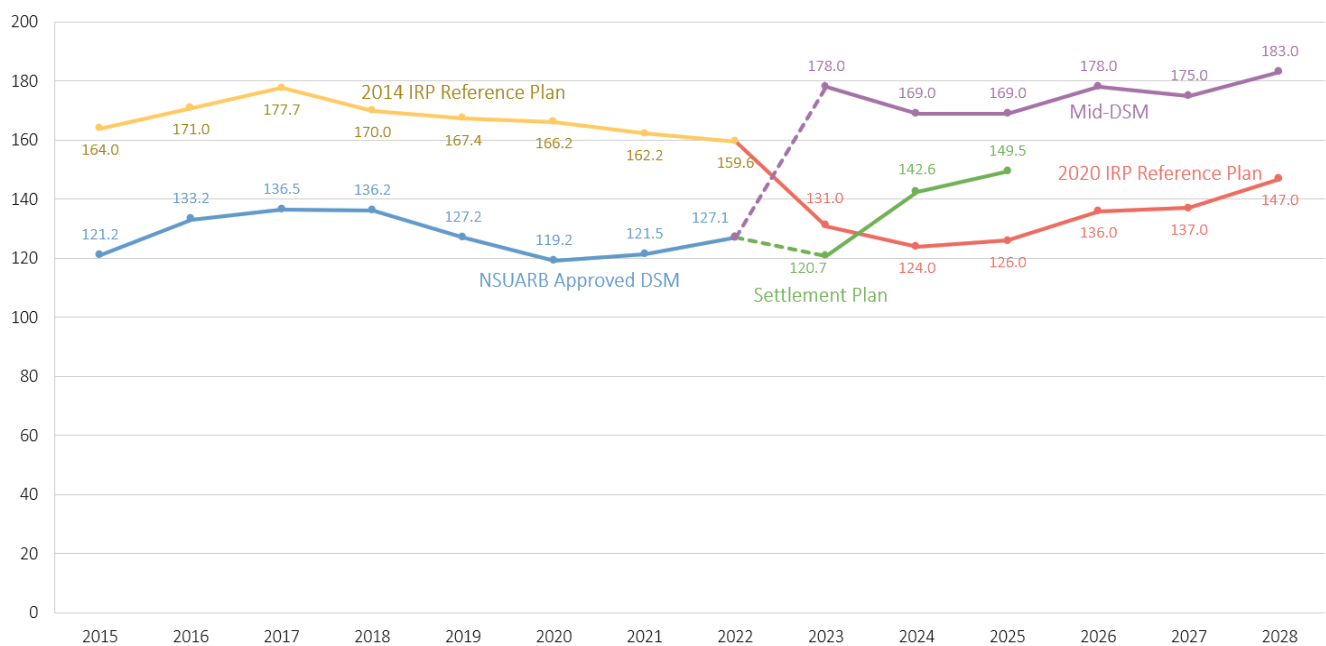
8.4.1 THE INCREASE IN ENERGY SAVINGS ACCOMPLISHED BY THE SETTLEMENT PLAN ALIGNS WITH THE TREND IN OTHER JURISDICTIONS

The trend in most jurisdictions has been to increase investment levels in energy efficiency. The level of investment in energy efficiency proposed in the Settlement Plan is consistent with such trends. A study of 51 utilities in the United States showed a 20% increase in energy savings between 2017 and 2020³⁸. The increase in energy savings of 412.7 GWh proposed by the Settlement Plan is an increase of 12% from the energy savings of the approved 2020-2022 Plan of 367.8 GWh and is consistent with the trend in other jurisdictions.

³⁸ ACEEE 2020 Utility Scorecard.

The Settlement Plan is a step towards achieving the optimal level of DSM, which will set ratepayers on the path to realizing the maximum benefits of energy efficiency in an incremental manner. Incorporating the level of energy savings identified in the IRP, the Settlement Plan establishes an objective DSM target to provide the greatest benefits to Nova Scotians in the long-term. Since 2015, the approved level of energy efficiency has been lower than the optimal level identified in the IRP, resulting in lost benefits for ratepayers. Figure 11 illustrates the difference in energy savings levels (GWh) between the 2014 and 2020 IRP Reference Plans and the approved 2020-2022 Plan.

Figure 11: Comparison of the Settlement Plan & Mid-DSM to the 2014 & 2020 IRP (GWh)



8.5 THE COMPARATIVE COST OF DSM TO OTHER FUELS AND RESOURCE SOURCES

Energy efficiency continues to be the lowest cost option as compared to any alternate fuel source used for the production of electricity in Nova Scotia. Table 8 shows the comparison of the cost of DSM to NS Power's average fuel costs.

1 Table 8: Comparison of the Cost of DSM to NS Power's Average Fuel Costs

Year	DSM Cost			NS Power Avg. Cost of Fuel			Difference Between DSM & Fuel	
	(\$ per kWh)	Change	Change (%)	(\$ per kWh)	Change	Change (%)	(\$ per kWh)	Fuel as % of DSM
2015	0.018	-	0%	0.049	-	0%	0.031	171%
2016	0.016	(0.002)	(11%)	0.045	(0.004)	(7.3%)	0.029	183%
2017	0.019	0.003	19%	0.043	(0.002)	(3.9%)	0.024	129%
2018	0.019	-	0%	0.056	0.013	29.4%	0.037	196%
2019	0.019	-	0%	0.059	0.003	5.2%	0.040	212%
2020	0.021	0.002	11%	0.067	0.008	13.2%	0.046	219%
2021	0.023	0.002	10%	0.075	0.008	11.9%	0.052	226%

2
3 The cost of DSM per kWh has been consistently lower than the average cost of fuel for the last seven
4 years. On average, during this time period, the cost of fuel to NS Power has been 187% more than the
5 cost of DSM.

6
7 It is in the best interest of ratepayers to invest in energy efficiency during a time where the first-year unit
8 cost of energy efficiency averages \$0.39/kWh range. Unit costs have increased from \$0.23/kWh during
9 the 2016 Plan to \$0.27/kWh in 2019 and have risen to \$0.31/kWh in 2022. The Base DSM resource cost in
10 the 2020 IRP Reference Plan assumes a unit cost of \$0.467/kWh – some \$0.077/kWh higher than the unit
11 costs proposed under the Settlement Plan. Nova Scotia ratepayers have already foregone the opportunity
12 to benefit from energy efficiency at lower unit costs due to past investment levels having been below
13 those prescribed within the IRP. Front-loading the DSM investment now during the 2023-2025 period
14 mitigates the future effects of increasing energy efficiency costs, which is supported by pricing trends,
15 while also offsetting past lower investment levels in the short-term.

17 8.6 ENERGY EFFICIENCY IS THE LEAST RISK OPTION

18 Energy efficiency is a low-risk energy investment as there is:

- 19 • Certainty with respect to the level in investment;
- 20 • No unexpected costs associated with an investment in energy efficiency; and
- 21 • No variability in the cost of energy efficiency during each Plan term.

1 Spending on energy efficiency is capped for the duration of each term at the level of investment
2 approved by the Board. Consequently, ratepayers have certainty during each term with respect to the
3 cost they will bear in relation to DSM.

4
5 There are unexpected costs incurred through investment in other fuel sources which are not associated
6 with DSM. There is greater uncertainty and volatility with respect to the cost of other fuels.

7
8 The reliability and consistency of E1's programs make an investment in energy efficiency less costly and
9 less risky for ratepayers. E1 has consistently met its targets within the Board-approved level of spending.
10 As spending on DSM is capped for the three years of each DSM Plan, ratepayers will not bear the cost of
11 an unexpected increase in energy efficiency expenditures.

12
13 Ultimately, the unexpected costs associated with higher risk fuel sources are passed on to ratepayers.

14
15 DSM also bears none of the risks associated with variable fuel prices. E1 has historically administered
16 efficiency programs with a lifetime unit cost more consistently stable than that of other fuel sources, as
17 indicated in Table 8, above. Investment in other fuel sources is subject to increased costs incurred
18 through rate impacts from increased energy prices and other market forces. This is a further cost borne
19 by ratepayers which is reduced through investment in electricity efficiency.

20 21 8.7 LONG-TERM COST SAVINGS

22 Each year in which the approved investment level of DSM is below the level established in the IRP, Nova
23 Scotians forego the full short- and long-term benefits possible through energy efficiency.

24
25 The cumulative impact of the historic underinvestment in energy efficiency has been costly to NS Power's
26 ratepayers. Consistent under-spending on electricity efficiency has cost ratepayers approximately \$328
27 million which could have been avoided had investment in energy efficiency approached the levels set out
28 in the IRP. Table 9 and Table 10 illustrate the costs incurred since 2015 as a result of investment in energy
29 efficiency falling short of IRP levels.

1 Table 9: Comparison of First-Year Energy Savings as compared to 2013 Potential Study

EfficiencyOne Comparison of First-Year Energy Savings as compared to 2013 Potential Study									
Year	2015	2016	2017	2018	2019	2020	2021	2022	Total
Potential Study Savings –IRP Resource Plan – Mid Case (GWh)	164.0	171.0	177.7	170.0	167.4	166.2	162.2	159.6	1,338.1
NSUARB-approved Levels (GWh)	121.1	133.2	136.5	136.2	127.2	119.2	121.5	127.1	1,022.1
Shortfall (GWh)	(42.8)	(37.8)	(41.2)	(33.8)	(40.2)	(47.0)	(40.7)	(32.5)	(316.0)
Measure Life (Yrs)	12.9	15.9	16.0	16.1	12.9	14.1	14.2	14.4	
Total Shortfall over Lifetime (GWh)	(552.1)	(601.0)	(659.2)	(544.2)	(518.6)	(662.7)	(577.9)	(468.0)	

2

3 Table 10: Total Fuel Costs Incurred due to savings shortfall as compared to 2013 Potential Study

Year	Savings (GWh)								Total GWh	Cost of Fuel per kWh	Total Costs Incurred due to Shortfall (\$ millions)
2015	(42.8)								(42.8)	0.049	2.1
2016	(42.8)	(37.9)							(80.7)	0.045	3.6
2017	(42.8)	(37.9)	(41.2)						(121.9)	0.043	5.3
2018	(42.8)	(37.9)	(41.2)	(33.7)					(155.6)	0.056	8.8
2019	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)				(195.8)	0.059	11.6
2020	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)			(242.8)	0.067	16.3
2021	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)		(283.5)	0.075	21.3
2022	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(316.0)	0.075	23.7
2023	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(316.0)	0.075	23.7
2024	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(316.0)	0.075	23.7
2025	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(316.0)	0.075	23.7
2026	(42.8)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(316.0)	0.075	23.7
2027	(38.5)	(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(311.7)	0.075	23.4
2028		(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(273.2)	0.075	20.5
2029		(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(273.2)	0.075	20.5
2030		(37.9)	(41.2)	(33.7)	(40.2)	(47.0)	(40.7)	(32.5)	(273.2)	0.075	20.5
2031		(35.6)	(41.2)	(33.7)	(36.2)	(47.0)	(40.7)	(32.5)	(266.9)	0.075	20.0
2032			(41.2)	(33.7)		(47.0)	(40.7)	(32.5)	(195.1)	0.075	14.6

Year	Savings (GWh)								Total GWh	Cost of Fuel per kWh	Total Costs Incurred due to Shortfall (\$ millions)
2033	(33.7)	(47.0)	(40.7)	(32.5)	(153.9)	0.075	11.5				
2034	(1.8)	(4.7)	(40.7)	(32.5)	(79.7)	0.075	6.0				
2035			(8.1)	(32.5)	(40.6)	0.075	3.0				
2036				(13.0)	(13.0)	0.075	1.0				
(552.1) (604.1) (659.2) (541.0) (518.6) (662.7) (577.9) (468.0) (4,583.6) 328.4											

1 Numbers may not sum due to rounding.

2

3 The investment level set out in the Settlement Plan is a step toward the optimal level established in the
4 2020 IRP. Now is the time to correct historic underinvestment and move the level of DSM closer to the
5 optimal level. Should the level of investment continue to be below the level established in the 2020 IRP,
6 Nova Scotians will continue to incur greater costs which could have been avoided through optimal
7 investment.

9. UNDERSERVED MARKETS AND DIVERSE COMMUNITIES

As a Guiding Principle under the Settlement Plan, E1's programs and initiatives must be accessible on an equitable and non-discriminatory basis to all ratepayers. To accomplish this, it is critical that E1 develop and implement accessible programs and initiatives in markets and communities that have been traditionally underserved by DSM measures. For the first time, E1 applied a design objective in the development of the DSM Plan to achieve 17-22% of total investment in low-income support. This shift in approach aligns with the most recent census data illustrating the prevalence of low-income in Nova Scotia³⁹.

The Settlement Plan will feature program enhancements aimed at increasing overall accessibility of DSM programs and the removal of barriers that inhibit community participation. Building upon past successes and lessons learned, the Settlement Plan leverages the effectiveness of existing barrier mitigation strategies and extends successful programs, while continuing to develop and implement new initiatives designed to further reduce the impact of DSM barriers and enhance overall accessibility for customers. The Settlement Plan will also include a significant expansion in education and outreach initiatives for Nova Scotia's diverse communities under E1's Enabling Strategies.

9.1 DSM ACCESSIBILITY AND PARTICIPATION BARRIERS

The 2020-2022 DSM Plan identified numerous ways in which certain markets and communities in Nova Scotia are impeded from accessing and participating in DSM programs, from both a Residential and BNI sector perspective. These barriers remain ever-present today. In a residential context, primary barriers to program participation include:

- affordability and costs, particularly up-front costs or investment;
- a dearth of information and awareness when it comes to energy efficient technologies and the benefits associated therewith;
- the challenges associated with time and resources required to implement upgrades;
- the requirement to split incentives with other parties; and
- the lack of trust in free services being offered, among others.

³⁹ Census Data , 2016, <https://www12.statcan.gc.ca/census-recensement/2016/>

In a BNI context, primary barriers encompass:

- affordability and costs, particularly up-front costs or investment;
- internal competition for capital;
- payback periods; and
- lack of resources and lack of information and awareness of energy efficient technologies and benefits.

9.2 THE SETTLEMENT PLAN WILL EXPAND PROGRAMMING FOR UNDERSERVED MARKETS AND DIVERSE COMMUNITIES

Increased investment in DSM programming for low-income, Mi'kmaw and diverse communities is both urgent and in alignment with the requirement for DSM program inclusion. Ensuring programming equity and delivery to groups that have traditionally experienced program accessibility challenges in Energy Efficiency offerings is responsive to broader societal issues, most notably the prevalence of low-income in Nova Scotia and environmental discrimination⁴⁰.

Under the Settlement Plan, E1 will be allocating \$35.8 million toward DSM programs for underserved markets and diverse communities, amounting to a 177% growth in funding. This increase in DSM investment intended for low-income and diverse markets is intentionally close to three times the 2020-2022 investment level of \$12.9 million and reflective of E1's commitment to equitable and non-discriminatory program delivery. With this in mind, E1 will now allocate 21% of the total Settlement Plan investment toward low-income programming – a substantial increase from the average of 8% seen during the 2015 to 2020 timeframe. Further, increased support for Mi'kmaw communities is also provided for under the Settlement Plan with the investment levels increasing to \$7.0 million. Notably, the new Affordable Single-family Home program component constitutes a considerable portion of this growth in investment and will offer significant savings for the families who need it most with an investment level of \$24.7 million.

Under the Settlement Plan, the following legacy and new program components are planned:

- Mi'kmaw and Diverse Community Program Components and Initiative – including the Mi'kmaw Home Energy Efficiency Project (MHEEP), the continuation of support for a Business Development

⁴⁰ Census Data 2016, <https://www12.statcan.gc.ca/census-recensement/2016/>

1 Manager (BDM) to help navigate services for business and communities under the small business
2 category, and potentially the introduction of a new Roving Onsite Energy Manager (OEM) and
3 additional training and partnership opportunities. The Diverse Communities Initiative will
4 encompass both Mi'kmaw and African Nova Scotian communities and include training, and
5 partnership opportunities.

- 6 • Low-Income Community Program Components, Activities, and Initiatives – including the
7 continuation of the Affordable Multi-family Housing & Non-Profit Organizations (AMH) program
8 component, and the re-introduction of the Affordable Single-family Homes program component,
9 which has been absent since 2014-2015.
- 10 • Other/Related Program Components – including a new Residential Behaviour program
11 component, the continuation of the residential Efficient Product Installation program component
12 and related initiatives under the Small Business Energy Solutions program component that was
13 introduced in late-2021.

10. DEMAND RESPONSE

The 2020 IRP found that Demand Response (DR) was a long-term cost-effective and flexible grid resource for the utility and selected its inclusion. In an effort to align with the 2020 IRP's capacity goals and enhance existing demand reduction efforts, for the first time E1 has included a dedicated DR pilot portfolio under the Settlement Plan. E1's DR portfolio is founded on ongoing cooperation with NS Power that builds upon existing collaborative efforts. Under the Settlement Plan, an investment of \$10.0 million toward DR pilot programming is included with increased annual spending of \$1.5 million, \$3.5 million, and \$5.0 million in succession between 2023 and 2025.

10.1 DEMAND RESPONSE IS A KEY UTILITY RESOURCE THAT BUILDS UPON EXISTING COLLABORATION

Demand Response serves as a key resource for utilities in that it modifies and reduces system coincident peak demand by shifting the load demand from peak timeframes to preferred alternatives. It can be called upon when needed to reduce and/or adjust load when it would be most impactful (e.g. winter peak hours or during specific power or grid events).

Since 2019, E1 and NS Power have worked collaboratively to develop, assess and evaluate DR pilot programs in an effort to ascertain feasibility and scalability. Presently, E1 and NS Power are collaborating on two pilot programs for the 2021-2022 timeframe; therefore, pilot DR programming under the Settlement Plan builds upon existing collaborative efforts.

With the formalization of the 2020 IRP, the Board accepted NS Power's filings regarding the long-term value associated with DR and the need to increase DR capacity, capabilities and spending. The 2020 IRP calls for 81 MW of DR capacity by 2045, and the Settlement Plan projects a DR capacity of 17.9 MW by the end of 2025. The DR portfolio included in the Settlement Plan has been informed by the recent experience of E1 in developing and implementing pilots in 2021. DR has proven challenging in that it is new in E1's portfolio and has required significant time to develop and implement. Recognizing this, E1 engaged the expertise of Guidehouse to lead the development and modelling of the 2023-2025 DSM Plan DR portfolio.

In Nova Scotia, DR could prove critical in the years ahead as a means of reducing winter peak demand and lessening the need for capital expenditures related to increased generation as the population in this

1 province continues to grow; however, the current benefits as examined through the DSM Plan
2 development process have indicated that the utility costs for DR programming outweigh the benefits. The
3 quantifiable benefits used for assessment include the capacity avoided costs from the 2020 IRP Reference
4 Plan 2.0C and the transmission and distribution avoided costs as provided by NS Power outside of the IRP
5 process. While continued exploration of DR offerings may yield additional benefits, not unlike energy
6 efficiency, any benefits included in cost effectiveness testing must be quantifiable and determined
7 appropriate for inclusion.

9 10.2 DEMAND RESPONSE SHOULD BE TREATED AS A PERFORMANCE 10 INDICATOR

11 As a new portfolio item that will introduce an additional 17.9 MW of capacity to the grid by the end of
12 2025, DR will become an important contributor toward the overall 96.7 MW of cumulative system-peak
13 demand savings projected under the 2023-2025 DSM Plan. Likewise, DR complements demand reduction
14 activities under the Settlement Plan that comprise the majority (approximately 81.5%) of the overall
15 system-peak demand savings impact. It is, therefore, E1's position that DR, as an innovative pilot
16 portfolio, should be assessed as a Performance Indicator between 2023 and 2025 and reassessed
17 thereafter.

11. PERFORMANCE TARGETS

E1's success in implementing an approved DSM Plan is evaluated through Performance Targets. The Standardized Filing Framework sets out the performance targets and thresholds which must be met through the execution of the DSM Plan. The Board-Approved Performance Targets are:

- Cumulative annual energy savings; and
- Cumulative annual peak demand savings.

Where a minimum of 90% achievement is reached with respect to each of the cumulative annual energy savings and cumulative annual peak savings, E1 is deemed to be in substantial compliance with the Performance Targets. The Performance Targets apply, and are evaluated, to the period of the Board-Approved Supply Agreement, rather than annually.

Evaluation of E1's compliance and success in implementing the approved DSM Plan will be monitored through Quarterly Reports and Annual Progress Reports.

For the first time, E1 is proposing targeted Demand Response activities under its Settlement Plan. These DR activities are intended to facilitate direct electricity customer response on a real-time basis to better align demand with existing NS Power system capacity. E1 proposes to work collaboratively with NS Power in the implementation of these measures. Given their intended introduction to DSM activities for the first time in the Settlement Plan, E1 proposes that the targeted reduction of 17.9 MW over the 3-year Plan be established as a Performance Indicator defined within the Supply Agreement.

11.1 PERFORMANCE TARGETS IN THE SETTLEMENT PLAN

The Settlement Plan sets a target for cumulative annual energy savings of 412.7 GWh and cumulative annual peak demand savings of 78.8 MW.

12. PROPOSED CHANGES TO HISTORICAL RATE & BILL IMPACT ANALYSIS AND UPDATE ON PERFORMANCE ALIGNMENT STUDY

12.1 HISTORICAL RATE AND BILL IMPACT ANALYSIS

Currently, E1 files a historical RBIA on, or before, October 31 of each year. The historical RBIA estimates the high-level, long-term impact to rates and bills of all DSM activities up to and including those of the previous calendar year, as well as any future DSM investments that have been approved by the NSUARB. In addition, E1 files a forward looking RBIA in conjunction with each DSM Plan Application. The latter is used to provide guidance on the impact on future rates and bills associated with the DSM Plan activities proposed under the Application. Currently, the historical RBIA has been set as a Performance Indicator (“PI”) under the terms of the Supply Agreements. PIs are generally used as guidance material within E1. The Supply Agreement defines them as:

Performance Indicators are management tools that provide information to allow an organization to take action to help it deliver on performance targets.

The preparation and development of the historical RBIA filed annually consumes considerable time and resources of the organization, and generally appears to have limited utility to stakeholders during a three-year Plan cycle. While the historical RBIA has been used to inform decision making by stakeholders during Plan Applications, it has generally been treated as an informational filing during each of the three (3) years of a DSM Plan. E1 is proposing to alter its annual filings to eliminate the filing of the historical RBIA in any year other than a DSM Plan Application year. E1 submits that the elimination of the historical RBIA will have minimal impact on stakeholder assessment of ongoing DSM Plan performance and its elimination will result in internal cost savings to E1 which would otherwise be borne by ratepayers.

12.2 PERFORMANCE ALIGNMENT STUDY IMPLEMENTATION

The Board, in its decision in M09096, required E1 “to file terms of reference for the investigation of overestimation of costs by October 31, 2019, and to conclude the investigation and file a report with the Board by March 31, 2020”⁴¹. In response to this Board directive, E1 engaged KPMG to conduct the Performance Alignment Study (“Alignment Study”) which was filed with the NSUARB on April 21, 2020.

⁴¹ Board Order, M09096, September 6, 2019, page 2

On May 25, 2020, Synapse Energy Economics Inc. provided comments with respect to the Alignment Study, and in particular four (4) recommendations⁴²:

1. We agree that the mid-year modification process could be improved. For example, it appears that an annual budget reconciliation process would be helpful in Nova Scotia.
2. We find the jurisdictional review in the study to be too constrained. We are aware of other jurisdictions that deal with underspending issues and can make mid-term budget modifications, including energy efficiency program administrators in Massachusetts and Rhode Island. We encourage E1 to examine practices in additional jurisdictions to inform the improvements.
3. We support the study's recommendation to enhance the current reporting to better inform mid-year modifications, especially to include the latest spending status in the quarterly report.
4. We concur that E1 should improve its current internal vetting process for developing customer participation estimates by providing clear rationale and justification.

The Board directed that E1 consult with Synapse and the DSM Advisory Group to appropriately implement those recommendations.

Following is a synopsis of the activities undertaken by E1 to address these concerns:

Response to recommendations #1 and #3:

- Forecast information:
 - Quarterly reports - to include current year end forecast information (savings and spending).
 - Annual progress report - to include current Plan period forecast information (savings and spending).
- Participation information:
 - Quarterly reports – to include current year participation estimates and results.
 - Annual Progress Reports – to include Plan period participation estimates and results – by individual Plan year and progress towards three-year Plan as filed participation rates.

Implementation: Additional forecast and participation information in E1's DSM Quarterly and Annual Progress Reports has been included since the Q2 2021 Report.

⁴² M09750, Synapse Energy Economics Inc. Comments May 25, 2020, page 5

Response to recommendation #2:

As part of the development of the 2023-2025 DSM Plan, E1's consultant Guidehouse conducted a jurisdictional scan to identify best practice methodologies for forecasting DSM Plan participation. The scan included a combination of interviews and research, from a total of five North American program administrators, addressing the following topics:

- Sources of information used to forecast participation;
- Data structures to codify participation estimates;
- Internal review processes;
- Degree of automation/human expertise and synthesis of data sources; and
- Predicting market volatility.

The results of the Guidehouse engagement are provided as Attachment 3 of Appendix A.

Response to recommendation #4:

E1 commits to an improved internal vetting process for DSM Plan development including provision of clear rationale and justification for customer participation estimates. This information has been incorporated into the development of the 2023-2025 DSM Resource Plan and is referenced in the attached 2023-2025 DSM Plan as Appendix A.

13. ALTERNATE SCENARIO

Pursuant to the Board directive,⁴³ E1 is required to file one or more alternate scenarios (the “Alternate Scenario”) in addition to its Settlement Plan filing.

In the stakeholder engagement process preceding this Application, E1 considered and modelled various scenarios, with both higher and lower investment levels. Directionally, most stakeholder engagement signaled the need for increased DSM based, in part, on the 2020 IRP Reference Plan, and the subsequent legislative amendments which introduced more aggressive scheduling of fossil fuel electricity production shutdowns.

In compliance with the Board’s directive, E1 is providing this Alternate Scenario, as a fully costed DSM scenario in accordance with the Standardized Filing Requirements.

13.1 OVERVIEW

The Alternate Scenario represents a total investment in energy efficiency and demand reduction of \$160.1 million over the 2023-2025 DSM Plan. The scenario projects 4,469 GWh of lifetime energy savings utilizing a portfolio with an average measure life of 12.6 years. This represents first year energy savings of 377.3 GWh or 1.1% energy savings against NS Power’s load and approximately 12% less energy savings than accruing under the Settlement Plan. This scenario was developed with an average first year unit cost of \$0.41/kWh.

E1 would note that the alternate scenario presentation is subject to the same limitations and comparisons as the Settlement Plan vis-à-vis the impact of avoided costs. The conservative avoided costs reflected in IRP Reference Plan 2.0C result in an understatement of the potential benefits resulting from the scenario generally.

⁴³M06733, 2016-2018 DSM Plan, NSUARB Order, October 7, 2015

14. CONCLUSION

The Settlement Plan has been developed utilizing the historical knowledge and expertise of E1 in the best interests of Nova Scotia ratepayers. The Plan incorporates the accumulated market knowledge and intelligence collected by E1 over the years of operating the Efficiency Nova Scotia franchise. This accumulated knowledge is vital to the development of a cost-effective and realistic DSM portfolio.

The Settlement Plan, through an investment of \$173.0 million, will generate 412.7 GWh of annual energy savings resulting in benefits of \$543 million or costs NS Power will not incur and therefore have no need to recover from ratepayers. The Settlement Plan investment will also introduce 96.7 MW of cumulative system-peak demand savings to the grid by 2025 through energy efficiency and demand response initiatives.

The Settlement Plan achieves the following four key objectives in a manner which is affordable for Nova Scotians:

1. Supports the implementation of a long-term energy strategy that is in the best interests of Nova Scotia ratepayers;
2. Supports and is aligned with federal and provincial climate change initiatives and legislation;
3. Promotes an equitable, accessible and non-discriminatory portfolio of demand side management measures; and
4. Delivers a DSM portfolio that is reflective of the current Nova Scotia energy landscape.

Evidence

Attachment 1: Barriers to Participation & Mitigating Strategies

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1 Table 1: Residential Sector Barriers to Participation & Mitigating Strategies

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
EFFICIENT PRODUCT REBATES	Appliance Retirement	Removal and responsible recycling of old, inefficient appliances and replacement with energy efficient appliances.	Includes all residential customers including low-income, diverse communities, and renter customer groups.	<u>Affordability</u>: the cost difference between efficient products and less efficient products can create a participation barrier. This is addressed through financial incentives to customers for each retired appliance. For qualified low-income participants of the HomeWarming Program, appliance replacement and installation are provided at no-cost. <u>Accessibility</u>: coordinating appliance purchases, deliveries, and retirements can be overly burdensome and result in deferral of the removal or replacement of inefficient appliances. This is addressed through an easy to access, turnkey delivery approach, providing flexibility in appointment bookings (i.e. email, phone, or online booking). <u>Lack of information</u>: lack of familiarity with energy efficient products and appliances, which is addressed through delivery agent management of all aspects of appointment booking, pick-ups, transportation, and delivery/decommissioning of appliances. <u>Lack of trust</u>: some potential participants do not trust a free service; EfficiencyOne (E1) markets the program to provide confidence that the service is legitimate. This is further supported through E1 website updates and marketing through various platforms.
	Instant Savings	Rebates on energy efficient products through participating retail stores.	Residential customers, including owner-occupied and renters, that purchase products through retail channels.	<u>Affordability</u>: the cost difference between efficient products and less efficient products can create a participation barrier. This is addressed through point-of-sale rebates (offered in-store and online), providing a reduced upfront price for the more efficient alternative. <u>Awareness & lack of information</u>: some potential participants may not be aware of the benefits of energy-efficient products or may have a lack of knowledge around how to choose and install energy efficient products and appliances. This is addressed through the presence of in-store ambassadors that demonstrate products, educate customers on benefits of energy efficiency, and display easy-to-decipher marketing messaging so customers can easily recognize eligible products in-stores. This is further supported through E1 website updates and marketing through various platforms. <u>Accessibility & short decision period</u>: replacement of failing equipment can occur quickly resulting in lost opportunities. In the absence of widely available, discounted energy efficient products, consumers are likely to choose inefficient alternatives. This is

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
EFFICIENT PRODUCT REBATES	Instant Savings			addressed through program prominence and widescale availability (across Nova Scotia) of the service. E1's delivery agent encourages, and recruits, retailers to participate and provides training to retailers on energy efficient products as well as for additional E1 services.
EXISTING RESIDENTIAL	Affordable Multi-family Housing and Non-Profit Organizations	Offers property owners of existing residential facilities that provide affordable housing in Nova Scotia access to energy efficiency audits, contractors, and rebates for the completion of energy efficiency projects.	For-profit and non-profit rental housing, shelters, transition houses, housing co-operatives, and non-profit services such as food banks and community outreach centres.	<u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments), addressed by focusing on helping low-income renters and non-profits, who provide shelter, to reduce utility bills and stabilize rents. Through this program component, E1 provides financial assistance through rebates on implemented upgrades. <u>Awareness & resources</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits as well as a lack of time/human resources for project management, contractor management, and upgrade implementation. This is addressed through project management support and energy audits performed by qualified professionals, who educate and inform customers on upgrades. This is further supported through E1 website updates and marketing through various platforms. <u>Split incentive</u>: when landlords are not paying for utilities (specifically heating), they are often not motivated to implement energy efficiency upgrades to the building and/or equipment. Regardless of who pays the utility bills, there are benefits (more efficient equipment and building envelopes, installed at no-cost, and lower utility bills) for both landlords and tenants. Oftentimes, upgrades contribute to improved overall comfort and performance of low-income housing stock, providing benefits for tenants of affordable housing units.
	Efficient Product Installation	Direct installation of low-cost energy efficient upgrades at no cost to the participant.	Serves all types of residential dwellings in Nova Scotia, including single detached homes, semi-detached homes/duplexes, townhouses, mobile/mini homes, rental housing, and	<u>Affordability</u>: the cost difference between efficient products and less efficient products can create a participation barrier. This service addresses the affordability barrier providing installations by trained professionals of energy efficient products at no-cost to participants. <u>Awareness & resources</u>: some potential participants may not be aware of the benefits of energy-efficient products as well as a lack of time/human resources for project management, contractor management, and upgrade implementation. Efficient Product Installation addresses this through the provision of qualified installers that engage directly with customers during home visits, demonstrating energy efficient products

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
EXISTING RESIDENTIAL	Efficient Product Installation		other multi-family residences such as apartments and condominiums.	and promoting benefits of energy efficiency and value of more comprehensive upgrades and assessments. This is further supported through E1 website updates and marketing through various platforms. <u>Split incentive for rentals</u>: when either landlords or renters are not paying for utilities, they are often not motivated to implement energy efficiency upgrades. The split incentive barrier is addressed through availability of this service for both tenants and property owners. Regardless of who pays the utility bills, there are benefits (more efficient products installed at no-cost and lower utility bills) for both landlords and tenants. Oftentimes, higher efficiency products (such as LED bulbs) have longer lifetimes than their inefficient equivalents (i.e. incandescent bulbs). <u>Lack of trust</u>: some potential participants do not trust a free service; E1 markets the program through various platforms to provide confidence that the service is legitimate. This is further supported through E1 website updates. <u>Lack of information</u>: lack of knowledge about how to select and install energy efficient products. This is addressed through delivery agents and installers that provide customers with energy efficiency tips, information, and knowledge during home visits. E1 also leverages its website to provide education and tools to inform. This is further supported through marketing tactics delivered across several platforms.
	Mi'kmaw Home Energy Efficiency Project	Initial energy assessment of home to identify energy efficient upgrades; implementation of upgrades, including removal and responsible recycling of inefficient appliances and replacement with energy	Residential band-owned homes in Mi'kmaw communities	<u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments). This service addresses the affordability barrier providing assessments and upgrades by trained professionals of energy efficient equipment and products, and building envelope upgrades, at no-cost to participants. <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. This is addressed through assessments performed by Natural Resource Canada (NRCan) Registered Energy Advisors (EAs), who educate and inform customers on upgrades. This is further supported through E1 website updates and marketing through various platforms. <u>Resources</u>: lack of time/human resources for project management, contractor management, and upgrade implementation. E1's delivery agents provide complete project management from start-to-finish, reducing the resources barrier. <u>Split Incentive</u>: without incorporating benefits for band offices and participants, Housing Managers often face competing priorities and limited financial resources to

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
EXISTING RESIDENTIAL	Mi'kmaw Home Energy Efficiency Project	efficient appliances; Final energy assessment.		implement energy efficiency upgrades to the building and/or equipment. Regardless of who pays the utility bills, there are benefits (more efficient equipment and building envelopes, installed at no-cost, and lower utility bills) for both Housing Managers and participants. Oftentimes, upgrades contribute to improved overall comfort and performance of band-owned housing stock, providing benefits for participants.
	Green Heat	Post-purchase rebates on heat pumps, biomass space heating equipment, solar thermal space and water heating.	Property owners of residential dwellings in Nova Scotia, including single detached homes, semi-detached homes/duplexes, townhouses, mobile/mini homes, and condominiums.	<u>Affordability</u>: lack of financial resources to cover costs (product/equipment, installation). This is addressed through the availability of post-purchase rebates that are easy-to-access through several means (i.e. mail, electronic mail, fax, and online). <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. E1 works directly with residential heating distributors and retailers to promote and market the benefits of efficient space and water heating equipment. This is further supported through E1 website updates and marketing through various platforms. <u>Short decision period</u>: replacement of failing space or water heating equipment can occur quickly resulting in lost opportunities if the efficient product is not purchased. In the absence of easily accessible rebates to discount the upfront cost of efficient equipment, consumers are likely to choose inefficient alternatives. This is addressed through marketing and promotional activities to drive awareness of Green Heat rebates, as well as readily available rebate application options. E1 encourages retailers of biomass space heating equipment to participate and provides promotional materials to retailers for display in-store, at or near the efficient equipment option.
	Home Energy Assessment	Customized assessments that provide tailored recommendations for energy efficient upgrades and access to rebates or financing.	Property owners of residential dwellings in Nova Scotia, including single detached homes, semi-detached homes/duplexes, townhouses, mobile/mini homes, and condominiums.	<u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments). Rebates, and access to financing options, reduce the upfront cost of upgrades and address the barrier of high upfront costs. For eligible measures, rebates are stackable with the Federal Greener Homes grant, providing ample financial support for homeowners conducting several whole-home energy efficient upgrades. <u>Awareness & lack of understanding</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. Homeowners may also struggle to find qualified contractors to perform energy efficiency upgrades and/or be unsure about how to move forward and have upgrades completed. This is addressed through assessments performed by NRCan Registered EAs, who educate and inform

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
EXISTING RESIDENTIAL	Home Energy Assessment			customers on upgrades. This is further supported through E1 website updates providing access to tools and guides to navigate the program and eligible measures, as well as through access to the Efficiency Preferred Partner (EPP) network, and marketing through various platforms. <u>Short decision period</u>: replacement of failing space or water heating equipment can occur quickly resulting in lost opportunities if the efficient product is not purchased. In the absence of easily accessible rebates to discount the upfront cost of efficient equipment, consumers are likely to choose inefficient alternatives. This is addressed through marketing and promotional activities to drive awareness of Home Energy Assessment rebates, as well as through online tools and guides, such as the Rebate Guide. <u>Uncertainty</u>: homeowners may be reluctant to enroll if they do not understand the costs, benefits, and appropriateness of efficiency measures for their home specifically. This is addressed through assessments performed by NRCAN Registered EAs, who educate and inform customers on upgrades, and through customized reports following the initial assessment, which provides upgrade recommendations tailored to the home. This is further supported through E1 website updates and marketing through various platforms.
	Affordable Single-family Homes	Initial energy assessment of home to identify energy efficient upgrades; implementation of upgrades, including removal and responsible	Income-qualified (Statistics Canada Low-Income Cut-Off [LICO] threshold ¹) residential homeowners. ²	<u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments). This service addresses the affordability barrier providing assessments and upgrades by trained professionals of energy efficient equipment and products, and building envelope upgrades, at no-cost to participants. <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. This is addressed through assessments performed by NRCAN Registered EAs, who educate and inform customers on upgrades, as well as the fully project-managed delivery model. This is further supported through E1 website updates and marketing through various platforms.

¹ Statistics Canada. Table 11-10-0241-01 Low-income cut-offs (LICOs) before and after tax by community size and family size, in current dollars.
<https://www150.statcan.gc.ca/n1/en/catalogue/11100241>

² LICO is regularly updated by Statistics Canada

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
EXISTING RESIDENTIAL	Affordable Single-family Homes	recycling of inefficient appliances and replacement with energy efficient appliances; Final energy assessment.		<u>Resources</u>: lack of time/human resources for project management, contractor management, and upgrade implementation. E1's delivery agents provide complete project management from start-to-finish, reducing the resources barrier. <u>Lack of trust</u>: some potential participants do not trust a free service; E1 markets the program to provide confidence that the service is legitimate. This is further supported through E1 website updates and marketing through various platforms. <u>Lack of information</u>: lack of familiarity with energy efficient products. This is addressed throughout the participant's journey in the program through NRCan Registered EAs that engage directly with customers during home visits, discussing potential home upgrades, and promoting benefits of energy efficiency and value of the comprehensive upgrades available in the service.
	Residential Behaviour	The Residential Behaviour program component plans to provide tools and insights that will encourage Nova Scotians to adopt more energy-conscious behaviours and activities, leading to electricity savings and reduced utility bills.	All residential customers who require assistance to make the best decisions around energy-use for their homes, including renters and owners.	<u>Awareness</u>: lack of personal, relevant, and actionable insights about energy saving behaviours, products, and programs. The Residential Behaviour component addresses this barrier through personalized and timely energy-use feedback to assist residential customers in making informed choices about their energy consumption behaviours. By promoting benefits of energy efficiency, the value of more comprehensive upgrades, and ensuring awareness of E1 programs and services, can help customers change their energy behaviours. <u>Accessibility</u>: some potential participants may be unsure of the types of products or services available to reduce energy consumption, and how to get started. This is addressed through cross-promotion and marketing efforts delivered along with energy use feedback. <u>Short decision period</u>: in the absence of timely and personalized insights, potential participants may replace failing equipment without considering the efficient alternative. In the absence of timely insights, residential customers may be unaware of the efficient product and equipment options available through E1 programs and services. This is address through personalized, actionable insights available through energy use feedback such as, home energy reports and notifications. <u>Lack of information</u>: lack of familiarity, information, or knowledge about energy efficient technologies, upgrades, energy savings, and benefits. The program component offers education and tools to inform customers of their home's energy use addressed through regular, timely reports and notifications providing customers with

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
EXISTING RESIDENTIAL	Residential Behaviour			personalized insights on their energy consumption. This is further supported through E1 website updates and complemented by access to E1's Energy Solutions Advisor contact team for further advice, and program and service details.
NEW RESIDENTIAL	New Home Construction	For those building a new home: access to technical expertise and financial incentives for installing energy efficient upgrades during design and early construction phases.	Nova Scotia residents and builders who are building a new home in Nova Scotia.	<u>Affordability</u>: lack of financial resources to cover upfront costs of new home modelling and energy efficient upgrades. The New Residential program addresses this through financial incentives, based on pre- and post-construction modelling of the home and the performance of implemented upgrades. This is further supported through E1 website updates providing access to tools and guides to navigate the program and eligible measures, as well as through relationships with builders across the province. <u>Lack of information & competing interests</u>: builders or residents of prospective new construction homes may have a lack of familiarity with energy efficient upgrades and equipment. In addition, builders that are constructing homes on specifications may face competing interests between prioritizing energy efficiency and keeping purchase costs low for prospective buyers. This is addressed through NRCan Registered EAs that work with participants to provide tailored upgrade recommendations and educate on cost-effective energy efficient options. New home performance is rebated on a tiered incentives system, where rebates are higher with each succeeding level of higher energy efficiency and home performance. This is further supported through E1 website updates providing access to tools and guides to navigate the program and eligible measures, as well as through relationships with builders across the province.
DEMAND RESPONSE	Residential Demand Response (DR)	E1 will explore the implementation of up to five pathways for residential customers: battery control, behavioural DR, direct load control, enabling technologies	The target market is primarily residential customers, and can also include renters, diverse and underserved communities, landlords responsible for utility bills, and residential customers on dynamic (time-varying) rate structures.	<u>Awareness</u>: some potential participants may not understand the costs, benefits, and appropriateness of various projects for their residence. Residential DR plans to co-deliver some of the program pathways through energy efficiency (EE) programs. The awareness barrier is addressed through this potential integrated delivery option. This is further supported through E1 website updates, in-store promotional events and community outreach, and marketing through various platforms. <u>Resources</u>: some participants may not have the resources, such as time, human capital for project management, and capacity to hire contractors to implement upgrades. Addressed through integrated and/or co-delivery with EE programs and services, providing a fulsome participant journey. This is further supported through E1 website updates and marketing through various platforms.

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
DEMAND RESPONSE	Residential Demand Response (DR)	through CPP rates, and electric vehicle managed charging.		<u>Hassle factor</u> : DR can require customers to make choices that inconvenience them temporarily. This may include reduced comfort, reduced productivity, and products/services being unavailable during DR events. This is addressed by provision of enabling technologies that will make it easy for customers to respond to DR events or rates, educate customers around DR and effortless ways to participate in DR, and provide incentives that overcome the hassle barrier.

1

2 Table 2: Business, Non-Profit & Institutional (BNI) Barriers to Participation & Mitigating Strategies

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
CUSTOM INCENTIVES	Custom	Customized incentives for retrofits and new construction opportunities based on case specific energy and demand savings.	Open to eligible existing and new construction Nova Scotia business, non-profit, institutional, and industrial customers. Despite its broad customer eligibility criteria, the program component typically targets larger energy users.	<u>Upfront costs & internal competition for capital</u>: financial constraints resulting from internal competition for capital, in addition to the upfront cost requirement for feasibility studies and audits, before energy savings potential is known, can be challenging for companies to justify. This is addressed through financial incentives for initial scoping and feasibility studies to evaluate energy savings opportunities, and energy modelling of new building designs. This is further supported through rebates and financing for implementing cost-effective efficient projects. <u>Time & internal capacity constraints</u>: some companies may not have the internal capacity to consider energy efficiency options (e.g. identify, evaluate) in purchasing decisions. E1 staff, partners, and third parties identify, define, assess, and implement energy saving opportunities. <u>Lack of internal commitment & technical expertise</u>: in-house staff may be unfamiliar with new efficient technologies or processes. This is addressed through financial and/or technical assistance for improvements to compressed air systems, to optimize building performance, and to assess and implement energy management opportunities. E1 markets the program to provide education and tools to inform. This is further supported through marketing tactics delivered across several platforms, including support through Business Development Managers (BDMs) and Onsite Energy Managers (OEMs) made available to business verticals and organizations. <u>Payback periods</u>: companies often require short paybacks on investments making it challenging for custom energy efficiency projects to compete against other capital

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
CUSTOM INCENTIVES	Custom			investments. This is addressed through rebates and financing for implementing cost-effective efficient projects, which often result in shorter payback periods.
	Strategic Energy Management (SEM) & Energy Management Information Systems (EMIS)	Technical and financial support for the implementation of energy management policies and processes. Customized incentives for energy management information systems based on case specifics.	SEM is available to industrial customers across the province. The program component targets larger energy users, such as medium-to-large industrials, and has support for commercial/institutional customers through pilots. EMIS is available to industrial customers across the province. The EMIS program component typically targets larger energy users, such as medium-to-large industrials.	<u>Upfront costs & internal competition for capital</u>: financial constraints resulting from internal competition for capital, in addition to the upfront cost requirement for feasibility studies and audits (EMIS), or upfront cost requirements for SEM service provide support, before energy savings potential is known, can be challenging for companies to justify. For SEM, this is addressed through financial incentives, such as subsidized participation costs for SEM service provider facilitation. For EMIS, this is addressed through financial incentives for initial audit, energy management information system implementation plan and installation. <u>Lack of internal commitment & technical expertise</u>: in-house staff may be unfamiliar with new efficient technologies or processes. For EMIS, this is addressed through financial and/or technical assistance for improvements to compressed air systems, to optimize building performance, and to assess and implement energy management opportunities. E1 markets the program to provide education and tools to inform. This is further supported through marketing tactics delivered across several platforms, including support through BDMs and OEMs made available to business verticals and organizations. For SEM, E1 staff and the service provider help participants identify strategic energy management opportunities and establish continuous improvement policies and processes. <u>Payback periods</u>: companies often require short paybacks on investments making it challenging for custom energy efficiency projects to compete against other capital investments. This is addressed through financial incentives for implementing cost-effective efficient projects, which often result in shorter payback periods. <u>Time & internal capacity constraints</u>: some companies may not have the internal capacity to consider energy efficiency options (e.g. identify, evaluate) in purchasing decisions. For SEM, E1 staff and the service provider help participants identify strategic energy management opportunities and establish continuous improvement policies and processes. For EMIS, E1 staff, partners, and third parties identify, define, assess, and implement projects.

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
DIRECT INSTALLATION	Small Business Energy Solutions	Technical and financial support and incentives to small businesses for installation of energy efficient and demand reduction equipment.	The target market is primarily small commercial businesses, and can also include not-for-profits, multi-unit residential buildings and small industrials. The program is targeted to those small businesses with annual electrical energy consumption of 350,000 kWh or less.	<u>Affordability</u>: the cost of equipment/upgrades and lack of access to affordable capital can be a barrier to program participation. This is addressed through free energy audits to assess upgrade opportunities, prescriptive rebates through the self-serve pathway, and the direct installation pathway installing energy efficient measures at no-cost. <u>Awareness & resources</u>: some potential participants may not understand the costs, benefits, and appropriateness of various projects for their business. In addition, some participants may not have the resources, such as time, human capital for project management, and capacity to hire contractors to implement upgrades. This is addressed through support provided to customers by a Small Business Energy Auditor, including an energy audit, to identify upgrade opportunities, and customized measure incentives. This is further supported through E1 website updates and complemented by access to a dedicated Small Business Development Manager for further advice, technical support, and assistance navigating program and service details.
EFFICIENT PRODUCT REBATES	Business Energy Rebates	Financial incentives for installation of a variety of high efficiency equipment and demand reduction equipment (instant and mail-in rebates).	The target market includes all existing and new construction business, non-profit and institutional facilities, including multi-unit residential buildings.	<u>Upfront costs & project return</u>: the higher priced energy efficient equipment is a barrier for many customers, who often also face competing priorities for capital investments. This is addressed through easy-to-access rebates through both mail-in and instant streams, which reduce the upfront cost of energy efficient upgrades and equipment. <u>Lack of knowledge & technical expertise</u>: many customers are not familiar with high efficiency options. E1 leverages its relationships with distributors/partners to promote rebates and provide assistance and expertise in completing mail-in rebate applications. This is further supported through E1 website updates and complemented by access to a BDM for further advice, technical support, and assistance navigating program and service details. <u>Time & internal capacity constraints</u>: some businesses may not have the internal capacity to consider energy efficiency options (e.g. identify, evaluate) in purchasing decisions. E1 staff, partners, and distributors are available to help participants identify upgrade opportunities, complete applications, and navigate program offerings. This is further supported through E1 website updates providing access to tools and guides to navigate the program and eligible measures, as well as through access to the EPP network, and marketing through various platforms.

Program	Program Component	Description	Target Market Segment	Market and/or Participant Barriers and How they are Addressed in the Settlement Plan
DEMAND RESPONSE	BNI Demand Response	E1 will explore the implementation of up to four pathways available for BNI customers: battery control, curtailment, direct load control, and enabling technologies through CPP rates.	The target market is comprised of non-residential customers, and can also include diverse and underserved communities, landlords responsible for utility bills, and customers on dynamic (time-varying) rate structures.	<u>Awareness</u>: some potential participants may not understand the costs, benefits, and appropriateness of various projects for their residence. Residential DR plans to co-deliver some of the program pathways through EE programs. The awareness barrier is addressed through this potential integrated delivery option. This is further supported through E1 website updates, in-store promotional events and community outreach, and marketing through various platforms. <u>Resources</u>: some participants may not have the resources, such as time, human capital for project management, and capacity to hire contractors to implement upgrades. This is addressed through integrated and/or co-delivery with EE programs and services, providing a fulsome participant journey. This is further supported through E1 website updates and marketing through various platforms. <u>Hassle factor</u>: demand response can require customers to make choices that inconvenience them temporarily. This may include reduced comfort, reduced productivity, and products/services being unavailable during DR events. This is addressed by provision of enabling technologies that will make it easy for customers to respond to DR events or rates, educate customers around DR and easy ways to participate in DR, and provide incentives that overcome the hassle barrier.

Appendix A

2023-2025 DSM Resource Plan

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1. INTRODUCTION

EfficiencyOne's (E1) 2023-2025 Demand Side Management (DSM) Resource Plan (Settlement Plan) represents a meaningful and ambitious level of energy efficiency and greenhouse gas (GHG) emission reductions at a time when the climate emergency and transformational environmental policies are requiring greater investments in clean energy resources. The development of the Settlement Plan coincides with a pronounced focus by both the federal and provincial governments to achieve net zero emissions by 2050 and to accomplish this monumental transition in an equitable manner. Energy efficiency is widely recognized as a key pathway to accomplish these goals. Specifically, electric demand side management resources are a key strategy to support the further transformation of the electricity system to achieve higher levels of renewables, phase out coal generation, and manage impacts from electrification efforts in a manner that is affordable to customers.

E1 has developed the Settlement Plan to deliver cost-effective energy efficiency, system coincidence peak demand reduction, and demand response capacity resources through new initiatives and enhanced service offerings that provide both short- and long-term benefits to ratepayers.

The Settlement Plan has been developed based on E1's twelve-year experience and history in delivering successful DSM programs and services to Nova Scotians. This success is a result of strong partnerships, meaningful stakeholder engagement, and Nova Scotians' demand for assistance to make energy efficiency choices. Today, residents and businesses are collectively saving over \$130 million in annual electricity costs (accounting for DSM cost recovery)¹ and over 775 kilotonnes of greenhouse gas emissions annually through a variety of programs and services.

E1's Settlement Plan is an investment of \$173 million for both energy efficiency (EE) and demand response (DR) programming – an investment that saves customers money now and, in the future, reduces greenhouse gas emissions, increases DR capacity, and supports a robust local industry in Nova Scotia, dominated by small businesses.

¹ M10321, EfficiencyOne 2021 Rate and Bill Impact Analysis and Model (1 November 2021), Electronically filed model version, (Microsoft Excel file).

Over the past decade, demand side management in Nova Scotia has provided benefits (avoided cost to ratepayers) that far exceed the total utility investment by a magnitude of more than 4 to 1, on average. The \$173 million Settlement Plan investment will deliver lifetime benefits of \$543 million to Nova Scotians. While DSM is known for delivering long term savings to customers, its benefits begin immediately on day one of delivery. By the end of 2027, the DSM investment will have been recovered from avoided costs – less than a 5-year payback.

The Settlement Plan addresses the continued maturation of Nova Scotia's electricity efficiency market. Since 2010, the energy landscape has evolved for both E1 and Nova Scotians. Success in DSM program delivery has driven accelerated market penetration for some energy efficiency products, particularly in the residential lighting, heat pump, and new construction markets. As high lighting market penetration continues to diminish some of the lowest-cost opportunities, E1 must evolve its DSM portfolio to increase focus on more complex markets and projects – as a result, the historically low first year unit costs of DSM cannot be maintained. Despite the resulting increasing unit costs, the Settlement Plan remains cost effective and demand side management continues to be a smart investment that helps customers lower their energy bills, with an EE² Total Resource Cost (TRC) ratio of 2.0, an EE Program Administrator Cost (PAC) ratio of 3.3, and a DR TRC ratio of 1.1.

Consistent with previous DSM Resource Plans, E1 has taken a balanced approach in the design of its program portfolio. The Settlement Plan focuses on program enhancements that improve the customer experience, increase accessibility of programs for diverse and underserved communities, remove barriers to participation, support Federal and Provincial decarbonization goals, and achieve deeper³ savings from non-lighting measures.

The Settlement Plan outlines E1's proposed programs and strategies for achieving the energy and system-peak demand saving targets for 2023-2025. The purpose of the Settlement Plan is to:

- outline DSM targets, objectives, performance metrics, strategies, and investment levels for 2023-2025;

² Includes Enabling Strategies investment.

³ Deeper energy savings is defined as providing E1 support to enable customers to complete a wide range of energy efficiency upgrades/efforts, in order to help them maximize cost-effective energy savings per building/facility. In many cases, these efforts will take place over several years.

- provide a detailed description to stakeholders, customers, partners, and industries in the marketplace of the direction that E1 is taking demand side management programs for the next three years; and
- form the basis of a DSM Supply Agreement made pursuant to S79 of the *Public Utilities Act*⁴.

1.1 TODAY'S PLANNING LANDSCAPE

The planning landscape for electricity demand side resources is changing quickly in Nova Scotia, driven by factors such as progressing market transformation, emerging technologies, evolving customer expectations and climate change goals. To frame the planning landscape for consideration in the Settlement Plan, E1 identified the following influences, each of which is discussed in the sections that follow.

- 2020 Integrated Resource Plan (IRP) results;
- climate change goals;
- the global COVID-19 pandemic; and
- the transformation of the Nova Scotia market.

1.1.1 2020 INTEGRATED RESOURCE PLAN RESULTS

Since E1's 2020-2022 DSM Plan was developed and approved, NS Power conducted a new IRP which was used to inform the development of the Settlement Plan. NS Power's 2020 IRP reflected themes of decarbonization, as well as regional integration, and electrification. Demand side resource options were explored in the 2020 IRP through the incorporation of E1's four 2019 Potential Study DSM scenarios as a load modifier and E1's four 2019 Potential Study DR scenarios as a supply side resource option.

The IRP Reference Plan selected through the 2020 IRP process was Scenario 2.0C (Base DSM and Base DR), which results in the lowest net present value revenue requirement for ratepayers. This was the first time DR had been included in the IRP. The IRP Reference Plan calls for 2,896 GWh of first year energy savings and 81 MW of capacity from DR by 2045. Avoided costs of energy, capacity, and carbon were calculated using the 2020 IRP Reference Plan (2.0C) and a no-DSM (2.0C) comparator scenario for use in the development of the Settlement Plan. Avoided costs for transmission and distribution were not provided as part of the IRP process but were developed collaboratively with the Demand Side Management Advisory Group (DSMAG), including NS Power.

⁴ *Public Utilities Act*, RSNS 1989, c 380, s.79.

The 2020 IRP Action Plan proposed the initiation of an Electrification Strategy to develop options for encouraging beneficial electrification, inclusive of proposed pilots and programs subject to Nova Scotia Utility and Review Board (NSUARB) oversight. The IRP Action Plan also includes the creation of a Demand Response Strategy targeting 75 MW of deployable capacity by 2025. E1 looks forward to actively participating in these initiatives and has modelled a DR program in its Settlement Plan. However, given that the Electrification Strategy has not been developed, there is uncertainty around what future ratepayer funding may look like, and specific implications for demand side management activities. Although uncertainty remains, E1 anticipates that there will be a role for the organization in the support of the development and implementation of future beneficial electrification programs and as such has incorporated support for these initiatives as part of its Enabling Strategies component of the Settlement Plan.

1.1.2 LEGISLATED CLIMATE CHANGE GOALS

Climate change policy and goals are evolving quickly and have shifted even throughout the development of the Settlement Plan. In October and November 2021, the United Nations Climate Change Conference (COP26) signaled that nations the world over, are committed to limiting the global temperature rise to 1.5 degrees⁵ to avoid the most serious climate change impacts. In line with this commitment, our Federal and Provincial Governments have introduced recent environmental goals to achieve emissions reduction targets of net zero by 2050. Specifically, the Federal Government has announced the following environmental commitments⁶:

- cease all coal-fired electricity generation by 2030;
- increase the federal price of carbon by \$15/tonne beginning in 2023 and reaching a level of \$170/tonne by 2030; and
- achieve a net zero emissions electricity sector by 2035.

⁵ United Nations Climate Press Release, November 13, 2021. <https://unfccc.int/news/cop26-reaches-consensus-on-key-actions-to-address-climate-change>

⁶ Environment and Climate Change Canada, A Healthy Environment and a Healthy Economy, 2020. <https://www.canada.ca/en/environment-climate-change/news/2021/11/canada-and-the-world-move-closer-to-powering-past-coal-with-more-climate-ambition-at-cop26.html>

Provincially, the Nova Scotia government recently enacted Bill 57, the *Environmental Goals and Climate Change Reduction Act*. The Act sets out climate change goals and greenhouse gas emission targets⁷ including:

- by 2030, GHG emissions be at least 53% below the levels that were emitted in 2005;
- by 2050, GHG emissions be net zero, by balancing GHG emissions with GHG removals and other offsetting measures;
- have 80% of electricity in the province supplied by renewable energy by 2030;
- phase out coal-fired electricity generation in the province by the year 2030;
- support, strengthen, and set targets for energy efficiency programming while prioritizing equitable access and benefits for low income and marginalized Nova Scotians;
- require any new build or major retrofit in government buildings, including schools and hospitals, that enters the planning stage after 2022, to have net zero energy performance and be climate resilient;
- decrease GHG emissions across government-owned buildings by 75% by the year 2035; and
- develop and implement a zero-emission vehicle mandate that ensures, at a minimum, that 30% of new vehicle sales of all light duty and personal vehicles in the province will be zero-emission vehicles by 2030.

E1's Settlement Plan positions DSM to be an effective contributor to the clean energy transformation that is underway in helping Nova Scotia reach their climate change goals and doing so affordably. While the IRP Reference Plan's level of energy efficiency and avoided costs of DSM do not necessarily reflect the recent environmental goals of Bill 57, the IRP Evergreen Process that is currently being carried out, should incorporate the implications of these recent policy changes.

1.1.3 THE GLOBAL COVID-19 PANDEMIC

The onset of the global COVID-19 pandemic presented challenges and opportunities for delivering DSM activities in Nova Scotia. The pandemic impacted elements of E1's business operations throughout 2020 and 2021. It also offered an opportunity to reimagine aspects of service delivery and pilot modifications to existing programs. At the onset, the pandemic resulted in a high degree of uncertainty for future markets

⁷ Environmental Goals and Climate Change Reduction Act, SNS 2021, c.20

including the duration of the pandemic, longevity of short-run economic impacts on homes and businesses, supply chain delays, participation, and customer attitudes.

During 2020 and 2021, the COVID-19 pandemic slowed E1's progress toward achieving energy efficiency targets primarily as a result of lockdowns that limited certain activities such as in-home and in-business site visits, labour shortages, and supply chain issues creating project delays. At the same time, E1's need for innovative solutions resulted in exploration of different program delivery models such as virtual audits and assessments, targeting unoccupied buildings, and virtual education and outreach approaches. E1 also saw increased opportunities in addressing customer concerns with building air quality and ventilation issues as a result of the pandemic, which provides an opportunity to increase energy efficiency and reduce emissions while, at the same time, addressing health and comfort concerns.

Despite E1's swift response to the impacts caused by COVID-19, E1 fell short of its 2020 and 2021 DSM Plan targets, as filed. E1 has drawn upon the insights gathered from customers through the 2020 and 2021 COVID-19 impact period to inform E1's portfolio and key assumptions in the Settlement Plan. In the development of the Settlement Plan, E1 has assumed no further periods of isolation or shutdown, and that current labour shortages and supply chain issues will be largely resolved by the end of 2023.

As the province of Nova Scotia continues to respond to the uncertainty caused by the COVID-19 pandemic and its effect on Nova Scotia's economy, E1 can help support the recovery through energy efficiency. Not only does energy efficiency lower energy costs for customers but investing in DSM programs also means investing in the local economy, creating jobs in a variety of areas including energy management and modelling, building design, and the professional trades. Through E1's Efficiency Preferred Partner (EPP) network, there are over 260 local businesses enrolled to help Nova Scotians with their energy efficient improvements. These businesses are located across the province and can provide a boost to local economies in both rural and urban settings.

1.1.4 TRANSFORMATION OF THE NOVA SCOTIA MARKET

Within the changing energy industry, E1 faces an increasingly complex DSM planning environment as the Nova Scotia market matures and transforms, particularly in the residential sector. The residential lighting, heat pump, and new construction markets have achieved increasing energy efficiency transformation. Having delivered energy efficiency and conservation services in Nova Scotia for over a decade, E1, like other

DSM administrators, is encountering more complex and dynamic demand side resource opportunities to deliver value to customers. To address current levels of market transformation and continue to encourage further transformation in the energy efficiency marketplace, E1's 2023-2025 DSM portfolio reflects evolving opportunities through the re-introduction of a residential behaviour and whole home low-income programs, further diversification beyond lighting measures through expansion of more complex retrofit projects, and the development of a residential new construction market transformation program through Enabling Strategies.

1.2 DEMAND SIDE MANAGEMENT IN NOVA SCOTIA

1.2.1 OVERVIEW

The Settlement Plan delivers demand side resources to Nova Scotia ratepayers in support of achieving NS Power's long-term electricity strategy as provided in the IRP. The Settlement Plan offers a portfolio of DSM services that will be delivered to Nova Scotians over the three-year plan period and the investment required to do so. The portfolio of services is designed with a focus on cost-effectiveness, accessibility and equity, and affordability. To ensure programs are accessible for all ratepayers, E1 incorporates several marketing approaches, delivery methods, and program types to effectively remove barriers to participation. The Settlement Plan is also developed with both short- and long-term affordability in mind. E1 must also demonstrate how the investment in DSM balances the short-term and long-term benefits to ratepayers. The level of DSM, and the avoided costs resulting from NS Power's IRP, E1's Rate and Bill Impact Analysis (RBIA), and the program-level cost effectiveness testing (CET) results provide a framework to consider the affordability of the DSM Plan.

Historically, E1 has successfully delivered energy efficiency focused demand side management. For the first time, in its 2020-2022 DSM Resource Plan, E1 developed and subsequently implemented, peak demand reduction focused initiatives and measures, such as electric thermal storage units and building optimization incentives, for peak period demand reductions. In the 2023-2025 DSM Plan period, E1 will further expand the scope of demand side management resources available to Nova Scotians – incorporating capacity-focused initiatives (demand response).

Energy efficiency and demand response efforts engage customers and help to lower their energy costs, build industry capacity, support the local economy, and foster relationships with stakeholders, partners, and customers. Demand side management also improves conditions for local businesses, both large and

small, by enabling opportunities to lower the cost of operations, upfront costs of upgrading to efficient products and equipment, and helps to create and maintain local jobs. Capacity-focused initiatives such as demand response provide additional value to ratepayers through better understanding and control over their peak demand costs and usage, as well as increasing the capacity of flexible resources on the electricity grid to better respond to and plan for system peaks and smooth the integration of renewables.

1.2.2 OBJECTIVES OF THE 2023-2025 DSM RESOURCE PLAN

There are three main objectives of the Settlement Plan:

1. deliver cost-effective demand side resources that support the successful implementation of a long-term electricity strategy that is in the best interest of Nova Scotia ratepayers, supports Federal and Provincial climate change goals, and maintains affordability for Nova Scotians;
2. deliver a portfolio of demand side management services that are accessible on an equitable and non-discriminatory basis, are responsive to the current market, and proactively consider potential future market developments; and
3. conduct a transparent and collaborative demand side resource planning process that reflects best practice, demonstrates consideration of stakeholder insight, and encourages agreement among DSMAG members.

1.3 THE NEXT DECADE OF DSM

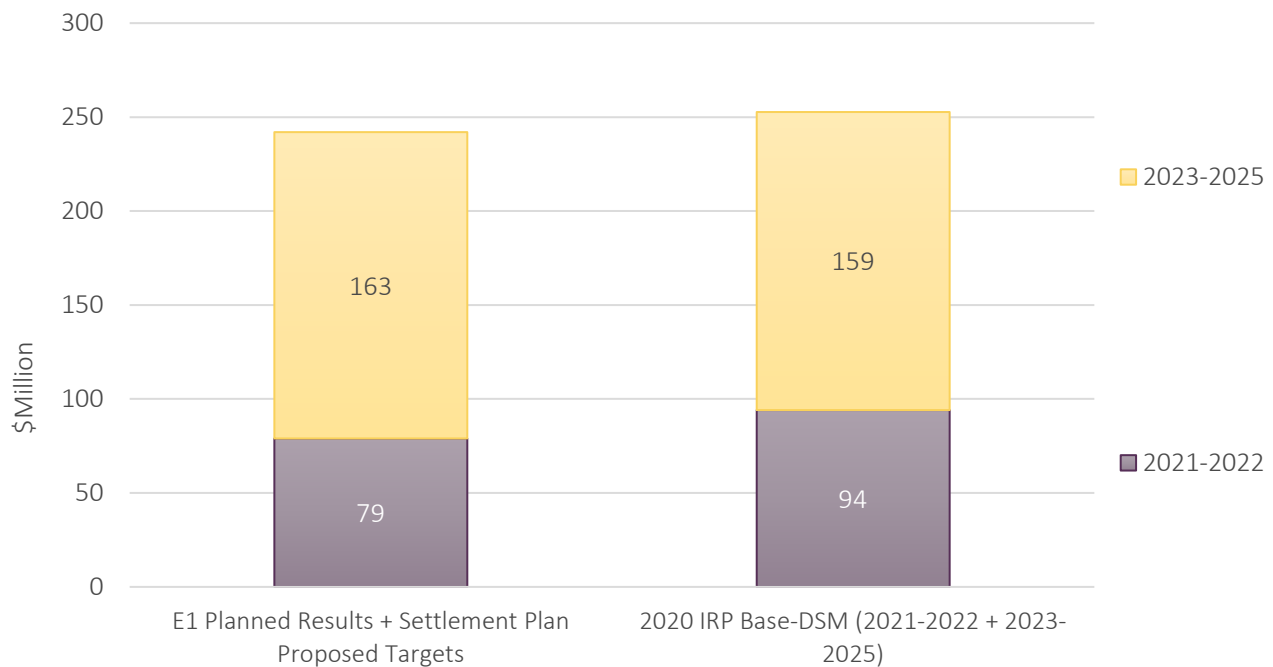
Nova Scotians have been achieving considerable energy, cost, and emissions savings through energy efficiency over the past ten years. But the current climate outlook requires further transition to clean energy resources, and this requires considerably more action in the next ten years.

E1 is facing an increasingly complex DSM planning landscape as the Nova Scotia market matures and continues to experience increasing transformation, particularly in the residential sector. Emerging topics like demand response, distributed energy resources, and advanced metering infrastructure offer an expanded range of demand side options to explore and consider in future DSM Plan portfolios. Our customers are changing too. More customers are working from home, have flexible work schedules, and want to engage with energy experts in convenient and virtual ways.

At a minimum, the 2020 IRP calls for over 2,800 GWh of efficiency to be delivered to the electricity grid by 2045 and we are already lagging because of COVID-19 impacts in 2020 and 2021. The Settlement Plan aims

at making up this lost ground to ensure that ratepayers do not lose out on realizing the benefits. Figure 1, below, compares energy efficiency results at the end of 2025 under the Settlement Plan to the 2020 IRP Reference Plan requirements.

Figure 1: 2021-2025 Energy Efficiency Investment (Settlement Plan) compared to 2020 IRP Reference Plan



2021 tracked results and 2022 planned targets and spending were used for E1 Planned Results.

The Settlement Plan continues to build on E1's historic foundation of success in DSM program delivery over the last decade and is transitioning to the level of DSM that is required in the future. The focus is on supporting industry capacity, helping Nova Scotia residents and businesses recover from the pandemic, and advance energy efficiency and climate change goals.

1.3.1 KEY ENHANCEMENTS & NEW DEVELOPMENTS IN 2023-2025

In the development of the Settlement Plan, E1 consulted external subject matter experts and leveraged internal expertise from having delivered energy efficiency programs since 2010 to assist with determining innovative solutions to challenges resulting from market saturation, overcoming barriers to participation in existing services, and to capitalize on opportunities for new initiatives or measures. Over the spring and summer of 2021, DSM Planning Teams comprised of internal cross-functional technical and program delivery expertise worked through the design of initiatives to address emerging areas of opportunity, challenges, and gaps in existing portfolio components. The Settlement Plan includes several new initiatives

and enhancements to existing programs and services, as described in Table 1, below, and further described in the referenced sections.

Table 1: New Initiatives and Key Enhancements in the 2023-2025 Settlement Plan

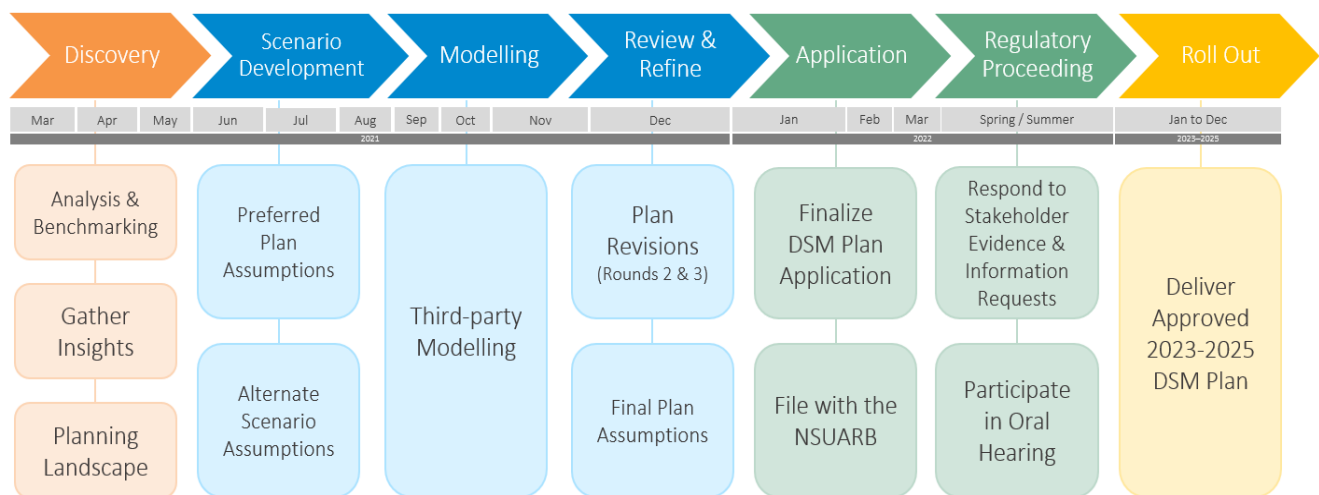
Title	Type of Initiative	Section Reference
Residential		
Affordable Single-family Homes	New program component in the residential sector	Section 4.2.2.6
Point-of-Sale Rebates for ENERGY STAR® Measures	Enhancement to existing Instant Savings program component	Section 4.1.2.2
Residential Behaviour	New program component in the residential sector	Section 4.2.2.7
Prescriptive Rebate Stream in Affordable Multi-family Housing	Enhancement to existing Affordable Multi-family Housing program component	Section 4.2.2.1
Electrician-Installed Measures	Enhancement to existing Efficient Product Installation program component	Section 4.2.2.2
Business, Non-Profit & Institutional (BNI)		
Midstream Commercial Kitchen	Enhancement to the BNI Efficient Product Rebates program	Section 5.1.2.1
Pay-for-Performance	Enhancement to existing Custom program component	Section 5.2.2.1
Commercial Direct Installation (SBES)	Enhancement to existing Direct Installation program	Section 5.3.2.1
Cross-Sector Initiatives (Residential & BNI)		
Demand Response Program	New program with two program components	Section 6
Market Transformation	New initiatives under Enabling Strategies	Section 7.2.3.5 & 7.3.3.5
Beneficial Electrification	New initiatives under Enabling Strategies	Section 7.3.3.3
Diverse & Underserved Communities	New initiatives under Enabling Strategies	Section 7.2.3.2
Innovation & Emerging Technologies	New initiatives under Enabling Strategies	Section 7.3.3.1

Each of these new initiatives and key enhancements are described in detail within the Enhancements sections of the Residential and BNI Programs & Services, Demand Response Programs & Services, and the Enabling Strategies sections of this document. Please refer to the Section Reference column in Table 1, above, for specific references to the report sections containing enhancement details.

2. DEVELOPMENT APPROACH & DETAILS

The Settlement Plan was developed for the purpose of delivering cost-effective energy and system-peak demand savings to Nova Scotia electricity ratepayers for the three-year plan period. E1 used a multi-phase development process to establish the appropriate level of energy and demand savings, the level of investment required to deliver on the savings targets, and how to best design a cost-effective portfolio of programs. Emphasis was placed on determining performance targets that met the electricity system needs, ensuring those targets were reasonable and achievable, and the portfolio design to deliver these savings was aligned with the NSUARB-approved balanced plan approach. The development of the Settlement Plan, as illustrated in Figure 2, was supported by E1's consultant Guidehouse, partnering with Energy Futures Group.

Figure 2: Development Process for the 2023-2025 Settlement Plan



The five phases in the development of E1's Settlement Plan, included:

- Discovery Phase – E1 defined the current planning landscape, identifying and detailing the key influences, draft guiding principles, and draft strategic themes guiding the plan development. Feedback on this was solicited from the DSMAG.
- Scenario Development Phase – this phase defined the draft DSM portfolios that were to be explored through modelling for the purposes of informing E1's Preferred Plan and Alternate Scenario. E1 proposed that up to five (5) scenarios would be modelled and provided three (3) initial scenarios to the DSMAG for consideration. DSMAG members were also provided an opportunity to provide feedback on not only the number of scenarios proposed but also suggestions for any

additional scenarios. NS Power also had the opportunity to request scenarios E1 could model on their behalf. For each DSM scenario, E1 included assumptions for DSM components, programs & services, target markets and performance impacts, which were circulated to the DSMAG. The comments and feedback received from the DSMAG helped inform the scenario parameters used in the next phase of the process, Modelling.

- Modelling Phase – during this phase, E1 identified the high-level assumptions for each scenario that would be modelled initially. For subsequent model runs, new scenarios were either added or existing ones were amended or eliminated.
- Review & Refine Phase – during this phase, E1 worked to incorporate feedback received from all stakeholders, refine the modelling input assumptions, and conduct re-modelling leading to final model outputs that would inform the Preferred Plan and Alternate Scenario. During this phase E1, NS Power, and the rate class advocates continued to have productive discussions and E1 was able to reach alignment with NS Power on a final DSM Plan for the 2023-2025 DSM Plan Application, referred to as the Settlement Plan.
- Application Phase – final selection of E1's Settlement Plan and Alternate Scenario completed.

Some of the Phases of DSM Plan development overlapped, for example Scenario Development and Modelling, coincided with the three rounds of energy efficiency and demand response modelling.

2.1 STAKEHOLDER ENGAGEMENT IN THE DEVELOPMENT PROCESS

In developing the Settlement Plan, E1 leveraged lessons learned from the 2020-2022 DSM Plan to enhance the development process and demonstrate responsiveness to stakeholder feedback. What E1 heard from its regulatory stakeholders coming out of the 2020-2022 DSM Plan process is that they wanted to be engaged in the development process earlier, specifically in relation to the DSM scenarios that would be examined through modelling. E1 has made a concerted effort to increase meaningful stakeholder engagement with the members of the DSMAG throughout the development process of the Settlement Plan through enhanced advance materials including early modelling results and supporting data, technical DSMAG sessions, one-on-one stakeholder meetings, and opportunities for written stakeholder feedback as highlighted in the sections that follow.

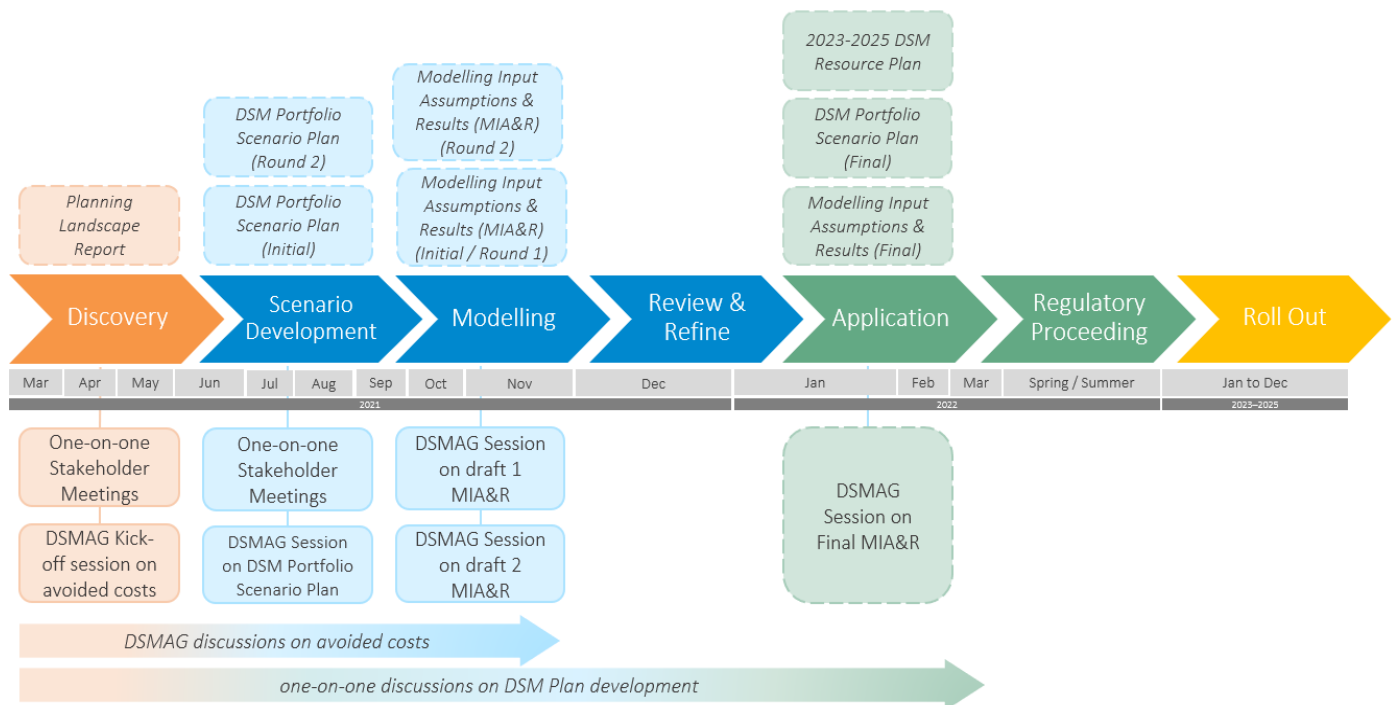
To ensure E1 fulfilled its commitment to stakeholder feedback from the previous DSM development process, E1 implemented a comprehensive stakeholder engagement plan which included meeting with key

external stakeholders, engaging internal subject matter experts as well as stakeholder engagement surveys with contractors, installers, retailers, service providers, and the public. This comprehensive approach allowed E1 to be proactive in engaging with stakeholders earlier in the process that allowed E1 to leverage stakeholders' areas of expertise into the development of the DSM Plan. E1 fostered transparency with stakeholders throughout the DSM Plan process through open dialogue with various stakeholders, collecting feedback, and responding to stakeholder inquiries to ensure there were no surprises in E1's final filing.

2.1.1 DSM ADVISORY GROUP STAKEHOLDER ENGAGEMENT

E1's engagement process sought to provide an accessible, equitable and affordable plan that was responsive to the current planning landscape. As illustrated in Figure 3, below, E1 implemented an extensive engagement process for the DSMAG using a series of phases, ultimately resulting in alignment with NS Power on the Settlement Plan. The DSMAG members include the Consumer Advocate (CA), Small Business Advocate (SBA), Synapse Energy Economics (consultant to the NSUARB), NS Power, Industrial Group (IG), Province of Nova Scotia, Assembly of Mi'kmaw Chiefs, Affordable Energy Coalition (AEC), Ecology Action Centre (EAC), the Municipal Electric Utilities (MEU), and Halifax Regional Municipality (HRM).

Figure 3: DSM Advisory Group Engagement



1 The timelines in E1's DSMAG stakeholder engagement process is outlined in Table 2, below.

2

3 Table 2: DSMAG Stakeholder Engagement Timelines in the 2023-2025 Settlement Plan Development

First Quarter of 2021	
Kick-off meetings with stakeholders, including: • NS Power • Consumer Advocate	March 24 to April 16
• Small Business Advocate • Industrial Group • Nova Scotia Department of Natural Resources & Renewable (DNRR)	March 24 to April 16
Second Quarter of 2021	
Stakeholder Engagement Plan circulated to the DSMAG	June 11
Planning Landscape Report circulated to the DSMAG for comment	June 17
Third Quarter of 2021	
Planning Landscape Report comment period closed; written comments submitted by: • CA (Green Energy Economics Group) • SBA • NS Power	July 2
Draft DSM Portfolio Scenarios Plan circulated to the DSMAG for comment	August 13
DSMAG Session: Draft DSM Portfolio Scenarios Plan	August 19
Draft DSM Portfolio Scenarios Plan comment period closed; written comments submitted by: • Synapse Energy Economics (Synapse) • NS Power • CA • Affordable Energy Coalition	September 2
One-on-one meetings with stakeholders, including: • NS Power • CA • SBA • Synapse	September 23 & 24
Updated DSM Portfolio Scenarios & Initial Model Results Package circulated to the DSMAG for comment; package comprised of: • Updated DSM Portfolio Scenarios Plan • Initial Model Input Assumptions & Results • Attachment A: Stakeholder Feedback Matrix	September 29

Fourth Quarter of 2021	
DSMAG Session: Updated DSM Portfolio Scenarios & Initial Model Results	October 5
Updated DSM Portfolio Scenarios & Initial Model Results Package comment period closed; written comments submitted by: • Synapse • CA • IG, informally (i.e. via email)	October 18
One-on-one meetings with stakeholders, including: • NS Power • CA • SBA	November 23
Updated DSM Portfolio Scenarios & Round 2 Model Results Package circulated to the DSMAG for comment; package comprised of: • Updated DSM Portfolio Scenarios Plan • Round 2 Model Input Assumptions & Results • Attachment A: Stakeholder Feedback Matrix • Attachment B: Avoided Costs Brief • Attachment C: Estimation of DSM Low-Income Impacts for the 2023-2025 DSM Resource Plan • Attachment D: Keeping the Lights On: Navigating the Changing Landscape of Retail Lighting • Attachment E: Scenario 1B (Mid-DSM) Round 2 Technical Tables • Attachment F: Scenario 1.5B (Base-Plus DSM) Round 2 Technical Tables • Attachment G: Scenario 2B (Base-DSM) Round 2 Technical Tables • Attachment H: Scenario 4B (Low-DSM) Round 2 Technical Tables • Attachment I: Demand Response (DR-B) Round 2 Model Inputs • Attachment J: Demand Response (DR-B) Round 2 Model Results • Attachment K: Rate and Bill Impact Analysis (RBIA) Scenario Summary	November 25
DSMAG Session: Updated DSM Portfolio Scenarios & Round 2 Model Results	November 29
Updated DSM Portfolio Scenarios & Initial Model Results Package comment period closed; written comments submitted by: • NS Power • CA (Green Energy Economics Group) • Synapse • Municipal Electric Utilities via AI Dominie • AEC	December 31
First Quarter of 2022	
One-on-one meetings with stakeholders, including: • NS Power • CA	January 17 to February 4

First Quarter of 2022	
• SBA • Synapse • AEC • Ecology Action Centre	January 17 to February 4
DSM Portfolio Scenarios & Round 3 Model Results Package circulated to the DSMAG; package comprised of: • DSM Portfolio Scenarios Plan • Round 3 (Preferred Plan & Alternate Scenario) Model Input Assumptions & Results • Attachment A: Stakeholder Feedback Matrix • Attachment B: Preferred Plan Technical Tables • Attachment C: Alternate Scenario Technical Tables	February 14
DSMAG Session: Presentation of E1's Preferred Plan and Alternate Scenario	February 17
Discussions with NS Power to consider alignment on the Settlement Plan. Engaged rate class advocates as part of the discussions.	February 17 to March 4

2.1.2 OTHER EXTERNAL STAKEHOLDER ENGAGEMENT

E1 conducted stakeholder engagement on the 2023-2025 DSM Plan with a variety of other external stakeholder groups, illustrated in Figure 4, below.

Figure 4: Other Stakeholder Groups that E1 engaged in the DSM Plan Development

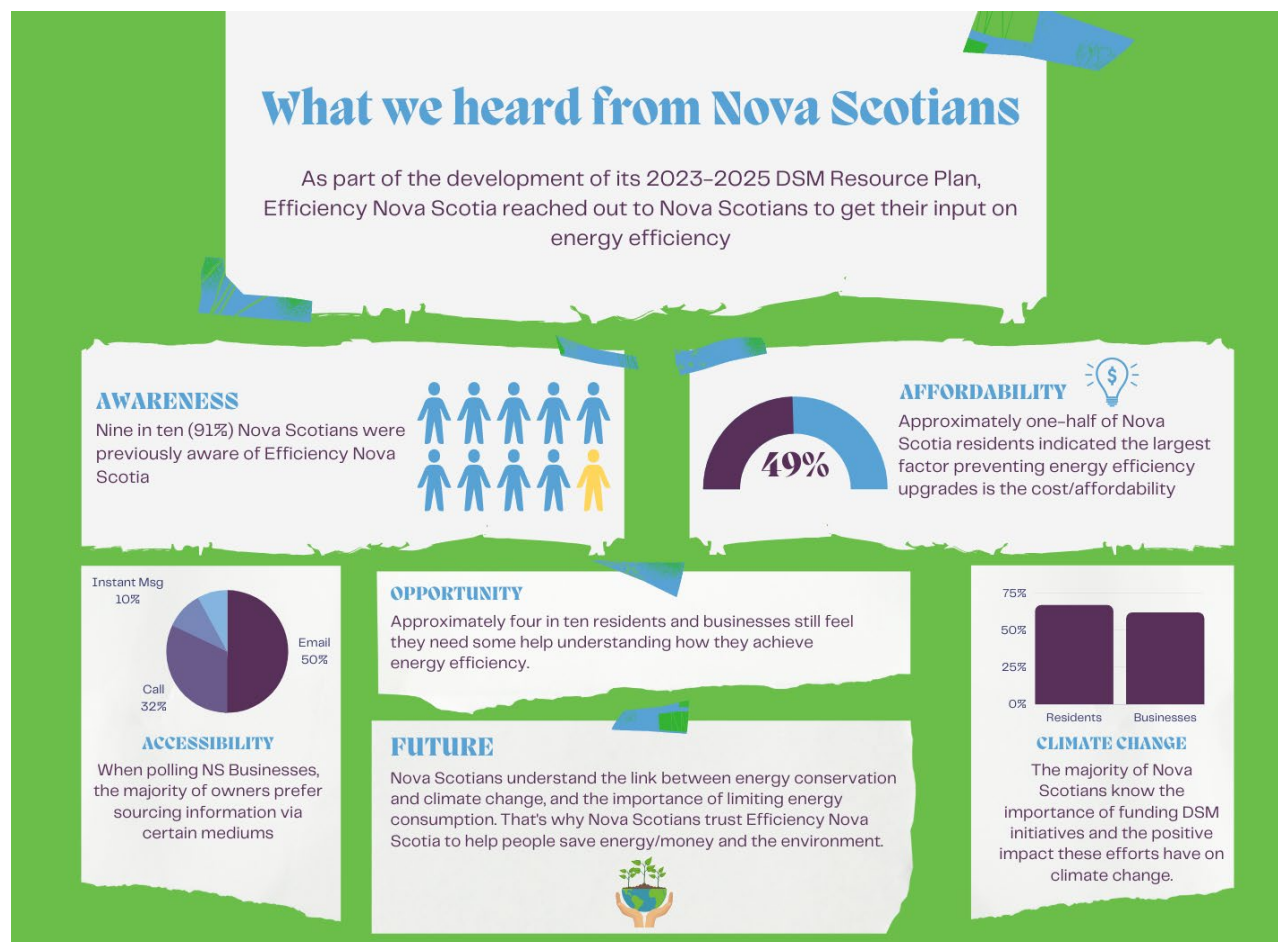


2.1.3 CUSTOMER INSIGHTS

As part of the development of its Settlement Plan, E1 commissioned Narrative Research to undertake a quantitative research study to assess perceptions on a variety of topics related to energy efficiency and

conservation among both residents and business organizations in the province. This research was conducted through an initial email invitation containing a unique survey link to a random sample of NS Power ratepayers in all rate classes, in addition to two email reminders, forwarded to sampled ratepayers. This sampling method yielded 1,535 usable residential, and 373 usable commercial survey responses. In addition, E1 posted a generic online survey link on its social media accounts, website, and through advertisements, to ensure all Nova Scotians had the opportunity to participate in this important research. The generic survey link yielded an additional 1,896 useable survey responses. An analysis of the survey responses provided significant insights for consideration in the 2023-2025 Settlement Plan development. Figure 5 highlights some of the key findings from the 2021 DSM Report.

Figure 5: Infographic – What We Heard from Nova Scotians



Through this research, it was found that the vast majority of Nova Scotians were previously aware of the Efficiency Nova Scotia brand and its commitment to helping residents and businesses reduce their energy use through services and programs. However, there is room to enhance awareness and uptake of E1's

Energy Solutions Advisor services as only one-third (35%) of residents and four in ten (43%) organizations have contacted an Energy Solutions Advisor in the past⁸. When surveyed, most participants preferred to contact E1 via email over phone conversations, instant messaging, and word of mouth. This indicated that Nova Scotians desire virtual access to efficiency experts and having accessibility to these experts. While awareness is a key component to E1 and its offerings, there is still opportunity to educate Nova Scotians on how they can achieve energy efficiency in their homes and businesses. This finding highlights the importance of education and outreach, which E1 supports through its Enabling Strategies, described in Section 7.

One of the largest barriers to participation that Nova Scotians indicated was the cost of upgrades. E1's Settlement Plan portfolio aims to help customers overcome these financial barriers.

A resounding theme that came out of the survey found that the majority of Nova Scotians know the importance of funding DSM initiatives and the positive impact that it can have not only on climate change but on encouraging behaviour change that reduces energy consumption. This indicates that Nova Scotians understand the link between energy conservation and climate action.

2.1.4 INTERNAL SUBJECT MATTER EXPERTS

E1's internal subject matter experts (SMEs) have frequent communication with customers, partners and other market actors and provide significant knowledge into current market conditions and trends. The engagement with internal subject matter experts was conducted throughout all phases of the DSM Plan development process, similar to E1's approach with external stakeholders.

This process allowed E1's SMEs to provide insight on current program assumptions, changes, trends and future influences during early planning when model characterizations were being developed. SMEs insights on each phase of model results supported the refinement of model inputs to shape the final portfolio and help ensure the Settlement Plan is deliverable and achievable.

⁸ Narrative Research 2021 DSM Report, Prepared for EfficiencyOne, January 2022, page 12, page 35.

2.2 KEY CONSIDERATIONS

2.2.1 GUIDING PRINCIPLES & STRATEGIC GOALS

E1 developed guiding principles and strategic themes to support the development of the Settlement Plan. The guiding principles, as shown in Figure 6, are related to vision and values. They reflect the “how and why” of the Settlement Plan, more than the “what.” Guiding principles are foundational and less subject to change based on emerging issues or market circumstances.

Figure 6: Guiding Principles in the Development of the 2023-2025 Settlement Plan

GUIDING PRINCIPLES

Transparency – E1 will provide stakeholders and customers with information and insight into the analyses supporting plan development and results and demonstrate how received comments were considered.

Accessibility & Equity – E1 services are accessible on an equitable and non-discriminatory basis and, where necessary, E1 targets hard to reach or potentially underserved market segments.

Affordability – E1’s portfolio aims to maximize value to electricity ratepayers, using the Integrated Resource Plan, the Rate and Bill Impact Analysis, and cost effectiveness testing as a framework to consider both short- and long-term affordability.

The strategic themes, as provided in Figure 7, identify elements which will inform the portfolio design and initiatives for the next plan cycle. They are the “what” of the Settlement Plan. These themes are variable, and change based on emerging topics and/or market circumstances.

Figure 7: Strategic Themes in the Development of the 2023-2025 Settlement Plan

STRATEGIC THEMES

The 2020 IRP Reference Plan – demand side resources are planned in support of the successful implementation of a long-term electricity strategy for delivery of safe, reliable, affordable, and clean electricity that is in the best interest of ratepayers.

Mitigate Climate Change – E1’s DSM portfolio is an important component of provincial strategies for decarbonizing Nova Scotia’s economy.

Effective Portfolio Design – the DSM portfolio of services is responsive to the market evolution that has occurred in Nova Scotia and reflects the current planning landscape.

The evidence used to inform the development of the Guiding Principles and Strategic Themes relied on several sources including but not limited to:

- results of NS Power’s 2020 IRP process;

- past NSUARB decisions;
- historical results and approved DSM Resource Plans;
- previous evaluation and verification results and their recommendations;
- expert consultation for strategic and modelling support;
- the Standardized Filing Framework's DSM Standards;
- stakeholder engagement and feedback;
- market conditions, industry research, and jurisdictional trends; and
- operational data and insights from internal subject matter expertise.

The Settlement Plan seeks to increase the overall utility avoided costs for the benefit of customers. NS Power's 2020 IRP identified the candidate resource plan (the Reference Plan) that results in the lowest revenue requirement from customers. The level of DSM investment and savings in the 2020 IRP Reference Plan is the base-level of DSM (for both energy efficiency and demand response) from Navigant's DSM Potential Study⁹. This level of energy and capacity savings informed the development of the Settlement Plan.

E1's Settlement Plan aligns, rather than continues to move away from, the achievement of savings in the IRP's Reference Plan. These annual savings represent the greatest long-term benefits to Nova Scotians and the Settlement Plan is helping provide customers a reasonable opportunity of realizing these benefits in the future by taking a responsible step in the right direction.

Determining a reasonable level of DSM for E1's Settlement Plan considers several factors including historical levels of energy savings E1 has achieved, whether there is sufficient industry capacity to support this level, and affordability. E1's Settlement Plan represents a ramp up from 2022 that has incorporated these factors.

Appropriate portfolio design is critical to effectively, responsibly, and equitably deliver cost-effective electricity savings levels established in E1's Settlement Plan. DSM portfolios must be responsive to evolving

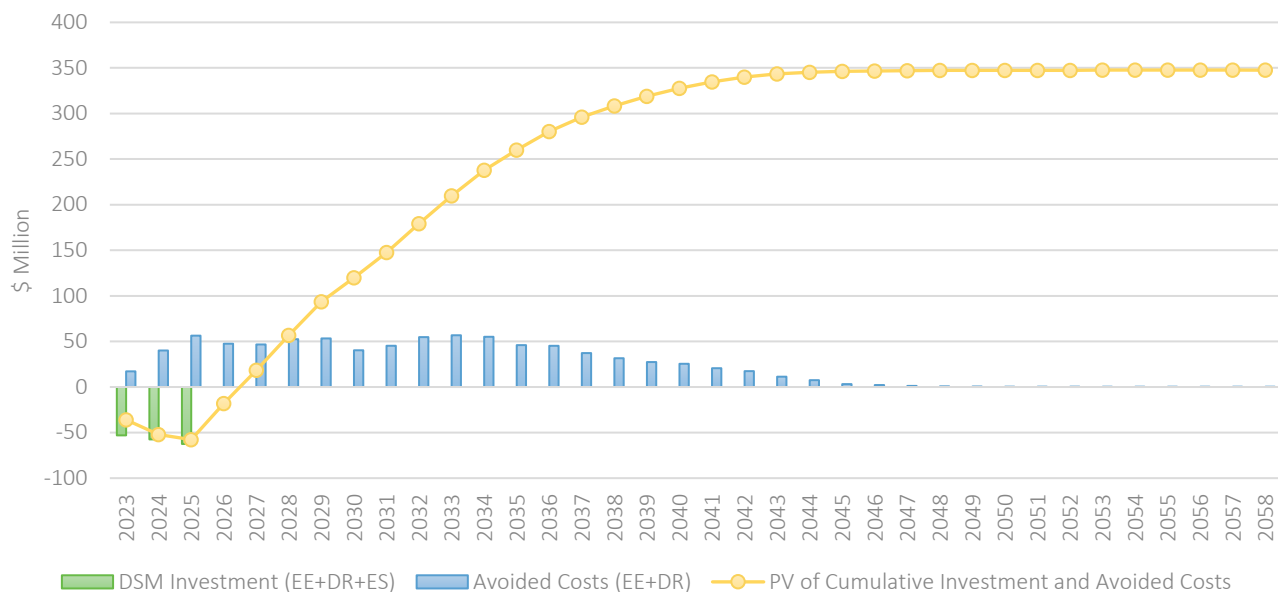
⁹ M08929, Exhibit N-1, EfficiencyOne, Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045, Prepared by Navigant for EfficiencyOne, August 14, 2019.

customer needs, technologies, market conditions, and regulatory requirements. E1 has considered the following areas of focus in the development of the Settlement Plan:

- increasing the diversity of energy and demand savings, to further help customers achieve cost-effective energy solutions;
- providing accessibility for a wider variety of market sectors and customer segments; and
- increasing the level of system-peak demand reduction benefits.

E1 considers affordability in the development of the Settlement Plan, both short- and long-term. E1's Settlement Plan has a payback of under five years – as illustrated in Figure 8. This means that by the end of 2027, the DSM investment will be fully recovered while ratepayers will continue to accrue benefits into the future.

Figure 8: Settlement Plan – Payback



DSM investment includes EE, DR, and Enabling Strategies. For DR, investment includes only the E1 portion of costs and benefits. Green bars are nominal investment. Blue bars are nominal avoided cost. Yellow line is a 2023 present value (PV) calculated using NS Power's Weighted Average Cost of Capital (WACC).

Payback graphs, by rate class, are provided in Attachment 1.

An analysis of the Settlement Plan's rate and bill impacts, which compares a "no-DSM" scenario (\$0 investment in 2023-2025 DSM) to the Settlement Plan's level of DSM, shows minor average rate impacts

(between -0.1 to +1.0 percent) by customer rate class over the study period (2023-2039). Average participants in each class will reduce their annual bills by between 1.2 and 7.9 percent.

Energy efficiency delivery under the Settlement Plan will offset just over 4,600 GWh of energy production over the lifetime of installed measures and reduce annual system-peak demand by 97 MW, providing lifetime benefits of \$540 million. For the first time, the Settlement Plan will also deliver flexible capacity to the electricity grid, with 18 MW of available DR capacity by the end of 2025, resulting in an additional \$3 million in lifetime benefits¹⁰.

2.2.2 PORTFOLIO-WIDE ASSUMPTIONS & DESIGN OBJECTIVES

E1's key global assumptions and design objectives for all modelled scenarios align with both the Plan's Guiding Principles and the Standardized Filing Framework (SFF). Specifically, the DSM Standards included in the SFF articulate that DSM Plans must balance the following aspects of DSM for the benefit of customers:

- Short- and long-term energy and capacity avoidance;
- Program delivery costs;
- Avoided energy and capacity investments;
- Non-electric and non-energy benefits;
- Diversity of program delivery;
- Business relationships and maintenance of market presence;
- Access to programs by all market sectors and rate classes by addressing barriers to participation; and
- Rate impacts.

The Balanced Portfolio section, below, further describes how E1 is considering the Balanced Plan aspects in the development and design of the 2023-2025 DSM Plan scenarios being explored. E1's Plan Guiding Principle, specifically related to Accessibility & Equity, ensures that programs offered are accessible on an equitable and non-discriminatory basis and reach potentially underserved markets.

¹⁰ DR lifetime benefits are calculated assuming DR programs do not continue beyond 2025

2.2.2.1 BALANCED PORTFOLIO – THE FRAMEWORK

On 22 July 2016, E1 filed a Consensus Agreement with the NSUARB¹¹. The Consensus Agreement was executed by E1, NS Power, the CA, the SBA, the IG, the MEU, the AEC, and the EAC. The Consensus Agreement included Demand Side Management Standards (“DSM Standards”), which articulate that DSM Plans must balance multiple aspects of DSM for the benefit of customers¹². The objectives of the DSM Standards are as follows:

- to ensure consistency in the overall DSM planning and evaluation process in Nova Scotia;
- to consolidate important decisions made by the NSUARB as they pertain to DSM regulation; and
- to ensure that DSM Resource Plans balance the multiple objectives of DSM.

Table 3, below, further describes the balanced plan considerations and how E1 has addressed these in the Settlement Plan.

Table 3: Balanced Plan Aspects Addressed in the Settlement Plan

Balanced Plan Aspects	2023-2025 Settlement Plan
Short- and long-term energy and capacity avoidance	• resource acquisition (measures with a diversity of short- and long-term savings) • market transformation (research and development)
Program Delivery Costs	• cost management strategies • incentive setting methodology
Avoided energy and capacity investments	• avoided cost of energy and carbon applied to EE measures • avoided costs of capacity, transmission, and distribution applied to EE and DR measures
Non-electric and non-energy benefits	• measure mix informed by historical participation, which inherently values customer perception of total project benefits • additional gas and biomass costs • reduced water cost

¹¹ M07543, 2016-2018 DSM Deferred Matters, Exhibit 3, Executed Revised Consensus Agreement, Appendix 1: Standardized Filing Framework, Section 4.3.1 Balanced Plan Approach, July 22, 2016, page 10.

¹² M07543, 2016-2018 DSM Deferred Matters, Exhibit 3, Executed Revised Consensus Agreement, Appendix 1: Standardized Filing Framework, Section 4.3.1 Balanced Plan Approach, July 22, 2016, page 9.

Balanced Plan Aspects	2023-2025 Settlement Plan
Diversity of program delivery	• 356 measures, with measure lives ranging from 1 to 36 years • 14 EE program components; 2 DR program components • diverse markets (homeowners, renters, building owners, builders & developers, small business, industry, commercial, institution) • diverse delivery types (energy assessments and feasibility studies, point-of-sale and post-purchase rebates, direct installation and self-serve participation channels, behaviour)
Business relationships and maintenance of market presence	• Enabling Strategies key theme is partnership development • maintains Efficiency Preferred Partner network • maintains current portfolio of program components, with the exception of New Home Construction which is transitioning to a market transformation approach, while adding Residential Behaviour and Affordable Single-family Homes
Access to programs by all market sectors and rate classes by addressing barriers to participation	• low-income investment – 22% of EE Portfolio (including Enabling Strategies) and 21% of total portfolio (including DR, EE, and Enabling Strategies) • energy savings split of 46% Residential and 54% BNI • EE program funding split of 55% Residential and 45% BNI • total program (i.e. EE + DR) funding split of 55% Residential and 45% BNI Suite of residential and BNI program components targeting road range of end uses and customer segments, including the following new portfolio additions: • new Residential Behaviour program component • new electrician-installed measures and smart thermostat offering within the Efficient Products Installation program component • new residential Affordable Single-family Homes program component • new direct install service for small businesses through Small Business Energy Solutions • prioritizes underserved markets and communities through education & outreach • prioritizes market transformation research and development targeted at the residential new construction market as a whole
Rate impacts	• RBIA performed on DSM model results, as part of Plan development • cumulative value of avoided costs will exceed the initial investment by the end of 2027

- 1
- 2 With the Balanced Plan Approach and Balanced Portfolio framework in mind, the following design
- 3 objectives were applied to the Settlement Plan:
- 4 • investment in low-income (LI): 17% to 22% of total energy efficiency portfolio investment;
- 5 • investment split: 50% Residential (Res) and 50% BNI programs; and

- energy savings split: 40% Res and 60% BNI programs.

Table 4, below, further describes key global assumptions applied to the Settlement Plan. The column “Model” denotes the applicability of described model inputs and assumptions to the model type – i.e. EE, DR and, in some cases, both.

Table 4: Key Global Assumptions in the 2023-2025 Settlement Plan Development

Key Global Assumptions		Model	
ITEM	DESCRIPTION OF MODEL INPUTS & ASSUMPTIONS	EE	DR
Avoided Costs	- Avoided costs of both energy and capacity were based on NS Power’s 2020 IRP Scenario 2.0C (Avoided Cost Run). Attachment 2 – Avoided Costs Brief, provided to the DSMAG in November 2021, provides details on E1’s methodology. - DR is assumed to have no energy impacts, and therefore, avoided cost of energy is negated (i.e. zero); avoided cost of capacity uses the same methodology as EE.	X	X
	Transmission and distribution avoided costs were as developed by NS Power and the DSMAG in 2020, with remaining issues addressed in 2021. E1 is using the system wide costs from NS Power’s May 2021 release, adjusted for inflation (2% annually).	X	X
	Avoided cost of carbon was developed using the Federal Policy Position¹³ Document, inclusive of the federal backstop trajectory (\$170 per tonne by 2030, and held constant, in real terms, beyond 2030). This price was applied to the difference in CO₂ emissions between IRP case 2.0C, and a reference case containing no energy efficiency activities. The factors are then combined to produce a price per kWh of energy saved for the avoided costs of carbon.	X	
Line Loss Factors	- Energy: residential (9.5%) and BNI (6.4%) were updated using the latest figures established in E1’s 2020 DSM Program Evaluation Report. This impacts the conversion from savings at meter to savings at the generator. - Demand: residential (14.7%) and BNI (6.1%) were updated using the latest figures established in E1’s 2020 DSM Program Evaluation Report. This impacts the conversion from savings at meter to savings at the generator.	X	X
Incentive Development	EE incentive development: unless otherwise noted in individual scenario descriptions, incentives were set to current levels with the exception of new initiatives and instances where incentives were adjusted to account for future expectations or program activity goals (e.g. greater online activity within residential Instant Savings or increased incentive planned to increase participation in Custom). A financial simulation was applied to all incentives as part of DSM Plan development, which analyzed incentive levels against	X	

¹³ Environment and Climate Change Canada. A Healthy Environment and A Healthy Economy, 2020.

Key Global Assumptions		Model	
ITEM	DESCRIPTION OF MODEL INPUTS & ASSUMPTIONS	EE	DR
Incentive Development	thresholds contained in the Incentive Setting Methodology, as accepted by the NSUARB in 2017.		
	DR incentives development: updated from the 2019 DSM Potential Study based on updated information from Guidehouse as well as preliminary incentive insights from DR pilots and projects within Nova Scotia.		X
Incremental Costs	Incremental costs are intended to represent the difference in cost between baseline and efficient energy efficiency measures and have been adapted from previous E1 work products (e.g. the 2020-2022 DSM Resource Plan). As part of DSM Resource Plan development, Guidehouse has reviewed these costs and provided updates for certain measures. Incremental costs are inflated in each of the plan years beyond 2023 at a rate of 2%.	X	
Administrative Costs	- A new fixed/variable methodology was used to develop the administrative costs for the 2023-2025 Settlement Plan. The change in approach from previous DSM Plans was in response to the KPMG study. - Administrative costs have been divided and allocated into variable and fixed cost categories. The variable cost category allocates program costs such as evaluation, marketing, and program management costs as a percentage of incentive costs. - The fixed cost category includes costs such as rent, insurance, office and salary expenses and have been set by reviewing contractual commitments, historical and current spending levels. Fixed costs have been allocated to program components based on number of Full-Time Equivalent (FTE) staff.	X	
	DR administrative costs are based on an estimate of required multiplied by E1's assumed FTE cost including overhead. The FTE estimates have been updated from the 2019 DSM Potential Study based on information from Guidehouse, preliminary insights from DR Pilots within Nova Scotia, and E1 experience with similar EE program delivery.		X
Codes & Standards	Forward-looking assumptions have been made with respect to codes & standards changes in two key areas: lighting and heat pumps. - Lighting: current evaluation assumptions provide little credit past 2023 in terms of first-year savings for screw-in compact fluorescent lamp (CFL) lighting in the residential sector. Dual baseline approach for screw-in lighting assumes limited residential savings from these measures in 2024 and beyond. - Heat pump savings in Green Heat are derated within the ProCESS™ model to account for expected decreases in evaluated net energy savings across the Plan period.	X	
Participation Estimation & Development Approach	Estimation of EE participation: initial development using internal forecasting, which was adjusted for future expectations through subject-matter expert reviews, to form the current state assumptions, subsequently further updated through subject-matter expert review in draft versions of the DSM Plan – details provided as Attachment 3 – Guidehouse Participation Memorandum.	X	

Key Global Assumptions		Model	
ITEM	DESCRIPTION OF MODEL INPUTS & ASSUMPTIONS	EE	DR
Participation Estimation & Development Approach	Development of DR participation: updated Potential Study assumptions; DR uses a top-down approach to estimate an eligible pool of participants and estimates of how many eligible customers would be willing to participate in a DR program option. A participation ramp was also applied to ensure DR programs scale-up in a feasible way (based on Guidehouse's expertise and E1's experience with similar program delivery models).		X
Low-Income Investment Levels	Incidental EE low-income impact weightings from 2020 (i.e. energy savings, demand savings, investment) were applied to calculate low-income impacts in the 2023 to 2025 period.	X	
Market Rates	- Weighted Average Cost of Capital (WACC): NS Power's 2021 pre-tax WACC of 6.33% is used to calculate the present values of avoided utility costs. - Inflation Rate: using an annual inflation rate of 2%.	X	X

2.3 MODELLING

2.3.1 OBJECTIVES OF THE MODELLING PROCESS

The modelling process, and its associated software tools, were used to support the quantitative development of the Settlement Plan for both EE and DR. Modelling and software tools support the development, communication, and regulatory processes by providing:

- detailed cost effectiveness impacts associated with DSM Plan scenarios;
- detailed energy and demand impacts, as applicable, to support the development of performance indicators and performance targets;
- detailed views and estimations of DSM Plan participation; and
- detailed views and estimations of DSM Plan investment.

The critical objectives of the DSM plan modelling process are to provide accuracy and detail in development, as well as allowing for the measurement of success for the Settlement Plan, as approved by the NSUARB.

2.3.2 DSM MODELLING TOOLS & SOFTWARE

2.3.2.1 ENERGY EFFICIENCY MODEL

The "Model" is a DSM portfolio design tool used to inform E1's DSM Resource Plans. E1 engaged Guidehouse, formerly Navigant Consulting, to provide its ProCESS™ short-term DSM planning tool for the purpose of modelling the energy efficiency portfolio for E1's Settlement Plan.

Guidehouse's ProCESS™ model is developed on the Analytica® software platform and was used for the first time for the development of E1's 2020-2022 DSM Plan. The ProCESS™ model is specifically designed for short-term planning exercises (e.g. DSM Plans). The ProCESS™ model does not predict measure uptake by modelling customer behaviour, a feature that has limited usefulness in short-term planning exercises.

At the outset of the modelling process, E1 and Guidehouse developed a set of input data to serve as the basis for all subsequent modelling steps associated with the Settlement Plan. Input data included line loss factors, customer rate information, avoided costs, discount rates, and all measure technical information (e.g. measure life, annual energy and system-peak demand savings, incremental costs, incentives). Measure data were initially developed from current E1 data, and subsequently modified to reflect differences in characterization expected across the 2023-2025 period.

Following the development and inputting of data into the model, Guidehouse prepared the model to reach an operational state and initial test runs were performed. The steps in the development of E1's model input assumptions and results are described in Attachment 3 – Guidehouse Participation Memorandum.

2.3.2.2 DEMAND RESPONSE MODEL

Guidehouse completed DR modelling using its DRSim™ model, which was also used in E1's 2019 Potential Study. The steps to running the model are outlined in Table 5. These steps were updated for the 2023-2025 DR model. Guidehouse and E1 utilize a potential study framework for modelling DR because it is the best available information for estimating participation. This differs from EE modelling where actual historical results can be used to model participation.

Table 5: DR Modelling Steps¹⁴

Step 1: Market Characterization	Characterize market for DR potential estimation: number of customers and coincident peak load estimates by customer class and building type.
Step 2: Develop Baseline Projections	Define peak and develop baseline peak demand projects over the study period.
Step 3: Define DR Options	Define and characterize DR options (i.e. technologies) and map applicable options to relevant customer classes

¹⁴ Adapted from Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045. Navigant Consulting. 2019. Figure 10-1, page 86. See M08929, Exhibit N-1, EfficiencyOne, August 14, 2019.

Step 4: Develop Key Assumptions for DR Capacity and Costs	• Develop assumptions for participation, unit load reduction, and itemized cost for each DR option.
Step 5: Estimate DR Capacity and Costs, and Assess Cost-Effectiveness	• Present DR capacity estimates, annual costs, levelized costs, and cost-effectiveness results by DR option and customer segments.
Step 6: Scenario Analysis	• Present results by scenario, which consider variations in available technologies/delivery pathways, and participation.

The DR model steps occur independently of the EE modelling process, which is described below. While DR and EE are modelled using different tools and software, they are not developed in isolation. Certain input assumptions are present in both models (e.g. inflation). Some steps and phases overlap and interact, as described in the section below. The DR model leverages EE model outputs in Phase 4 of the EE modelling process, and EE leverages DR model outputs in the final phases of modelling the DSM portfolio.

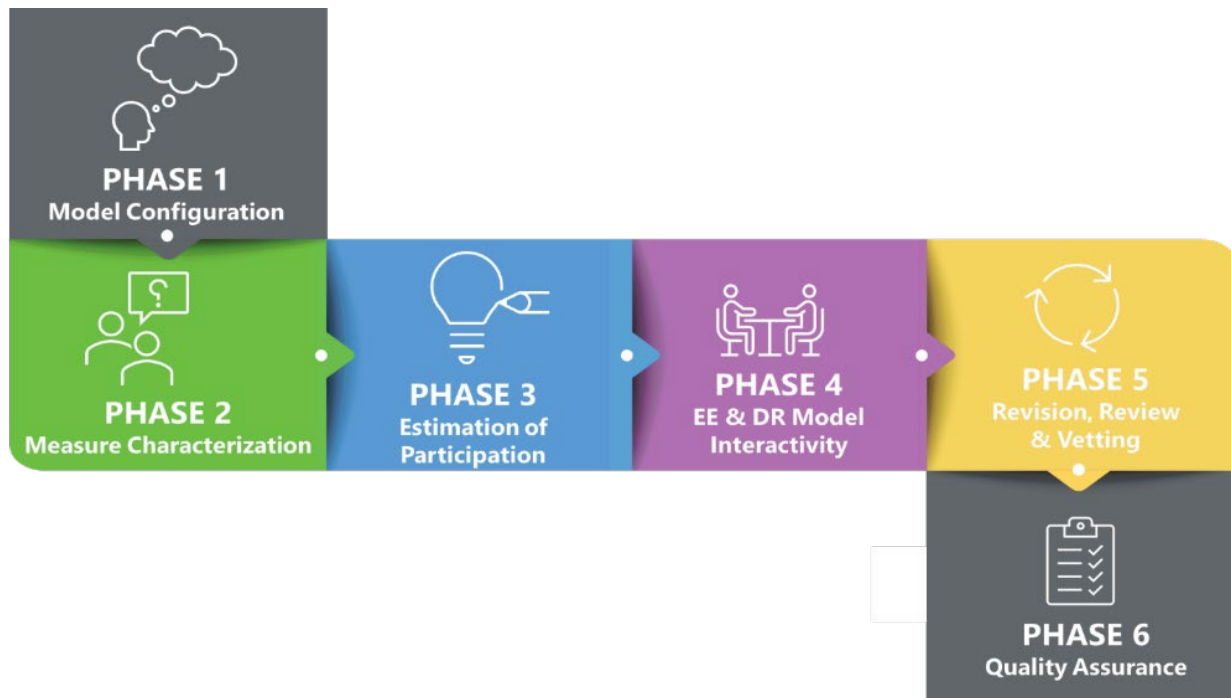
2.3.3 THE MODELLING PROCESS

The 2023-2025 Settlement Plan modelling process includes the following six phases:

1. Model Configuration
2. Measure Characterization
3. Estimation of Participation
4. Model Interactivity of EE and DR
5. Review, Revision, and Vetting
6. Quality Assurance

The six components of the modelling process are illustrated in Figure 9, below, and described in the sections that follow.

Figure 9: Phases in the 2023-2025 Settlement Plan Modelling Process



2.3.3.1 PHASE 1 – MODEL CONFIGURATION

The model configuration process involves the initial configuration of the modelling tools associated with the Settlement Plan development:

1. the DRSim™ model, which models DR activities within the Settlement Plan; and
2. the ProCESS™ model, which supports energy efficiency activity development.

Specific configuration activities include the adjustment of general model parameters including cost effectiveness testing methodology, administrative cost build-out methodologies, and other key methodological areas within the models. This phase also includes providing the model with initial global assumptions, such as avoided cost information and electricity retail rates.

2.3.3.2 PHASE 2 – MEASURE CHARACTERIZATION

This modelling phase includes the detailed characterization of E1's measures, and the mix of measures it incorporates in both programs and program components. Key variables associated with each measure characterization include annual energy and/or demand savings (as applicable), incremental cost information, incentives, and water and/or gas impacts (if applicable).

Energy efficiency measure characterizations are based on final 2020 DSM evaluation results, with certain adjustments for measures with markedly different expectations for energy or demand savings across the 2023-2025 period (e.g. heat pumps, which were modelled with declining net energy savings). The measure characterization process for energy efficiency initially took place as part of E1's current state analysis, with updates and certain additions (e.g. for new initiative development) occurring throughout the various phases of initial development and stakeholder and internal review.

2.3.3.3 PHASE 3 – ESTIMATION OF PARTICIPATION

Participation estimates for energy efficiency were initially informed by near-term forecasts of 2021 participation expectations, as part of E1's current state analysis, which provided an initial view of status-quo operation of programs over the 2023-2025 period. New initiative development was also required in service of E1's design objectives for the Settlement Plan (e.g. a low-income investment percentage of 17-22%). For these new initiatives, participation was estimated by E1's internal SMEs based on factors such as historical insights and experience, and market response in other jurisdictions.

Participation estimates for energy efficiency were then iteratively refined over the course of the stakeholder and internal review processes, with E1's internal SMEs providing direct feedback on multiple occasions as described in Phase 5, below.

2.3.3.4 PHASE 4 – EE & DR MODEL INTERACTIVITY

The Settlement Plan makes use of separate models for EE and DR. These separate models interact with one another in three primary ways:

1. EE savings levels change the baseline projection energy sales; the DR baseline projection must be calibrated to a specific EE savings level;
2. some measures (i.e. smart thermostats) are contained within the EE ProCESS™ model and the DRSim™ model. For these measures, the participation estimates contained within the ProCESS™ model inform the available participation associated in the DRSim™ model; and
3. for measures contained in both the EE and DR models, measure costs are allocated based on the percent of total avoided costs for EE and DR. In the EE and DR model integration, these costs are synced up to ensure they are allocated properly.

2.3.3.5 PHASE 5 – REVISION, REVIEW & VETTING

Following the production of draft model outputs, E1 performs model revisions, leveraging the feedback of internal subject matter experts, Guidehouse, and DSMAG members to confirm and adjust model parameters. These changes are driven by adjustments to the DSM Plan itself, or by adjustments to key assumptions to improve the accuracy of the modelling process.

This phase is crucial, as it allows for the alignment of E1's qualitative and quantitative design efforts in service of E1's design objectives. This process is repeated several times as part of DSM Plan development. The vetting process involves analysis of the model outputs. This analysis was informed by external expert support and internal teams (data analytics, service delivery, marketing, technical teams) to assess the validity of achieving results. The review includes an examination of energy savings at the program component and measure level to consider the reasonableness of the model output. Refinements to the model were performed in response to this analysis and updated model runs were completed. This is part of an iterative process, which results in revised participation estimates, model interaction, and new model outputs.

2.3.3.6 PHASE 6 – QUALITY ASSURANCE

All assumptions used in final DSM Plan models undergo further quality assurance to ensure accuracy in all assumptions and variables used in the DSM Plan modelling process.

2.4 COST-EFFECTIVENESS

Cost effectiveness testing is used to quantitatively assess and evaluate demand side resources through a comparison of benefits and costs expressed as both the dollar value of the net benefit (or cost) and as a ratio of benefits to costs. DSM cost effectiveness can be assessed at various levels (e.g. measure, program, portfolio) using a variety of tests. Each test systematically assesses cost effectiveness from a different perspective, depending on the key question it seeks to answer. Tests can be used for different purposes and jurisdictions will emphasize specific tests depending on the policy environment and objectives of that particular jurisdiction.

To assess the cost-effectiveness of the Settlement Plan, E1 used two industry standard screening tests: the Total Resource Cost (TRC) test, used as the screening test for DSM in Nova Scotia at the NSUARB program

level, and the Program Administrator Cost (PAC) test for informational purposes. For the first time, E1 has included avoided costs of carbon in both the TRC and PAC tests as per the 2011 directive from the NSUARB (M03669)¹⁵. Both tests make use of NS Power's utility Weighted-Average Cost of Capital (WACC) as the discount rate. E1 has provided TRC and PAC results without avoided costs of carbon for informational purposes. Cost effectiveness testing was performed on both the EE and DR portfolios, the results of which are further presented in Section 3.3.

2.4.1 TOTAL RESOURCE COST TEST

Best practice¹⁶ recommends the use of one consistent cost-effectiveness test to screen both EE and DR. The TRC was used as the primary test of E1's DSM investments, per the NSUARB decision¹⁷ that the TRC test should be applied at the program level for DSM Plan investments. However, some benefit and cost components of the TRC calculation vary between EE and DR. This is further described in Table 6, below.

Table 6: Benefit and Cost Components in the Total Resource Cost Test Calculations for EE and DR

Component	Description	Benefit or Cost
Avoided Cost of Transmission & Distribution	EE & DR – the avoided cost of transmission and distribution represents the costs avoided, due to DSM, on transmission and distribution infrastructure within the NS Power system.	Benefit
Avoided Cost of Capacity	EE & DR – the avoided cost of capacity represents the costs avoided, due to DSM, associated with reductions in generation capacity on the NS Power system.	Benefit
Avoided Cost of Energy	EE – the avoided cost of energy represents the energy-associated (e.g. fuel) costs avoided associated with DSM.	Benefit
	DR – assumed to have no energy impacts, and therefore, the avoided cost of energy is negated (i.e. zero) in the TRC calculation.	n/a
Avoided Cost of Carbon	EE – the avoided cost of carbon represents the market-based price of carbon expected to be realized through investments in DSM.	Benefit

¹⁵ M03669, NSUARB Order, In the Matter of the Efficiency Nova Scotia Corporation Act and In the Matter of an Application by Efficiency Nova Scotia Corporation for Approval of its Electricity Demand Side Management Plan for 2012 (30 June, 2011) and M03669, NSUARB Decision, In the Matter of the Efficiency Nova Scotia Corporation Act and In the Matter of an Application by Efficiency Nova Scotia Corporation for Approval of its Electricity Demand Side Management Plan for 2012, (30 June, 2011), at para 82.

¹⁶ National Energy Screening Project. (2020) National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources.

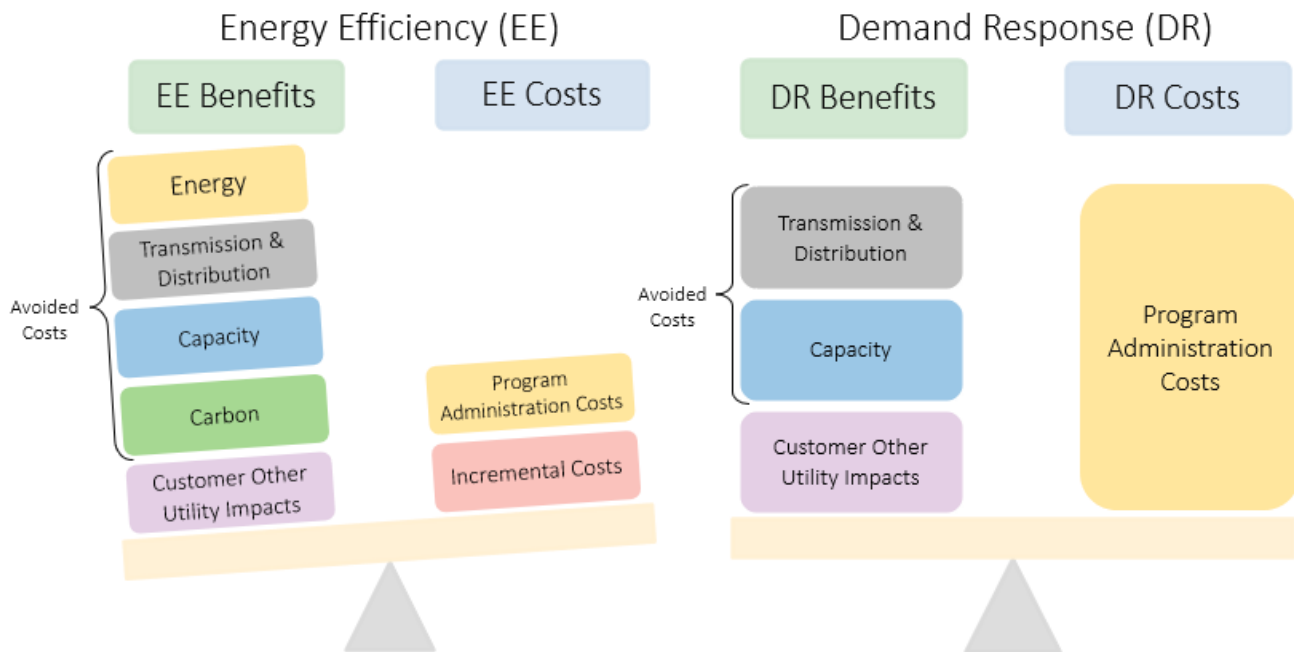
¹⁷ M03669, NSUARB Order, In the Matter of the Efficiency Nova Scotia Corporation Act and In the Matter of an Application by Efficiency Nova Scotia Corporation for Approval of its Electricity Demand Side Management Plan for 2012 (30 June, 2011) and M03669, NSUARB Decision, In the Matter of the Efficiency Nova Scotia Corporation Act and In the Matter of an Application by Efficiency Nova Scotia Corporation for Approval of its Electricity Demand Side Management Plan for 2012, (30 June, 2011), at para 82.

Component	Description	Benefit or Cost
Avoided Cost of Carbon	DR – assumed to have no energy impacts, and therefore, the avoided cost of carbon is negated (i.e. zero) in the TRC calculation.	n/a
Customer Other Utility Impacts	EE & DR – includes the avoided customer cost of water, the customer cost of wood/pellets, and the additional customer cost of gas. Combined with electricity system avoided costs, the net impact can be either a benefit or a cost, depending on the type of measure being implemented.	Both
Program Administration Costs	EE – includes: - administrative costs of delivering EE programs, e.g. overhead, facilities, and FTEs. - Enabling Strategies investment, included as program administration cost, and applied to at the EE portfolio-level.	Cost
Program Administration Costs	DR – includes: - administrative costs of delivering DR programs, e.g. overhead, FTEs. - For NS Power’s portion information technology costs such as software licensing. - costs to develop and deliver DR programs, e.g. third-party delivery costs, marketing and recruitment, etc.	Cost
Incremental Costs	EE – includes: - incremental costs for incentive measures. - direct install costs for direct installation programs, e.g. Efficient Product Installation.	Cost

As described in Table 6, above, benefits such as avoided cost of energy and avoided cost of carbon are not applicable for the TRC calculation of DR.

In both instances (i.e. EE and DR), the benefit-cost ratios are conducted on a present value basis for the full lifetime of impacts. However, the TRC calculation for EE considers only the cost and benefit impacts over the three-year DSM Plan period. For DR, the cost and benefit impacts are levelized over a ten-year timeframe, with the assumption that DR programming runs for 10 years. The balance of these cost and benefit components are further illustrated in Figure 10, below. The benefits and costs, on a net present value basis are then summed (respectively) and expressed as a ratio of benefits divided by costs.

1 Figure 10: TRC Benefit and Cost Components for Energy Efficiency and for Demand Response



2
3 For energy efficiency, administrative costs are included within the total resource cost test at different levels
4 within the ProCESS™ model – an example are fixed administrative costs, which are modelled occurring at
5 the program level. These costs are then cascaded down to the program component and measure levels on
6 the basis of TRC net benefits, such that all costs are reflected within measure level cost effectiveness
7 testing. The PAC test is described in the next section.

8 9 2.4.2 PROGRAM ADMINISTRATOR COST TEST

10 The PAC test provides an assessment of the cost effectiveness of DSM programs from the perspective of
11 the utility and ratepayer. This is contrasted with the TRC test, which provides a view of cost effectiveness
12 from the combined perspective of the utility/ratepayer, as well as the program participant. Table 7, below,
13 shows the costs and benefits included in the PAC.

14
15 Table 7: Program Administrator Cost Test Components

Component	Description	Benefit or Cost
Avoided Cost of Transmission & Distribution	EE & DR – the avoided cost of transmission and distribution represents the costs avoided, due to DSM, on transmission and distribution infrastructure within the NS Power system.	Benefit

Component	Description	Benefit or Cost
Avoided Cost of Capacity	EE & DR – the avoided cost of capacity represents the costs avoided, due to DSM, associated with reductions in generation capacity on the NS Power system.	Benefit
Avoided Cost of Energy	EE – the avoided cost of energy represents the energy-associated (e.g. fuel) costs avoided associated with DSM.	Benefit
	DR – assumed to have no energy impacts, and therefore, the avoided cost of energy is negated (i.e. zero) in the PAC calculation.	n/a
Avoided Cost of Carbon	EE – the avoided cost of carbon represents the market-based price of carbon expected to be realized through investments in DSM.	Benefit
	DR – assumed to have no energy impacts, and therefore, the avoided cost of carbon is negated (i.e. zero) in the PAC calculation.	n/a
Customer Other Utility Impacts	EE & DR – includes the avoided customer cost of water, the customer cost of wood/pellets, and the additional customer cost of gas. Combined with electricity system avoided costs, the net impact can be either a benefit or a cost, depending on the type of measure being implemented.	Both
Program Administration Costs	EE – includes: • administrative costs of delivering EE programs, e.g. overhead, facilities, and FTEs. • Enabling Strategies investment, included as program administration cost, and applied to at the EE portfolio-level.	Cost
	DR – includes: • administrative costs of delivering DR programs, e.g. overhead, FTEs. • For NS Power's portion information technology costs such as software licensing. • costs to develop and deliver DR programs, e.g. third-party delivery costs, marketing and recruitment, etc.	
Incentives	EE & DR – incentives are costs for the utility and ratepayers, from the perspective of the PAC.	Cost

1

2 In the TRC, incentives are a benefit for participants and a cost for the utility, therefore, they are considered

3 a 'transfer' in the TRC test and are not included as a cost or benefit. In contrast, the PAC includes incentives

4 on the cost-side of the test. In the PAC, as with the TRC, benefits such as avoided cost of energy and avoided

5 cost of carbon are not applicable for the calculation of DR. The PAC benefit-cost ratios are also conducted

6 on a present value basis for the full lifetime of impacts, as with the TRC. The benefits and costs, on a net

7 present value basis, are then summed (respectively) and expressed as a ratio of benefits divided by costs.

- 1 E1 has presented PAC test results on an information-only basis. The PAC test provides information relating
- 2 to the ratepayer and utility costs and benefits associated with the Settlement Plan, and notably excludes
- 3 voluntary participant contributions which are included in the TRC. Cost effectiveness results for the
- 4 Settlement Plan, by sector and program, are provided in Section 3.3.

3. 2023-2025 SETTLEMENT PLAN

The 2023-2025 Settlement Plan represents a comprehensive suite of programs and service offerings for Nova Scotia electricity customers. The main goal of each energy efficiency program is to eliminate energy waste, in turn reducing demand for energy imports, reducing household and business energy costs resulting in bill savings, as well as helping with environmental compliance by lowering GHG emissions. The main goal of the DR program is to make flexible capacity available to the utility that can be called upon during peak times. In the long-term this can offset the need for new generation, transmission, and distribution infrastructure. Figure 11, below, provides highlights of the Settlement Plan.

Figure 11: 2023-2025 Settlement Plan – Portfolio-level Insights

Carbon Emissions Avoided	
First-Year CO ₂ e Savings (kt)	326
Lifetime CO ₂ e Savings (kt)	1,742
Portfolio Summary (2023-2025)	
First-Year Energy Savings (GWh)	412.7
Peak Demand Savings (MW)	96.7
Investment (\$ million)	173.0
% of Plan Investment in Low-Income	20.9%
Energy & Demand Savings	
Lifetime Energy Savings (GWh)	4,681
Weighted Average Measure Life (yrs)	11.3
Energy Savings as % of NS Power Load	1.2%
DR as % of NS Power Peak Load ^a	1.0%
Energy Savings (EE) Split (RES/BNI)	46/54
Demand Savings (EE) Split (RES/BNI)	45/55
Demand Savings (DR) Split (RES/BNI)	40/60
% of Non-Lighting Energy Savings	69.2%
Energy Efficiency (EE) Investment	
EE Investment Split (RES/BNI) ^b	55/45
First-Year Unit Cost (\$/kWh)	0.39
Lifetime Unit Cost (\$/kWh)	0.035
Lifetime Benefits (\$ million) ^d	540
Net Benefits (\$ million) ^d	377
Demand Response (DR) Investment	
10 Year Levelized Cost (\$/kW-yr) ^c	229.59
Lifetime Benefits (\$ million) ^d	3
Net Benefits (\$ million) ^d	-8
DR Investment Split (RES/BNI) ^b	54/46

^a Percentage of NS Power peak load by 2025

^b Excluding Enabling Strategies investment

^c Calculated by taking the net present value of costs and MWs for each DR pathway over the 2022-2031 timeframe; includes all E1 and NS Power costs

^d EE and DR net benefits are calculated based on the Program Administrator Cost (PAC). For EE, the lifetime benefits are counted and, for DR, the first three years (2023-2025). In DR, the Critical Peak Pricing (CPP) only includes smart thermostat related costs/benefits.

3.1 SETTLEMENT PLAN – SAVINGS & INVESTMENT

In 2023-2025, E1 will invest \$173.0 million (in nominal dollars) to achieve 412.7 GWh of incremental cumulative net energy savings, 96.7 MW of cumulative system-peak demand savings (inclusive of both demand reductions – 78.8 MW, and DR capacity additions – 17.9 MW), and 4,681 GWh of cumulative net lifetime energy savings at the generator. Table 8 presents program investment budgets and targets for the planned 2023-2025 portfolio.

Table 8: 2023-2025 Settlement Plan Investment and Savings

Year	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Weighted Average Measure Life (years)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
								incl. carbon	excl. carbon	incl. carbon	excl. carbon
2023	53.1	172.0	120.7	1,502	12.4	26.9	3.0	2.0	1.4	2.9	2.0
2024	57.5	179.0	142.6	1,540	10.8	25.6	10.0	2.0	1.4	2.8	2.0
2025	62.5	191.9	149.5	1,639	11.0	26.3	17.9	2.0	1.4	2.9	2.1
Total	173.0	542.8	412.7	4,681	11.3	78.8	17.9	2.0	1.4	2.9	2.0

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021. Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission, distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of benefits).

^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes only.

^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. PAC excluding carbon is provided for informational purposes only.

1 Table 9: 2023-2025 Settlement Plan Investment and Savings, by Program Component

2023-2025	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
							incl. carbon	excl. carbon	incl. carbon	excl. carbon
Residential (Res) Energy Efficiency (EE) Programs										
Efficient Product Rebates	14.1	30.8	32.3	279.0	3.5	-	1.1	0.7	2.2	1.4
Appliance Retirement	3.1	2.0	3.7	15	0.5		1.1	0.6	0.6	0.4
Instant Savings	11.0	28.8	28.6	264	2.9		1.1	0.7	2.6	1.7
Existing Residential	67.0	163.0	156.7	1,292	30.7	-	1.4	1.0	2.6	1.9
Efficient Product Installation	10.6	24.3	36.2	220	4.9		1.9	1.3	1.9	1.3
Affordable Multi-family Housing	4.0	11.6	5.6	102	1.7		1.2	0.9	2.9	2.1
Home Energy Assessment	11.7	66.9	25.7	515	13.0		2.0	1.6	5.7	4.4
Green Heat	6.7	29.7	10.7	193	8.2		1.5	1.2	4.4	3.5
Mi'kmaw Home Energy Efficiency Project	3.7	3.3	1.6	30	0.5		0.7	0.5	0.9	0.6
Affordable Single-Family Homes	24.7	18.0	8.6	164	2.5		0.5	0.4	0.7	0.5
Residential Behaviour	5.5	9.3	68.2	68	0.0		1.5	0.8	1.5	0.8
New Residential	0.8	3.9	0.4	13	1.3	-	2.6	2.4	4.8	4.4
Low-Income Participation ^e	35.2	42.8	36.5	384	6.5		1.0	0.7	1.2	0.8
Res EE Programs Total	81.9	197.8	189.4	1,584	35.4	-	1.4	1.0	2.5	1.8
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs										
Efficient Product Rebates	23.2	174.3	109.1	1,623	20.6	-	3.7	2.5	7.5	5.1
Custom Incentives	25.2	109.1	77.5	940	15.2	-	2.5	1.7	4.3	2.9
Custom	22.4	107.0	69.5	925	14.3		2.6	1.8	4.8	3.2
Strategic Energy Management & Energy Management Information Systems	2.8	2.1	8.0	15	0.9		0.9	0.5	0.8	0.4
Direct Installation	19.8	58.8	36.7	533	7.6	-	2.2	1.5	3.0	2.0
Low-Income Participation ^e	0.6	4.7	2.9	43	0.8		2.8	1.9	7.6	5.2
BNI EE Programs Subtotal	68.2	342.2	223.3	3,097	43.4	-	2.9	2.0	5.0	3.4
Total EE Programs	150.2	539.9	412.7	4,681	78.8	-				
Enabling Strategies (ES)										
Education & Outreach	4.4									
Development & Research	4.5									
Other Enabling Strategies	4.1									
Total ES	12.9									
EE Portfolio Total (EE + ES)	163.0	539.9	412.7	4,681	78.8	-	2.0	1.4	3.3	2.3
Demand Response (DR) Program										
Residential Demand Response	5.5					7.1		0.8		0.6
BNI Demand Response	4.6					10.7		2.7		0.8
DR Program Total	10.0	2.9	-	-	-	17.9		1.1		0.7
DSM Portfolio Total (EE + ES + DR)	173.0	542.8	412.7	4,681	78.8	17.9	2.0	1.4	2.9	2.0

2 Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may
3 not add correctly, due to rounding.

4 Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP
5 using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.
6 Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

7 ^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits
8 to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event
9 calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

10 ^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission,
11 distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the
12 avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of
13 benefits).

14 ^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs
15 and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes
16 only.

17 ^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to
18 include the expected full program life. PAC excluding carbon is provided for informational purposes only.

E1 estimates that the 2023-2025 Settlement Plan will produce incremental CO₂e reductions of 326 kt over the three-year Plan period and cumulative net lifetime CO₂e reductions of 1,742 kt¹⁸.

Table 10, Table 11, and Table 12 provide the program investment budgets and targets for 2023, 2024 and 2025, respectively.

Table 10: 2023 Settlement Plan Investment and Savings, by Program Component

2023	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
							incl. carbon	excl. carbon	incl. carbon	excl. carbon
Residential (Res) Energy Efficiency (EE) Programs										
Efficient Product Rebates	4.0	9.1	10.9	83	1.2	-	1.1	0.7	2.3	1.4
Appliance Retirement	1.0	0.7	1.2	5	0.2		0.9	0.5	0.6	0.4
Instant Savings	2.9	8.4	9.7	78	1.0		1.2	0.7	2.9	1.8
Existing Residential	20.9	49.8	37.3	403	10.3	-	1.5	1.1	2.4	1.7
Efficient Product Installation	3.1	6.6	11.2	59	1.7		2.2	1.4	2.2	1.4
Affordable Multi-family Housing	1.3	3.8	1.9	34	0.6		1.2	0.9	2.9	2.0
Home Energy Assessment	3.9	21.7	8.6	172	4.3		2.0	1.5	5.6	4.2
Green Heat	2.2	9.6	3.6	64	2.7		1.5	1.2	4.3	3.4
Mi'kmaw Home Energy Efficiency Project	1.2	1.1	0.5	10	0.2		0.9	0.6	0.9	0.6
Affordable Single-Family Homes	8.1	5.9	2.9	55	0.8		0.7	0.5	0.7	0.5
Residential Behaviour	1.1	1.1	8.7	9	0.0		0.9	0.5	0.9	0.5
New Residential	0.8	3.9	0.4	13	1.3	-	2.6	2.4	4.8	4.4
Low-Income Participation ^e	11.3	13.3	10.3	121	2.2		1.0	0.7	1.2	0.8
Res EE Programs Subtotal	25.7	62.8	48.6	499	12.8	-	1.5	1.1	2.4	1.8
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs										
Efficient Product Rebates	7.4	55.5	35.3	525	6.7	-	3.7	2.5	7.5	5.0
Custom Incentives	8.2	34.8	24.9	305	5.0	-	2.5	1.7	4.2	2.8
Custom	7.3	34.1	22.3	300	4.7		2.6	1.8	4.7	3.1
Strategic Energy Management & Energy Management Information Systems	0.9	0.7	2.7	5	0.3		0.9	0.5	0.7	0.4
Direct Installation	6.4	18.7	11.9	172	2.5	-	2.2	1.5	2.9	2.0
Low-Income Participation ^e	0.2	1.5	0.9	14	0.3		2.8	1.9	7.5	5.1
BNI EE Programs Subtotal	22.0	108.9	72.1	1,003	14.2	-	2.9	2.0	4.9	3.3
Total EE Programs	47.8	171.7	120.7	1,502	26.9	-				
Enabling Strategies (ES)										
Education & Outreach	1.4									
Development & Research	1.5									
Other Enabling Strategies	0.9									
Total ES	3.8									
EE Portfolio Total (EE + ES)	51.5	171.7	120.7	1,502	26.9	-	2.0	1.4	3.3	2.3
Demand Response (DR) Program										
Residential Demand Response	0.4					0.2		0.8		0.6
BNI Demand Response	1.1					2.8		2.7		0.8
DR Program Total	1.5	0.2	-	-	-	3.0		1.1		0.7
DSM Portfolio Total (EE + ES + DR)	53.1	172.0	120.7	1,502	26.9	3.0	2.0	1.4	2.9	2.0

Currency is expressed in 2023 dollars. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

¹⁸ Estimates are based on current electricity emissions intensity and reductions in emissions intensity in accordance with Nova Scotia Greenhouse Gas Emissions Regulations emissions caps, §4 (1)

^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission, distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of benefits).

^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes only.

^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. PAC excluding carbon is provided for informational purposes only.

^e Reflects E1's planned participation by low-income customers. Numbers are a subset of Residential Efficient Product Rebates, Existing Residential, Efficient Product Rebates (BNI), and Direct Installation.

Table 11: 2024 Settlement Plan Investment and Savings, by Program Component

2024	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
							incl. carbon	excl. carbon	incl. carbon	excl. carbon
Residential (Res) Energy Efficiency (EE) Programs										
Efficient Product Rebates	4.6	10.1	10.4	91	1.1	-	1.1	0.7	2.2	1.4
Appliance Retirement	1.0	0.7	1.2	5	0.2		0.9	0.6	0.6	0.4
Instant Savings	3.5	9.4	9.2	86	1.0		1.1	0.7	2.7	1.7
Existing Residential	22.5	55.3	58.8	433	10.2	-	1.6	1.1	2.5	1.8
Efficient Product Installation	3.3	7.7	11.6	69	1.6		2.3	1.5	2.3	1.5
Affordable Multi-family Housing	1.3	3.9	1.9	34	0.6		1.2	0.9	2.9	2.1
Home Energy Assessment	3.9	22.4	8.6	172	4.3		2.0	1.6	5.7	4.4
Green Heat	2.2	9.9	3.6	64	2.7		1.5	1.2	4.5	3.5
Mi'kmaw Home Energy Efficiency Project	1.2	1.1	0.5	10	0.2		0.9	0.6	0.9	0.6
Affordable Single-Family Homes	8.2	6.0	2.9	55	0.8		0.7	0.5	0.7	0.5
Residential Behaviour	2.2	4.3	29.8	30	0.0		1.9	1.0	1.9	1.0
New Residential	0.0	0.0	0.0	0	0.0	-	-	-	-	-
Low-Income Participation ^e	11.7	14.3	12.8	127	2.2		1.0	0.7	1.2	0.8
Res EE Programs Subtotal	27.1	65.3	69.3	524	11.4	-	1.5	1.0	2.4	1.7
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs										
Efficient Product Rebates	7.4	56.6	35.3	526	6.7	-	3.8	2.5	7.6	5.1
Custom Incentives	8.4	36.5	25.7	313	5.1	-	2.5	1.7	4.4	2.9
Custom	7.5	35.8	23.1	308	4.8		2.6	1.8	4.8	3.2
Strategic Energy Management & Energy Management Information Systems	0.9	0.7	2.7	5	0.3		0.9	0.5	0.8	0.4
Direct Installation	6.6	19.7	12.2	178	2.5	-	2.2	1.5	3.0	2.0
Low-Income Participation ^e	0.2	1.5	1.0	14	0.3		2.8	1.9	7.7	5.2
BNI EE Programs Subtotal	22.4	112.8	73.3	1,016	14.3	-	2.9	2.0	5.0	3.4
Total EE Programs	49.5	178.1	142.6	1,540	25.6	-				
Enabling Strategies (ES)										
Education & Outreach	1.5									
Development & Research	1.5									
Other Enabling Strategies	1.6									
Total ES	4.5									
EE Portfolio Total (EE + ES)	54.0	178.1	142.6	1,540	25.6	-	2.0	1.4	3.3	2.3
Demand Response (DR) Program										
Residential Demand Response	2.2					2.9		0.8		0.6
BNI Demand Response	1.3					7.1		2.7		0.8
DR Program Total	3.5	0.9	-	-	-	10.0		1.1		0.7
DSM Portfolio Total (EE + ES + DR)	57.5	179.0	142.6	1,540	25.6	10.0	2.0	1.4	2.8	2.0

Currency is expressed in 2024 dollars. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2024 present values of each year's costs and lifetime benefits.

^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission, distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the

avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of benefits).

^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes only.

^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. PAC excluding carbon is provided for informational purposes only.

^e Reflects E1's planned participation by low-income customers. Numbers are a subset of Residential Efficient Product Rebates, Existing Residential, Efficient Product Rebates (BNI), and Direct Installation.

Table 12: 2025 Settlement Plan Investment and Savings, by Program Component

2025	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
							incl. carbon	excl. carbon	incl. carbon	excl. carbon
Residential (Res) Energy Efficiency (EE) Programs										
Efficient Product Rebates	5.6	11.6	10.9	105	1.1	-	1.1	0.7	2.1	1.4
Appliance Retirement	1.1	0.7	1.2	5	0.2		0.9	0.6	0.6	0.4
Instant Savings	4.5	11.0	9.7	100	1.0		1.1	0.7	2.4	1.6
Existing Residential	23.6	58.0	60.6	456	10.2	-	1.6	1.2	2.5	1.8
Efficient Product Installation	4.2	10.0	13.4	92	1.6		2.4	1.5	2.4	1.5
Affordable Multi-family Housing	1.4	3.9	1.9	34	0.6		1.2	0.9	2.9	2.1
Home Energy Assessment	3.9	22.8	8.6	172	4.3		2.0	1.6	5.8	4.5
Green Heat	2.2	10.2	3.6	64	2.7		1.5	1.2	4.5	3.7
Mi'kmaw Home Energy Efficiency Project	1.3	1.1	0.5	10	0.2		0.9	0.6	0.9	0.6
Affordable Single-Family Homes	8.4	6.1	2.9	55	0.8		0.7	0.5	0.7	0.5
Residential Behaviour	2.2	3.9	29.8	30	0.0		1.8	1.0	1.8	1.0
New Residential	0.0	0.0	0.0	0	0.0	-	-	-	-	-
Low-Income Participation ^e	12.1	15.2	13.4	135	2.1		1.0	0.7	1.3	0.9
Res EE Programs Total	29.1	69.6	71.6	561	11.3	-	1.5	1.0	2.4	1.7
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs										
Efficient Product Rebates	8.4	62.2	38.5	572	7.2	-	3.7	2.6	7.4	5.1
Custom Incentives	8.6	37.8	26.8	322	5.1	-	2.5	1.7	4.4	3.0
Custom	7.7	37.1	24.2	317	4.8		2.6	1.8	4.8	3.3
Strategic Energy Management & Energy Management Information Systems	0.9	0.7	2.7	5	0.3		0.9	0.5	0.7	0.5
Direct Installation	6.8	20.5	12.6	183	2.6	-	2.2	1.6	3.0	2.1
Low-Income Participation ^e	0.2	1.6	1.0	15	0.3		2.8	2.0	7.7	5.3
BNI EE Programs Subtotal	23.8	120.4	77.9	1,077	15.0	-	2.9	2.0	5.1	3.5
Total EE Programs	52.9	190.1	149.5	1,639	26.3	-				
Enabling Strategies (ES)										
Education & Outreach	1.5									
Development & Research	1.5									
Other Enabling Strategies	1.6									
Total ES	4.6									
EE Portfolio Total (EE + ES)	57.5	190.1	149.5	1,639	26.3	-	2.0	1.4	3.3	2.3
Demand Response (DR) Program										
Residential Demand Response	2.8					7.1		0.8		0.6
BNI Demand Response	2.1					10.7		2.7		0.8
DR Program Total	5.0	1.8	-	-	-	17.9		1.1		0.7
DSM Portfolio Total (EE + ES + DR)	62.5	191.9	149.5	1,639	26.3	17.9	2.0	1.4	2.9	2.1

Currency is expressed in 2025 dollars. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2025 present values of each year's costs and lifetime benefits.

^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission, distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of benefits).

^cTRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes only.

^dPAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life. PAC excluding carbon is provided for informational purposes only.

^e Reflects E1's planned participation by low-income customers. Numbers are a subset of Residential Efficient Product Rebates, Existing Residential, Efficient Product Rebates (BNR), and Direct Installation.

As with prior DSM Plans, this Settlement Plan has been developed for planning and cost-effectiveness testing purposes and is not an implementation plan. E1 is committed to adapting the activities and services outlined in the Settlement Plan, as needed, to respond to changing technological and market conditions, and to ensure Performance Targets are met cost-effectively and within the approved investment amount. For DR programs, a level of collaboration with NS Power is a requirement. Any costs related to NS Power supporting these programs are not included in E1's investment.

3.2 SETTLEMENT PLAN – RATE CLASS ALLOCATIONS

Planned rate class expenditures for the Settlement Plan are provided in Table 13, below, by year and by Plan period.

Table 13: Rate Class Expenditures by Year

Rate Class	Settlement Plan Expenditures (\$ million) by Rate Class			
	2023	2024	2025	2023-2025
Residential/Charitable (2,3,4)	28.2	31.7	34.5	94.3
Small General (10)	2.7	2.8	3.0	8.5
General Demand (11)	13.8	14.3	15.4	43.4
Large General (12)	2.4	2.4	3.1	7.9
Small Industrial (21)	1.8	1.8	1.9	5.6
Medium Industrial (22)	1.0	1.1	1.1	3.2
Large Industrial (23,25)	2.2	2.3	2.4	6.9
Municipal (24)	1.0	1.0	1.1	3.1
Unmetered (999)	0.03	0.03	0.03	0.09
Total	53.1	57.5	62.5	173.0

Includes EE, DR (E1 costs only), and Enabling Strategies investments

3.3 SETTLEMENT PLAN – COST-EFFECTIVENESS

The cost effectiveness results for the Settlement Plan are shown below as part of Table 14, which provides cost effectiveness results associated with the Settlement Plan, for both the TRC and PAC tests.

The TRC test forms the decision-making screen for cost effectiveness testing methodology employed in Nova Scotia, which takes place at the NSUARB program level. This means that each program is required to pass a cost-effectiveness screening test at the program component level. In the Settlement Plan, the following are NSUARB programs:

- Efficient Product Rebates (Residential);
- Existing Residential;
- New Residential;
- Efficient Product Rebates (BNI);
- Custom Incentives;
- Direct Installation; and
- Demand Response.

E1 believes the PAC test provides another valuable perspective on cost-effectiveness because it represents only the utility costs and benefits. Cost effectiveness results for each sector by program are provided in Table 14.

Table 14: 2023-2025 Settlement Plan Cost Effectiveness Results by Program

2023-2025 Settlement Plan	Total Resource Cost (TRC) Test ^a	Program Administrator Cost (PAC) Test ^b
Residential Energy Efficiency (EE) Programs		
Efficient Product Rebates	1.1	2.2
Existing Residential	1.5	2.4
New Residential	2.6	4.8
<i>Residential Low-Income</i>	<i>1.0</i>	<i>1.2</i>
Residential Sector Total	1.5	2.4
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs		
Efficient Product Rebates	3.7	7.5

2023-2025 Settlement Plan	Total Resource Cost (TRC) Test ^a	Program Administrator Cost (PAC) Test ^b
Custom Incentives	2.5	4.3
Direct Installation	2.2	3.0
<i>BNI Low-Income</i>	2.8	7.6
BNI Sector Total	2.9	5.0
EE Portfolio Total (includes Enabling Strategies and EE Programs)	2.0	3.3
Demand Response (DR) Program		
DR Program Total	1.1	0.7
Settlement Plan Total (EE + DR + ES)	2.0	2.9

Portfolio total cost effectiveness tests are calculated using the sum of each year's present value of benefits and costs.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life.

Key observations associated with the Settlement Plan cost-effectiveness are:

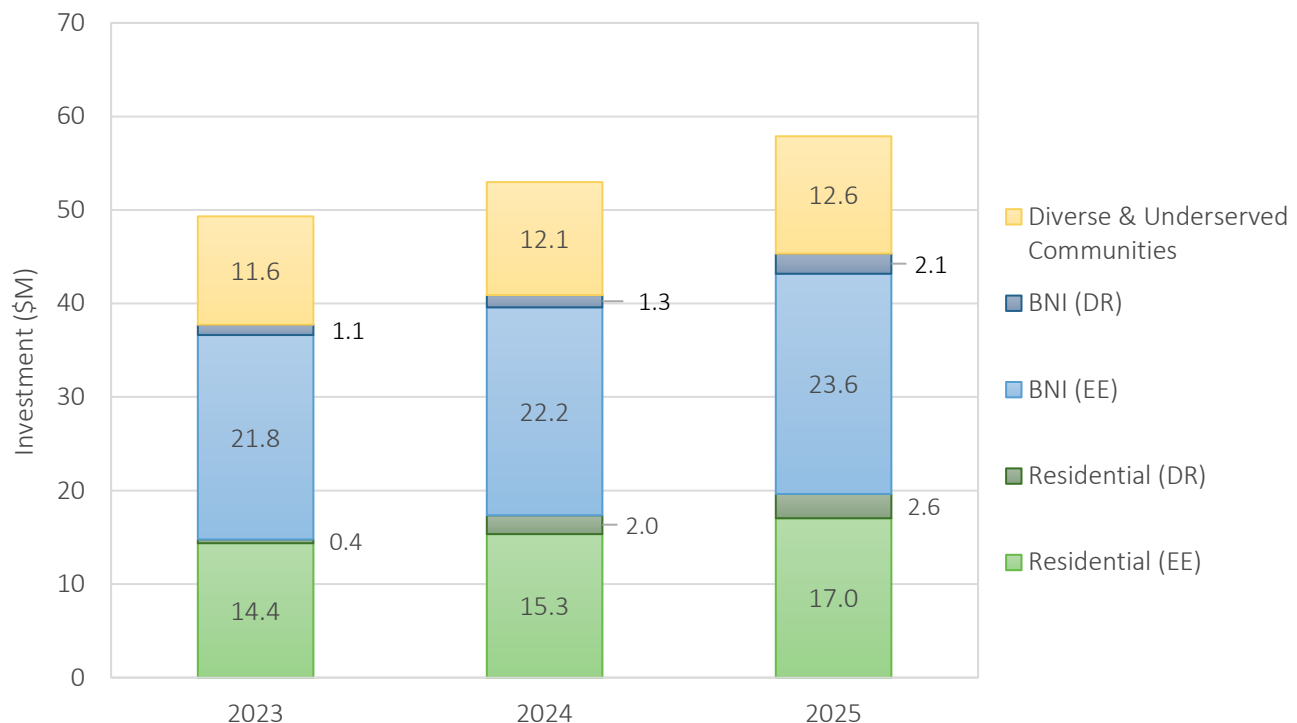
- Affordable Single-family Homes and Mi'kmaw Home Energy Efficiency Project program components do not pass TRC. These are dedicated low-income, and diverse or underserved communities, program components, which are expected to lower TRC values, when compared to market-rate DSM programs.
- E1's BNI sector has a moderately higher TRC value when compared to the Residential sector – this is largely attributable to savings opportunities in the BNI sector generally producing more benefits per dollar invested.
- Efficient Product Rebates (BNI) program component possesses the highest TRC and PAC test results at a program component level within the portfolio.
- The New Residential program possesses a high TRC value, owing to both the long measure lives of the program measures as well as the fact that the modelled treatment only reflects completions with existing 2022 customers.
- For energy efficiency programming, PAC test results are typically higher when compared to TRC test results, owing to the inclusion of incremental costs (total cost difference between the standard and efficient option) in the TRC test results, while the PAC only contains the incentive portion of incremental costs. This situation is reversed for certain Direct Installation measures.

The Settlement Plan programs are cost-effective for both the Residential and BNI sectors with passing benefit/cost ratios across all programs. The DR Program is also shown above, with a cost effectiveness ratio of 1.1. This information is presented above in Table 14.

3.4 SETTLEMENT PLAN – CUSTOMER GROUPS & SEGMENTS

To ensure the Settlement Plan represents all Nova Scotians and is accessible for all to enjoy the benefits of energy efficiency, the Settlement Plan was designed with customers top of mind during the design phase, as described in Section 2.2.2. Customer segments were developed to ensure each grouping's unique needs were captured in the design to allow E1 to tailor programs and services around these segments. Settlement Plan investments in each of three major groups: Residential, BNI, and Diverse & Underserved Communities (i.e. low-income and Mi'kmaw), for 2023, 2024, and 2025, is illustrated in Figure 12 below.

Figure 12: 2023-2025 Settlement Plan Investment Summary, by Year



Diverse & underserved communities includes EE & DR Residential sector low-income, EE Business, Non-Profit & Institutional sector low-income, and Mi'kmaw Home Energy Efficiency Project investments.

E1 focused its portfolio design objectives to provide access to all market segments, and particularly within four major categories: residential, small business, commercial & industrial, and diverse & underserved communities. Investments in these categories demonstrate to participants the potential energy and

demand savings opportunities they have in common with other participants. These four major categories of customer segments are further described in Table 15, below, along with the dedicated program components and other supports available for this segment in the Settlement Plan.

Table 15: Major Categories of Customer Segments, Dedicated Program Components & Other Support

Category	Description of Target Segment	Dedicated Program Components	Other Support & Resources
Residential	Homeowners/tenants of new and existing single-family homes including: • multi-unit • detached homes • semi-detached • row houses • individual condo units • mobile homes	• Appliance Retirement • Instant Savings • Efficient Product Installation • Green Heat • Home Energy Assessment • Residential Behaviour • Residential Demand Response	• Energy Solutions Advisors • EPP network • online resources (efficiency tools, tips, and guides) • home shows & trade shows • Switch newsletter • market transformation efforts for new residential homes through builder education and training
Small Business	E1 defines eligible small businesses as a business that the total energy consumption of the facility is less than 350,000 kWh annually, or approximately \$3,800 or less per year on electricity costs.	• Small Business Energy Solutions (SBES) • Business Energy Rebates • BNI Demand Response	• dedicated Business Development Manager (BDM) for the small business sector • Energy Solutions Advisors • EPP network • online resources (efficiency tools, tips, and guides) • Switch newsletter • training • trade shows
Commercial & Industrial	Commercial includes a variety of commercial buildings, such as: • retail • office buildings • municipal, provincial, and federal buildings • hospitals • multi-unit residential buildings (MURBs) • school boards • hospitality • transportation • universities and colleges	• Custom – Retrofit, Building Optimization, and New Construction • Business Energy Rebates • BNI Demand Response	• Onsite Energy Managers (OEMs) • BDM dedicated to specific commercial buildings • EPP network • pay-for-performance • commercial kitchen rebates • commercial benchmarking pilot • trade shows

Category	Description of Target Segment	Dedicated Program Components	Other Support & Resources
Commercial & Industrial	• other commercial sectors		
	Industrial includes businesses that produce goods within Nova Scotia, such as: • aquaculture • agriculture • paper • lumber • mining • fabrications • food/beverage processing • other manufacturing sectors	• Strategic Energy Management & Energy Management Information Systems • Custom – Retrofit, Building Optimization and New Construction • Business Energy Rebates • BNI Demand Response	• Industrial Energy Managers (IEMs) – large industrial performance-based incentives • OEMs • EPP network • BDM dedicated to industrial sectors • compressed air audit • trade shows
Diverse & Underserved Communities	Nova Scotians on incomes below the provincial median are faced with challenges when it comes to energy efficient upgrades. Many low-income households are not likely to have the funds to implement energy efficiency measures without assistance and therefore tend to spend more of their income on energy. This segment can experience limited access to information that could help with understanding the benefits of participating in energy efficiency programs.	• Mi'kmaw Home Energy Efficiency Project • Affordable Single-family Homes • Affordable Multi-family Housing & Non-Profit Organizations	• Appliance Replacement/ Retirement • Efficient Product Installation • Residential Behaviour • Small Business Energy Solutions • Business Energy Rebates • Energy Solutions Advisors • EPP network • Diverse & Underserved Communities initiative • roving OEM for Mi'kmaw communities • Mi'kmaw Engagement Officer • BDM dedicated to Mi'kmaw and diverse communities

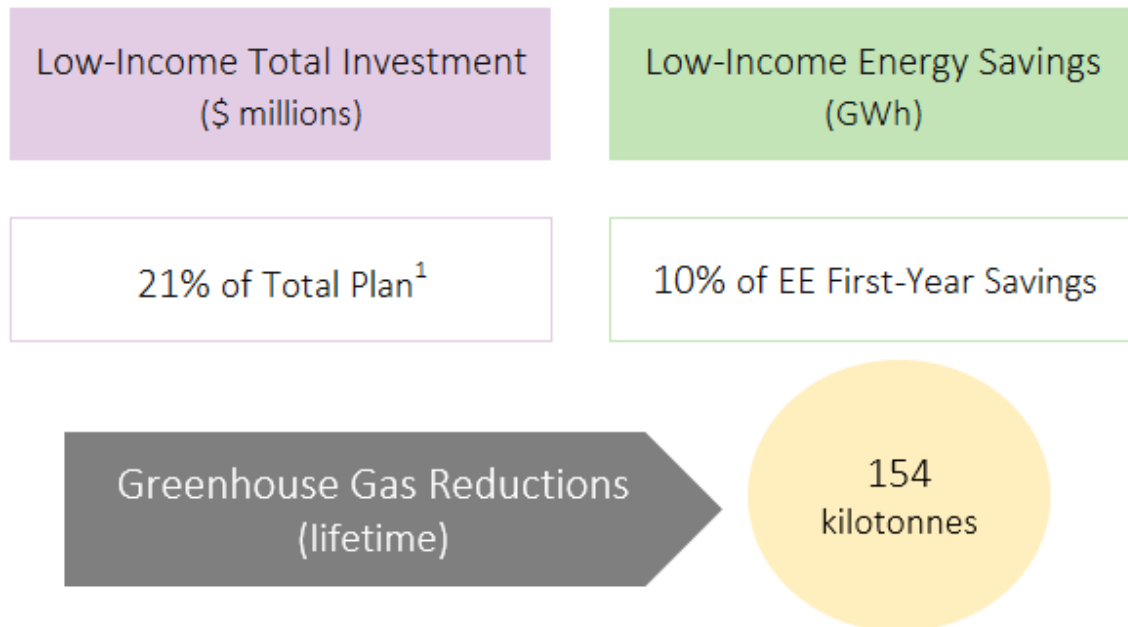
A priority in the design of E1's Settlement Plan was accessible and available program opportunities that ensure the energy efficiency improvement of homes and businesses in low-income, underserved, and diverse communities. The section below further describes details of specific enhancements in support of greater equity and accessibility.

3.4.1 DIVERSE & UNDERSERVED COMMUNITIES

E1 focused on strengthening the support provided to diverse and underserved communities in the Settlement Plan. Expanding investments in DSM for these customer groups is an important way to ensure their participation in energy efficiency programs to realize the resulting energy bill savings. The Settlement

Plan further increases equity and accessibility to low-income Nova Scotian's by increasing investment for this customer group to 21% of total Plan investment, outlined in Figure 13.

Figure 13: 2023-2025 Low-Income Investment, First-Year Energy Savings & Greenhouse Gas Reductions



¹ Total Plan investment includes EE and DR program investments and Enabling Strategies investment

The pursuit of energy-related benefits through the delivery of energy efficiency services for diverse and underserved communities, as highlighted in Figure 13 reduce the energy burden experienced by income eligible households. In addition there are other important benefits such as workforce development and partnerships, improved health outcomes, and improved home comfort that can be achieved through energy efficiency efforts.

E1 included focused support for Mi'kmaw communities for the first time in the 2020-2022 DSM Plan. Building on the success of Mi'kmaw Home Energy Efficiency Project, which was included as a new program component in the 2020-2022 DSM Plan, the Settlement Plan expands support for Mi'kmaw communities in the following areas.

- Participation in other residential program opportunities, such as:
 - Efficient Product Installation
 - Green Heat
 - Home Energy Assessment

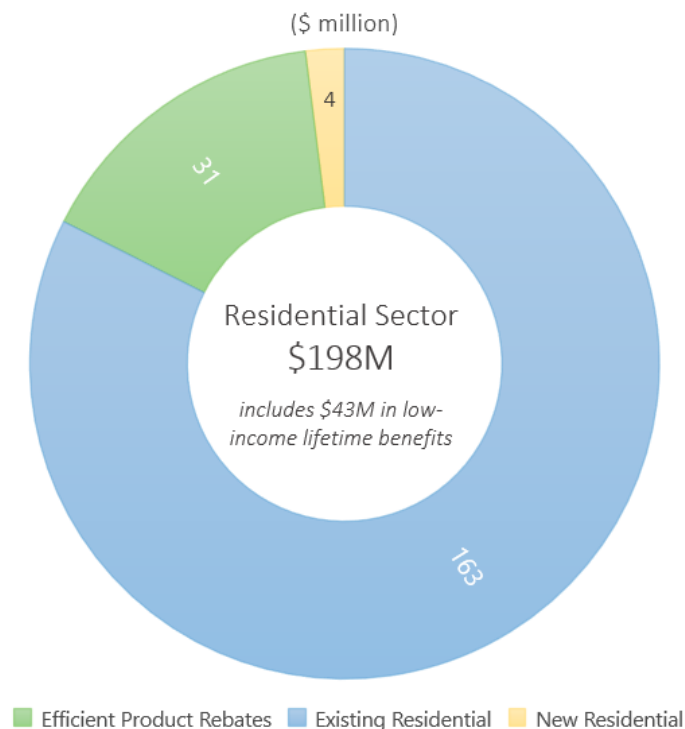
-
- 1 • Focused engagement and outreach through the Diverse Communities initiative, including:
 - 2 ○ Mi'kmaw Engagement Officer
 - 3 ○ Diversification training with the EPP network through partnerships with Immigrant Services
 - 4 Association of Nova Scotia (ISANS) Workforce Culture Training Program, workshops, and
 - 5 training sessions to help EPP network members understand the benefits of hiring a diverse
 - 6 workforce and the resources available to help navigate hiring and retaining a diverse
 - 7 workforce.
 - 8 • Development of opportunities for Onsite Energy Management and Business Development, such as:
 - 9 ○ Roving OEM for Mi'kmaw communities to support new partnership opportunities towards
 - 10 GHG, fuel reduction, and energy security through:
 - 11 ▪ Energy Management Plans that set energy savings targets for each community, identify
 - 12 champions in the communities, and identify project opportunities
 - 13 ▪ Identify program funding for energy efficiency projects
 - 14 ▪ Engineering support for New Construction design process (Energy Manager acts as
 - 15 "owners engineer")
 - 16 • Business Development Manager for Mi'kmaw communities to support the identification of
 - 17 opportunities for participation in other E1 business programs and help customers throughout the
 - 18 participation process. Other business program opportunities include:
 - 19 ○ Custom
 - 20 ○ Small Business Energy Solutions
 - 21 ○ Business Energy Rebates

4. RESIDENTIAL PROGRAMS & SERVICES

For over a decade, E1's residential programs have provided Nova Scotia customers bill savings, improved comfort, and protection from energy cost increases. Over that decade, E1 introduced a new dedicated offer for Mi'kmaw communities, designed a pathway to higher performing new homes, and delivered programs that promote the adoption of high performing energy efficient technologies that transformed the Nova Scotian market, such as cold climate heat pumps and light-emitting diode (LED) lighting products.

The Settlement Plan will allow E1 to continue delivering cost-effective energy savings benefits for Nova Scotia's residential customers. The Settlement Plan pursues enhanced approaches to the delivery of programs and activities to better help customers navigate the complex upgrade choices available in today's energy market. Over the past three years, E1 has further refined its focus on understanding customers, their values, and how best to work with them to support the adoption of energy efficient measures in their homes. To provide the highest level of benefits to customers, E1 will continue to evolve and improve its services and delivery during the 2023-2025 DSM Plan period. As shown in Figure 14, the Settlement Plan outlines an extensive portfolio of program offerings in the 2023-2025 DSM plan period indicating lifetime benefits for the residential sector.

Figure 14: Residential Sector Lifetime Benefits



E1's Settlement Plan's residential sector provides a comprehensive portfolio of services that benefit all residential, low-income, and diverse and underserved communities. As the Nova Scotia electricity efficiency market continues to mature, some opportunities become increasingly saturated. E1 will evolve program and service offerings by taking advantage of new technologies and customer data to achieve energy savings from larger, more complex projects that are often more expensive to implement but produce higher, and longer lasting, energy savings.

This evolution is reflected in the Settlement Plan, which supports the adoption of a variety of energy efficient products and services in areas such as the building envelope, space heating equipment, and domestic water heating. The Settlement Plan demonstrates an increased shift towards non-lighting measures and builds on steps being taken in 2022. Enhancements for the Residential sector in the Settlement Plan, described in the next section, focus on the following key areas:

- decreasing reliance on energy savings from lighting;
- increasing accessibility to programs and services; and
- increasing types of benefits delivered by DSM (i.e. including system-peak demand reduction).

The Settlement Plan offers three Residential sector programs and ten program components, as presented in Table 16, below.

Table 16: Settlement Plan – Residential Sector Offerings

Program	Program Component	Target Market Segment	Delivery Approach	Enhancements in Settlement Plan	Section Reference
Residential Efficient Product Rebates	Appliance Retirement	Residential (renters, homeowners, landlords, low-income & Mi'kmaw)	Turn-key service	• Continued support	Section 4.1.2.1
	Instant Savings	Residential (renters, homeowners)	Point-of-sale discounts	• Expanded ENERGY STAR® Measures List	Section 4.1.2.2
Existing Residential	Affordable Multi-family Housing & Non-Profit Organizations	Residential (landlords)	Facilitated* and financial incentives	• Prescriptive Rebates	Section 4.2.2.1

Program	Program Component	Target Market Segment	Delivery Approach	Enhancements in Settlement Plan	Section Reference
Existing Residential	Efficient Product Installation	Residential (renters, homeowners, landlords, low-income)	Turn-key service	Electrician-Installed Measures	Section 4.2.2.2
	Mi'kmaw Home Energy Efficiency Project	Residential (band-owned homes)	Turn-key service	Continued support	Section 4.2.2.3
	Green Heat	Residential (renters, homeowners, landlords)	Post-purchase rebates	Continued support	Section 4.2.2.4
	Home Energy Assessment	Residential (homeowners, landlords)	Facilitated* and financial incentives	Continued support	Section 4.2.2.5
	Affordable Single-family Homes	Residential (homeowners, low-income)	Turn-key service	This is a new program component	Section 4.2.2.6
	Residential Behaviour	Residential (homeowners, renters, landlords)	Energy-use feedback	This is a new program component	Section 4.2.2.7
New Residential	New Home Construction	Residential (homeowners, builders)	Facilitated* and financial incentives	Wind down of existing program component in light of changes to the residential new construction market	Section 4.3

*Facilitated is defined as providing customers with assistance in identifying energy efficiency opportunities and guidance on implementation to satisfy program requirements.

To deliver the benefits of these programs to customers, E1 must intervene in various ways to overcome barriers to participation. Through marketing, education, awareness campaigns, partnerships, and expert technical support, E1 will increase customer awareness of services available, the benefits they provide to customers, and how individuals can participate.

4.1 RESIDENTIAL EFFICIENT PRODUCT REBATES PROGRAM

4.1.1 OBJECTIVES

Objectives of the Residential Efficient Product Rebates program include:

- make energy-efficient products more accessible to Nova Scotians across all income levels and geographic locations;
- increase customer and retailer awareness of opportunities to increase their energy efficiency;
- increase demand for energy efficient products;
- increase the availability of energy-efficient products at retailers;
- increase customer and retailer awareness of the benefits of energy efficient products, particularly the lesser-known non-lighting products;
- encourage the adoption of energy efficient technologies and increase market participation for the purchase and installation of energy efficient products;
- remove old, inefficient appliances from the Nova Scotia electricity system and reduce the availability of used, inefficient appliances; and
- help customers achieve energy savings and power bill reductions.

Table 17, below, provides a summary of the participant, industry, environmental, and strategic DSM Portfolio benefits of the Residential Efficient Product Rebates program as designed in the Settlement Plan.

Table 17: Summary of Benefits – Efficient Product Rebates (Residential)

Participant Benefits	Industry Benefits	Environmental Benefits	Strategic DSM Portfolio Benefits
• utility bill savings and improved home comfort • improved access and reduced financial barriers to adoption of energy efficient products • improved safety and longevity of products	• increased retailer sales and customer satisfaction • leverages other program initiatives (old appliances replaced through other programs are retired through Appliance Retirement) • increased market awareness of energy efficiency opportunities	• reduced GHG emissions due to reductions in energy consumption • reduced adverse environmental impacts of appliance retirements through environmentally friendly decommissioning and recycling • reduced waste of inefficient baseline products with shorter useful lives, in particular incandescent and fluorescent lamps • alignment with Provincial and Federal incentives for reduced GHG emissions	• easy-to-participate with low-cost options for renters, landlords, and homeowners during peak seasons, such as renovation and home purchasing periods • increased public awareness of energy efficiency opportunities, driving participation in other E1 programs and services • establishes market channels that ease the expansion of future customer offers • supports adoption of codes and standards

4.1.2 OVERVIEW

Residential Efficient Product Rebates is a well-established program in Nova Scotia and has been operating as part of the E1 portfolio since 2010. The Residential Efficient Product Rebates program provides residential customers access to financial incentives for consumer products through retail channels and to retire and/or replace old inefficient appliances. The Residential Efficient Product Rebates program is comprised of two program components:

- Appliance Retirement; and
- Instant Savings.

Instant Savings on energy-efficient products has been operating since 2009¹⁹ and Appliance Retirement has been operating since 2010. Each of these program components is further described in the sections that follow.

4.1.2.1 APPLIANCE RETIREMENT PROGRAM COMPONENT

The Appliance Retirement program component helps residential customers responsibly dispose of old, inefficient appliances through a turn-key service approach. This service will pick up and responsibly recycle working, but less-efficient, home appliances such as refrigerators, freezers, and air conditioners from customers across the province. Customers receive a financial incentive for each retired appliance. Appliance Retirement also currently includes a free replacement service for qualified low-income customers participating in the HomeWarming program. As part of the replacement service, the older appliance is removed and retired, and a new energy efficient appliance is delivered and installed.

Table 18 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Appliance Retirement program component in the Settlement Plan.

Table 18: Three-Year Summary of the Appliance Retirement Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
2023 Total	1.0	1.2	0.2	2,973

¹⁹ In 2009, NS Power offered a DSM program offering instant rebates program on energy efficient products. The responsibility and accountability for DSM administration transferred to Efficiency Nova Scotia effective October 1, 2010.

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
<i>Low-income</i>	<i>0.01</i>	<i>0.01</i>	<i>0.002</i>	<i>33</i>
2024 Total	1.0	1.2	0.2	2,973
<i>Low-income</i>	<i>0.01</i>	<i>0.01</i>	<i>0.002</i>	<i>33</i>
2025 Total	1.1	1.2	0.2	2,987
<i>Low-income</i>	<i>0.01</i>	<i>0.01</i>	<i>0.002</i>	<i>33</i>
Target Market	Includes all residential customers including low-income, diverse communities, and renter customer groups.			
Market Barriers	• <u>Affordability</u>: the cost difference between efficient products and less efficient products can create a participation barrier. • <u>Accessibility</u>: coordinating appliance purchases, deliveries, and retirements can be overly burdensome and result in participant's deferring the removal or replacement of inefficient appliances. • <u>Lack of trust</u>: some potential participants do not trust a free service. • <u>Lack of information</u>: lack of familiarity with energy efficient products and appliances.			
Key Components	• Turn-key, ease-of-access delivery model • No-cost appliance replacements for diverse and underserved communities • Environmentally friendly retirement of old, inefficient products			
Measures Promoted	• refrigerators • freezers • window air conditioning			
Program Component History & Highlights	• 2010 – pilot launched in Halifax Regional and Cape Breton Regional Municipality only • 2011 – pilot expanded to province-wide program component • 2012 – limited-time (1-year) pilot offer launched to offer customized incentives for replacing inefficient large-scale appliances with new ENERGY STAR® qualified appliances using a full-service (i.e. one-stop purchase, delivery, and decommissioning) delivery model • 2012 – temporarily offered participants the choice between incentives in the form of cash rebates or Air Miles rewards; the Air Miles promotion ended in 2014 • 2015 – integrated appliance replacements for low-income participants of the HomeWarming service, at no-cost to participants • 2020 – in response to the global COVID-19 pandemic, Appliance Retirement shifted to provide contactless pickup and delivery • 2021 – continued to offer contactless pick-ups and hosted several community drop-off events to provide communities with standardized times and locations for retirements of smaller-scale appliances Highlights:			

Program Component History & Highlights	• 56,354²⁰ – the number of inefficient appliances safely recycled through Appliance Retirement since 2012 • 95% – the portion of retired appliance components that are completely recycled through this program component

Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical Tables for additional detail.

4.1.2.2 INSTANT SAVINGS PROGRAM COMPONENT

The Instant Savings program component focuses on purchases made through participating retail stores across Nova Scotia by offering customers point-of-sale rebates on eligible energy efficient products. Products typically include LED lighting products, thermostats, appliances, controls, and other consumer goods. Instant Savings provides point-of-sale rebates for energy efficient products and technologies in two formats: year-round incentives (offered on select products), and seasonal incentive campaigns (offered twice annually during spring and autumn).

E1 partners with national and independent retailers, as well as non-traditional retailers such as electricians and installers, to deliver rebates. Historically, incentives have been made available at more than 200 retail locations throughout Nova Scotia. In addition to point-of-sale rebates, Instant Savings also collaborates with retailers to increase customer engagement through in-store events where trained energy ambassadors demonstrate products, educate consumers on their use, and discuss the benefits of energy efficiency.

Table 19 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Instant Savings program component in the Settlement Plan.

Table 19: Three-Year Summary of the Instant Savings Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
2023 Total	2.9	9.7	1.0	135,933
<i>Low-income</i>	<i>0.03</i>	<i>0.11</i>	<i>0.01</i>	<i>1,509</i>

²⁰ M10056, Exhibit 1, EfficiencyOne 2020 DSM Evaluation Reports, Final Report, March 26, 2021. See Residential Efficient Product Rebates Program, 2020 DSM Evaluation, March 31, 2021, page 5.

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
2024 Total	3.5	9.2	1.0	99,019
<i>Low-income</i>	<i>0.04</i>	<i>0.10</i>	<i>0.01</i>	<i>1,099</i>
2025 Total	4.5	9.7	1.0	79,234
<i>Low-income</i>	<i>0.05</i>	<i>0.11</i>	<i>0.01</i>	<i>879</i>
Target Market	Residential customers that purchase products through retail channels, including owner-occupied and rental properties. Key partnerships include major retailers such as Costco, Home Depot, and a variety of appliance, lighting, heating, and home improvement manufacturers and distributors.			
Market Barriers	• <u>Affordability</u>: the cost difference between efficient products and less efficient products can create a participation barrier. • <u>Awareness</u>: some potential participants may not be aware of the benefits of energy-efficient products. • <u>Accessibility & short decision period</u>: replacement of failing products or equipment can occur quickly resulting in lost opportunities. In the absence of widely available, discounted energy efficient products, consumers are likely to choose inefficient alternatives. • <u>Lack of information</u>: lack of knowledge around how to choose and install energy efficient products and appliances.			
Key Components	• Partnerships with national and local retailers • Product incentives to shift market behaviours • Advertising, education, and promotion			
Measures Promoted	• LED lighting – non-A-Series LED lighting • LED fixtures – recessed downlight fixtures and integrated fixtures – with and without motion sensors • dimmer switches – with and without indoor motion sensors • indoor and outdoor motion sensors • low-flow showerheads • programmable thermostats and smart thermostats for electric heating • smart power bars, power bars with built-in timers, and outdoor heavy-duty timers • clotheslines and outdoor drying racks • room air purifiers • ENERGY STAR® certified clothes washers and clothes dryers • dehumidifiers • variable speed pool pumps • air source heat pump hot water heaters			

Program Component History & Highlights	• 2009 – first pilot launched (Efficient Lighting Products) followed by several pilot adjustments (2010 – Power Down, 2011 – Plug into Savings, 2012 – Retail Markdown); all of which offered rebates primarily through seasonal campaigns in the spring and autumn • 2009 to 2011 – pilots continued with a heavy focus on lighting, specifically screw-in Compact Fluorescent Lamps (CFLs), and then shifted toward LEDs with their introduction in 2011 • 2012 – the establishment of the full-scale program component, known as Instant Savings, and the development of the consistent delivery model that has remained unchanged • 2014 – the program component began offering year-round rebates on eligible refrigerators and clothes washers • 2018 – year-round rebate offerings expanded to include other products such as smart thermostats and dehumidifiers • 2019 – eligible products under Instant Savings shifted as a result of gradual market evolution; most notably changing with the discontinuation of rebates on all A-series LED lamps beginning in 2019. E1 introduced online retailers to their list of participating retailers. • 2020 – in response to the global COVID-19 pandemic, online retailers became a heavier focus for future program delivery efforts; ENERGY STAR® certified clothes dryers were also added in 2020, along with the removal of ENERGY STAR® certified refrigerators Highlights: • 3,103,100²¹ – number of efficient products purchased through Instant Savings since 2015
Enhancements in 2023-2025	Expansion of the number of residential eligible ENERGY STAR® certified products available for point-of-sale rebates. New products may include ENERGY STAR® certified dishwashers, bathroom fans, air conditioning units, and kitchen range hoods. The introduction of these measures will reduce cost and access barriers, helping Nova Scotians adopt energy efficient products for their homes. The Instant Savings program component began exploring an expanded online rebate presence, in response to the global COVID-19 pandemic, and increased activity in online retail marketplaces. The Settlement Plan will continue these efforts and may include exploration of an online vendor rebate model in the 2023-2025 Plan period.

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2 Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical
3 Tables for additional detail.

²¹ M10056, Exhibit 1, EfficiencyOne 2020 DSM Evaluation Reports, Final Report, March 26, 2021. See Residential Efficient Product Rebates Program, 2020 DSM Evaluation, March 31, 2021, page 29.

4.1.3 IMPLEMENTATION STRATEGY

4.1.3.1 PROGRAM DELIVERY

The Residential Efficient Product Rebates program uses both a self-serve and turn-key delivery approach to help residential customers make smart energy choices through the retirement and/or replacement of inefficient appliances and the purchase of high-efficiency consumer goods.

The Appliance Retirement program component uses a delivery agent approach for service delivery. The service to customers provided by the delivery agent includes the management of all aspects of appointment booking, pick-ups, transportation, and delivery/decommissioning of the appliances.

The Instant Savings program component engages a delivery agent for encouraging and recruiting retailers to participate, managing relationships with participating retailers, delivering in-store customer engagement events, and providing retailer training on energy-efficient products and additional E1 services. In 2023-2025 Plan period, E1 will continue to explore and grow its online point-of-sale rebate offering through the Instant Savings program component. This may include recruiting large-scale online marketplaces such as Amazon, expanding online rebate options through existing in-store retailers, and exploration of an online marketplace or web-based portal.

4.1.3.2 MARKETING STRATEGY

The marketing strategy for Appliance Retirement will focus on enhancing a customer's quality of life through non-energy benefits (convenient, hassle-free pick up and recycling) with the rebate promoted as a secondary message (through targeted advertising). The objective to increase the number of appliances retired is achieved through integrated marketing campaigns, which may include digital and social media, out-of-home (billboard, truck wraps), radio, and direct mail. To increase program participation across Nova Scotia, the marketing strategy is to reach out to potential participants through various platforms to encourage appliance retirement.

The marketing strategy for Instant Savings is to increase awareness and drive customers to retail locations to realize the benefits of energy efficient products. The marketing plan is designed to encourage customers to purchase a range of energy efficient products during campaign periods (or, for some products, year-round) to make their homes more efficient and comfortable, to incent customers to purchase energy

efficient products by removing the price barrier, and to ensure customers can easily recognize eligible products in-stores. It includes the following tactics:

- development of point-of-purchase materials and in-store signage;
- customer engagement events and materials;
- training for efficiency ambassadors; and
- E1 website updates.

Media promotion may include radio remotes, radio and television commercials, digital advertising, electronic billboard advertising, cross-promotion with other E1 programs (e.g. postcards delivered to customers in Appliance Retirement & Efficient Product Installation), and social media.

4.1.3.3 QUALITY ASSURANCE

The Residential Efficient Product Rebates program has a quality assurance framework, which may include remote or in-person retailer site visits (during both campaign and non-campaign periods), random customer record review, appliance metering, appliance internal temperature testing, and customer satisfaction surveys.

4.1.4 PERFORMANCE INDICATORS

Performance indicators for the Residential Efficient Product Rebates program are provided in Table 20, below.

Table 20: 2023-2025 Residential Efficient Product Rebates Performance Indicators

Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Lifetime Unit Cost (\$/kWh) ^d
					incl. carbon	excl. carbon	incl. carbon	excl. carbon		
2023	4.0	10.9	83	1.2	1.1	0.7	2.3	1.4	138,906	0.05
2024	4.6	10.4	91	1.1	1.1	0.7	2.2	1.4	101,991	0.05
2025	5.6	10.9	105	1.1	1.1	0.7	2.1	1.4	82,221	0.05
Total	14.1	32.3	279	3.5	1.1	0.7	2.2	1.4	323,118	0.05

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021. Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of individual products rebated through Appliance Retirement and Instant Savings.

^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

4.1.4.1 LOW-INCOME PERFORMANCE INDICATORS

Low-Income performance indicators for the Residential Efficient Product Rebates program are provided in Table 21, below.

Table 21: 2023-2025 Residential Efficient Product Rebates Low-Income Performance Indicators

Year	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Participation (products) ^a
2023	0.1	0.9	0.01	1,542
2024	0.1	1.0	0.01	1,132
2025	0.1	1.2	0.01	913
Total	0.4	3.1	0.04	3,587

Columns may not add correctly, due to rounding.

^a The number of individual products rebated through Instant Savings and Appliance Retirement

4.1.5 PROGRAM ALTERNATIVES

The Residential Efficient Product Rebates program shows no difference in the Alternate Scenario when compared to the Settlement Plan. Therefore, there is no variance in the Residential Efficient Product Rebates program between the Settlement Plan and Alternate Scenario. Table 22, below, presents this difference for the Residential Efficient Product Rebates program.

Table 22: 2023-2025 Residential Efficient Product Rebates Performance Indicators – Comparison of Settlement Plan and Alternate Scenario

Scenario	Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Lifetime Unit Cost (\$/kWh) ^d
						incl. Carbon	excl. Carbon	incl. Carbon	excl. Carbon		
Settlement	2023	4.0	10.9	83	1.2	1.1	0.7	2.3	1.4	138,906	0.05
	2024	4.6	10.4	91	1.1	1.1	0.7	2.2	1.4	101,991	0.05
	2025	5.6	10.9	105	1.1	1.1	0.7	2.1	1.4	82,221	0.05
	Total	14.1	32.3	279	3.5	1.1	0.7	2.2	1.4	323,118	0.05
Alternate	2023	4.0	10.9	83	1.2	1.1	0.7	2.3	1.4	138,906	0.05
	2024	4.6	10.4	91	1.1	1.1	0.7	2.2	1.4	101,991	0.05
	2025	5.6	10.9	105	1.1	1.1	0.7	2.1	1.4	82,221	0.05
	Total	14.1	32.3	279	3.5	1.1	0.7	2.2	1.4	323,118	0.05
Variance from Settlement	2023	0%	(0%)	0%	0%	0%	0%	0%	0%	(0%)	0%
	2024	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2025	0%	0%	0%	0%	0%	0%	0%	0%	(0%)	0%
	Total	0%	0%	0%	0%	(1%)	(1%)	0%	(0%)	(0%)	0%

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of individual products rebated through Appliance Retirement and Instant Savings.

^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

4.2 EXISTING RESIDENTIAL PROGRAM

4.2.1 OBJECTIVES

Objectives of the Existing Residential program include:

- increase customer awareness of cost-effective options to increase their energy efficiency;
- improve the energy performance of residential dwellings within Nova Scotia;
- improve homeowners understanding of their home's energy efficiency and performance;
- help property owners improve the efficiency of low-income housing stock to reduce energy poverty and maintain affordable housing in Nova Scotia;
- significantly reduce energy use in homes across all Mi'kmaw communities;
- reduce the burden of heating and energy costs for low-income Nova Scotians;
- achieve lasting energy and system-peak demand savings;
- provide customer engagement to support the broader transition to wide-scale adoption of energy efficiency products and behaviours across Nova Scotia; and
- encourage the adoption of equipment that reduces utility peak demand.

Table 23, below, provides a summary of the participant, industry, environmental, and strategic DSM Portfolio benefits of the Existing Residential program as designed in the Settlement Plan.

Table 23: Summary of Benefits – Existing Residential

Participant Benefits	Industry Benefits	Environmental Benefits	Strategic DSM Portfolio Benefits
• utility bill savings and improved home comfort • greater program benefits for residents	• increased sales of energy efficient products • improved industry capacity and	• reduced GHG emissions due to reductions in energy consumption	• strengthened relationships and partnerships with Mi'kmaw communities • easy access to coordinated component offers (e.g. Efficient

Participant Benefits	Industry Benefits	Environmental Benefits	Strategic DSM Portfolio Benefits
at the highest risk of energy poverty; limited rent increases for tenants through Affordable Housing Agreements • customized recommendations for reducing energy use based on consumption patterns and building characteristics • increased energy literacy and dedicated support for diverse and underserved communities	expertise in building envelope and deep retrofit services • greater awareness of available energy efficiency expertise and services in the Nova Scotia market • local economic development opportunities through use of local installers and contractors	• alignment with Provincial and Federal incentives for reduced GHG emissions • increased resident awareness of opportunities to reduce their carbon footprint	Product Installations and in-home energy assessments) • cross-promotion between components and creation of potential for more complex future initiatives such as demand response • Residential Behaviour program component may provide opportunities for cost-efficiencies with behavioural demand response and may provide a foundational platform from which future low-cost DSM offers can be launched • supports codes and standards through incentivizing space and water heating systems above baseline standards, driving increased demand for the highest-efficiency products

4.2.2 OVERVIEW

The Existing Residential program has been operating in various forms since Efficiency Nova Scotia was established. The Existing Residential program provides residential customers with access to technical and financial assistance to identify, assess and implement energy efficiency and system-peak demand reduction upgrades. The Existing Residential program is comprised of the following seven components:

- Affordable Multi-family Housing and Non-Profit Organizations;
- Efficient Product Installation;
- Mi'kmaw Home Energy Efficiency Project;
- Green Heat;
- Home Energy Assessment;
- Affordable Single-family Homes; and
- Residential Behaviour.

Each of these program components is further described in the sections that follow.

4.2.2.1 AFFORDABLE MULTI-FAMILY HOUSING & NON-PROFIT ORGANIZATIONS

The Affordable Multi-family Housing and Non-Profit Organizations program component was developed specifically to help low-income renters, non-profits that provide shelter, and community services to low-income residents, access the benefits of energy efficiency through reduced utility bills and stable rents. This program component offers energy audits and project management support for energy-efficient upgrades of low-income housing units, combined with technical and financial assistance, to help building owners make energy efficient upgrades.

Table 24 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Affordable Multi-family Housing and Non-Profit Organizations program component in the Settlement Plan.

Table 24: Three-Year Summary of the Affordable Multi-family Housing & Non-Profit Organizations Program Component

Annual Plan ²²	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation	
				(products)	(projects)
2023 Total	1.3	1.9	0.6	133	42
2024 Total	1.3	1.9	0.6	133	42
2025 Total	1.4	1.9	0.6	133	42
Target Market	Offers property owners of existing residential facilities that provide affordable housing in Nova Scotia access to energy efficiency audits, contractors, and rebates for the completion of energy efficiency projects. These include for-profit and non-profit rental housing, shelters, transition houses, housing co-operatives, and non-profit services such as food banks and community outreach centres.				
Market Barriers	• <u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments). • <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. • <u>Resources</u>: lack of time/human resources for project management, contractor management, upgrade implementation. • <u>Split incentive</u>: when landlords are not paying for utilities (specifically heating), they are often not motivated to implement energy efficiency upgrades to the building and/or equipment.				
Key Components	• Energy audits for affordable multi-family housing units and non-profit organizations				

²² Affordable Multi-family Housing & Non-Profit Organizations is a 100% low-income program component; all figures are low-income figures.

Key Components	• Project management support through energy efficiency upgrades • Improved efficiency, comfort, and performance of low-income housing stock
Measures Promoted	Upgrades focus on building envelope, as well as measures such as: • heating systems (e.g. mini-split heat pumps) • fenestration (e.g. windows) • building envelope upgrades, such as draft-proofing and insulation • domestic hot water heating systems • ventilation upgrades, such as heat recovery ventilators • common-area lighting, on occasion
Program Component History & Highlights	• 2016 – pilot launched using a similar framework as SBES and specifically targeted at landlords renting affordable housing units • 2017 – initial pilot efforts did not generate strong participation results, leading to support from the Province of Nova Scotia to build on the DSM pilot and help overcome barriers in this target market • 2018 – continuing as a pilot through the SBES program component, the pilot adapted in response to feedback identifying a need for higher incentives, more time to complete projects, and additional project management support • 2019 – launched as a standalone program component, Affordable Multi-family Housing, under Existing Residential • 2020 – the program component expanded its scope to incorporate non-profit organizations providing shelter, in addition to its support for low-income renters • 2021 – pilot launched to test prescriptive rebate stream, which is further described in the Enhancements section Highlights: • 88%²³ – the growth in participants served by the Affordable Multi-family Housing & Non-Profit Organizations program component in 2020, over 2019, despite periods of suspended audits due to the global COVID-19 pandemic
Enhancements in 2023-2025	Continuing to build on the prescriptive rebate stream, introduced in the 2020-2022 DSM Plan, to help address barriers to participation for property owners with smaller (e.g. 1-3 units) buildings requiring more efficient space or water heating systems. The prescriptive stream is, by design, a complementary offering to the standard comprehensive stream. This stream will introduce new ways to access rebates for heat pumps, primarily mini-splits, and heat pump water heater measures – improving the heating system efficiency of the affordable housing stock in Nova Scotia.

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- 2 Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical
- 3 Tables for additional detail.

²³ M10056, Exhibit 1, EfficiencyOne 2020 DSM Evaluation Reports, Final Report, March 26, 2021. See Existing Residential Program, 2020 DSM Evaluation, March 31, 2021, page 114.

4.2.2.2 EFFICIENT PRODUCT INSTALLATION

The Efficient Product Installation program component conducts low-cost energy efficient upgrades for homeowners and renters, at no-cost. During a home visit, qualified installers provide free installation of energy efficient products such as lighting, domestic hot water measures, smart technologies and controls, and other electricity-saving equipment. Efficient Product Installation offers the opportunity to engage directly with customers during the home visit. Installers demonstrate energy efficient products and their benefits, educate customers on energy efficient practices and technologies, and promote the value of more comprehensive assessments and upgrades for the dwelling.

Table 25 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Efficient Product Installation program component in the Settlement Plan.

Table 25: Three-Year Summary of the Efficient Product Installation Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
2023 Total	3.1	11.2	1.7	236,016
<i>Low-income</i>	<i>0.57</i>	<i>3.92</i>	<i>0.62</i>	<i>83,025</i>
2024 Total	3.3	11.6	1.6	221,507
<i>Low-income</i>	<i>0.62</i>	<i>4.08</i>	<i>0.60</i>	<i>77,921</i>
2025 Total	4.2	13.4	1.6	214,277
<i>Low-income</i>	<i>0.78</i>	<i>4.72</i>	<i>0.58</i>	<i>75,377</i>
Target Market	Serves all types of residential dwellings in Nova Scotia, including single detached homes, semi-detached homes/duplexes, townhouses, mobile/mini homes, rental housing, and other multi-family residences such as apartments and condominiums.			
Market Barriers	• <u>Affordability</u>: the cost difference between efficient products and less efficient products can create a participation barrier. • <u>Awareness</u>: some potential participants may not be aware of the benefits of energy-efficient products. • <u>Lack of trust</u>: some potential participants do not trust a free service. • <u>Lack of information</u>: lack of knowledge about how to select and install energy efficient products. • <u>Resources</u>: lack of time/human resources for project management, contractor management, and upgrade implementation. • <u>Split incentive for rentals</u>: when either landlords or renters are not paying for utilities, they are often not motivated to implement energy efficiency upgrades.			
Key Components	• Turn-key ease-of-access delivery model			

Key Components	• No-cost products and installation • Environmentally friendly product recycling • In-home, personalized, education and awareness
Measures Promoted	• LED lighting – A-series and non-A series, decorative, and specialty lamps • LED nightlights and holiday lights • pipe insulation • hot water tank wraps • kitchen and bathroom faucet aerators • low-flow showerheads • thermostatic shower valves • smart power bars • clotheslines (seasonal) • air sealing kits – foam gaskets, door sweeps, window air sealing, and door weatherstripping • <u>NEW</u> – smart thermostats for electric baseboard heating • <u>NEW</u> – dimmer switches and motion sensors • <u>NEW</u> – domestic hot water heater controls
Program Component History	• 2011 – pilot launched providing an additional no-cost service under several other program components and replacing primarily incandescents with screw-in Compact Fluorescent Lighting (CFLs) • 2012 – pilot established as a standalone program component, Residential Direct Install, focusing on communities with a high percentage of low-income residents and participants of other program components • 2014 – program component expanded to serve all Nova Scotians, province-wide; known as the “light exchange program” the component shifted from installation of CFLs and began installing LEDs to replace incandescent bulbs • 2017 – merged with former program component, Rental Properties and Condominiums, the newly-titled Efficient Product Installation component expanded to provide a complete, consistent service to residents of all home types and sizes • 2018 – introduced its first of many annual season-based promotional product installations, swapping incandescent holiday lights with LEDs, which was a continuation from the previous community-based Holiday Light Exchange efforts conducted through Enabling Strategies; followed by several adjustments to measure offerings in response to market transformation in the residential lighting sector • 2019 – added a second seasonal promotion period, offering clotheslines in spring/summer, to drive interest and participation in the well-established service; expanded to provide direct installation of basic weather- and draft-proofing measures, such as door sweeps, weatherstripping, and foam gaskets
Enhancements in 2023-2025	Electrician-installed measures that enable automated energy use reduction and may provide the opportunity for E1 to integrate its EE and DR programming for cost efficiencies and ease of participation. New measures may include occupancy sensors, lighting controls, and smart thermostats for electric heating systems.

Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical Tables for additional detail.

4.2.2.3 MI'KMAW HOME ENERGY EFFICIENCY PROJECT

The Mi'kmaw Home Energy Efficiency Project program component is a whole-home retrofit service offered to customers at no-cost. Available to band-owned homes in Mi'kmaw communities, the Mi'kmaw Home Energy Efficiency Project provides a fully project-managed service inclusive of energy efficiency assessments and systematic improvements to building envelopes (including air tightness, insulation, windows, and doors), and heating and ventilation systems to improve the energy efficiency and comfort of their homes. Where possible, E1's delivery agents hire qualified Mi'kmaw and community-preferred contractors to complete the work.

Upgrades delivered through this program component also include draft proofing, insulation, energy efficient space and water heating equipment, and appliance replacements (offered exclusively to eligible low-income and Mi'kmaw customers participating in the Mi'kmaw Home Energy Efficiency Project, HomeWarming, and Affordable Single-family Homes program components).

Table 26 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Mi'kmaw Home Energy Efficiency Project program component in the Settlement Plan.

Table 26: Three-Year Summary of the Mi'kmaw Home Energy Efficiency Project Program Component

Annual Plan ²⁴	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation	
				(products)	(homes)
2023 Total	1.2	0.5	0.2	130	118
2024 Total	1.2	0.5	0.2	130	118
2025 Total	1.3	0.5	0.2	130	118
Target Market	Band-owned homes in Mi'kmaw communities.				
Market Barriers	• <u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments).				

²⁴ Mi'kmaw Home Energy Efficiency Project is a 100% low-income program component; all figures are low-income figures.

Market Barriers	• <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. • <u>Resources</u>: lack of time/human resources for project management, contractor management, upgrade implementation. • <u>Split incentive</u>: without incorporating benefits for band offices and participants, Housing Managers often face competing priorities and limited financial resources to implement energy efficiency upgrades to the building and/or equipment.
Key Components	• Opportunity to engage Mi'kmaw communities through a community-driven, tailored solution to address their specific circumstances and interests • No-cost home energy assessments and energy efficiency upgrades tailored to the home • Improved efficiency, comfort, and performance of existing residential housing stock • In-home, personalized, education and awareness
Measures Promoted	Upgrades focus on building envelope, as well as measures such as: • heating systems – mini-split heat pumps • programmable or smart thermostats • window and/or door replacements • drain water heat recovery systems • air source heat pump water heaters • ventilation upgrades – bathroom fans and heat recovery ventilation • carbon monoxide detectors • appliance replacements – refrigerators, freezers, dehumidifiers, and clothes dryers
Program Component History & Highlights	• 2018 – the First Nations Home Energy Efficiency pilot launched as phase 1 of a multi-phase pilot aimed at reaching participants across all Mi'kmaw communities • 2019 – phase 2 of the pilot commenced with the start of upgrades in participant homes • 2020 – with the approval of the 2020-2022 DSM Resource Plan, the pilot became a standalone program component and was renamed Mi'kmaw Home Energy Efficiency Project Highlights: • 91²⁵ – number of Mi'kmaw participants in the DSM-portion of this program component since its launch

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- 2 Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical
- 3 Tables for additional detail.

²⁵ M10056, Exhibit 1, EfficiencyOne 2020 DSM Evaluation Reports, Final Report, March 26, 2021. See Existing Residential Program, 2020 DSM Evaluation, March 31, 2021, page 103.

4.2.2.4 GREEN HEAT

The Green Heat program component is externally marketed as Heating System Rebates. Through this offering, Nova Scotians can apply for post-purchase rebates for high-efficiency space and water heating system upgrades. The program component encourages the installation of highly efficient heating systems, as well as heating systems fueled by renewable resources, such as solar and biomass.

Table 27 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Green Heat program component in the Settlement Plan.

Table 27: Three-Year Summary of the Green Heat Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
2023 Total	2.2	3.6	2.7	3,406
2024 Total	2.2	3.6	2.7	3,408
2025 Total	2.2	3.6	2.7	3,408
Target Market	Property owners of residential dwellings in Nova Scotia, including single detached homes, semi-detached homes/duplexes, townhouses, mobile/mini homes, and condominiums.			
Market Barriers	• <u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation). • <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. • <u>Short decision period</u>: replacement of failing space or water heating equipment can occur quickly resulting in lost opportunities if the efficient product is not purchased.			
Key Components	• Product incentives for major space and water heating upgrades to shift market behaviour • Ease-of-access to rebates within 180-days of purchase and installation • Improved efficiency, comfort, and performance of existing residential housing stock			
Measures Promoted	• heat pump systems – ductless mini-split heat pumps, central/ducted heat pumps, air-to-water heat pumps, and geothermal heat pumps • biomass systems – wood or pellet stoves and fireplace inserts, wood or pellet boilers, and wood or pellet central/ducted forced air furnaces • solar thermal air-to-air systems • domestic water heating systems – three-element (low-peak demand) water heaters, residential domestic hot water timers, and solar thermal domestic water heaters			
Program Component History & Highlights	• 2011 – pilot, Fuel Substitution, launched initially aimed at promoting fuel switching to natural gas heating systems • 2012 – pilot established as a standalone program component			

Program Component History & Highlights	• 2013 – modified initial natural gas fuel switching scope to focus on switching to fuel derived from renewable sources; program component retitled to Green Heat • 2015 – incorporated solar thermal rebates that were formerly offered under a separate program component and began rebating ductless mini-split heat pumps, resulting in significant increases to participation • 2017 – revised delivery model from pre-approval to post-purchase, mail-in rebates in response to market barriers to entry and participation • 2020 – launched new system peak demand measures, like electric thermal storage, and topped up rebates for the locational DSM pilot in Kentville, referred to as the Klondike Pilot; heat pump water heaters were removed due to low participation levels and this measure was added to the Instant Savings program component • 2021 – in response to persistent impacts of the global COVID-19 pandemic, increased the post-purchase application eligibility period from 90- to 180-days Highlights: • 13,632²⁶ – efficient space and water heating systems installed through the Green Heat program component since 2012

Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical Tables for additional detail.

4.2.2.5 HOME ENERGY ASSESSMENT

The Home Energy Assessment program component was developed specifically to help homeowners make informed choices about energy efficient and deep savings upgrades to their homes. Home energy evaluations, coupled with the interaction of a Natural Resources Canada (NRCAN) registered Energy Advisor (EAs) and prioritized, tailored recommendations, educate and inform homeowners who may not otherwise be aware of their home's upgrade potential. Deep energy savings measures, such as building envelope improvements, and the installation of efficient heating systems, can deliver significant energy savings to customers.

Personalized recommendations and access to the trained expertise of EAs, helps homeowners confidently identify, navigate, and invest in energy saving upgrades that improve the energy efficiency and comfort of their homes. Financial incentives, in the form of rebates or financing, are offered to help homeowners overcome the financial barrier to implementing otherwise costly retrofits. Homeowners learn about the

²⁶ M10056, Exhibit 1, EfficiencyOne 2020 DSM Evaluation Reports, EfficiencyOne, Final Report, March 26, 2021. See Existing Residential Program, 2020 DSM Evaluation, March 31, 2021, page 34.

energy efficiency of their home, the fundamentals of building systems, and are empowered to conduct upgrades that provide them with both financial savings and increased home comfort.

Table 28 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Home Energy Assessment program component in the Settlement Plan.

Table 28: Three-Year Summary of the Home Energy Assessment Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation	
				(products)	(homes)
2023 Total	3.9	8.6	4.3	96	1,827
2024 Total	3.9	8.6	4.3	97	1,827
2025 Total	3.9	8.6	4.3	96	1,827
Target Market	Property owners of residential dwellings in Nova Scotia, including single detached homes, semi-detached homes/duplexes, townhouses, mobile/mini homes, and condominiums.				
Market Barriers	• <u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments). • <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. • <u>Lack of understanding</u>: homeowners may struggle to find qualified contractors to perform energy efficiency upgrades and/or be unsure about how to move forward and have upgrades completed. • <u>Short decision period</u>: replacement of failing space or water heating equipment can occur quickly resulting in lost opportunities if the efficient product is not purchased. • <u>Uncertainty</u>: homeowners may be reluctant to enroll if they do not understand the costs, benefits, and appropriateness of efficiency measures for their home specifically.				
Key Components	• Financing and stackable incentives for major home upgrades to shift market behaviour • Ease-of-access to home energy assessments and energy efficiency recommendations tailored to the home • In-home, personalized, education and awareness • Improved efficiency, comfort, and performance of existing residential housing stock				
Measures Promoted	• building envelope upgrades – ceiling/attic insulation, foundation/basement insulation including basement slab and foundation headers, exterior wall insulation, exposed floor insulation, and air sealing • heat pump systems – ductless mini-split heat pumps, central/ducted heat pumps, air-to-water heat pumps, and geothermal heat pumps • biomass systems – wood or pellet stoves and fireplace inserts, wood or pellet boilers, and wood or pellet central/ducted forced air furnaces • domestic water heating systems – residential domestic hot water timers, and air source heat pump water heaters				

Measures Promoted	• electric thermal storage systems – room units and central hydronic or forced air furnaces • heat recovery ventilation systems • windows, doors, and skylights • air sealing
Program Component History & Highlights	• 2000s – incentives offered through the federal government for building envelope upgrades in the EnerGuide for Existing Homes program • 2010 – E1 inherits the Existing Homes service from Conserve Nova Scotia and NS Power (acting as interim DSM Administrator) • 2012 – significant adjustments to newly titled Home Energy Assessment program component, including scaling back eligible measures to focus solely on building envelope upgrades; until 2012, when the Residential Direct Installation program component was established, this program component also included an optional stream providing no-cost direct install of efficient products • 2013 – introduced a financing option, which provided the option between rebates or low-interest financing of home upgrades • 2015 – reduced participant cost of assessments, bringing the total cost to participate to \$99 + HST; the program component also introduced rebates for space and water heating equipment, and re-structured rebates to encourage participants to achieve deeper energy savings through rebate top-ups for bundled upgrades • 2017 – Natural Resources Canada implemented a revised EnerGuide rating system, which rated home efficiency on its energy use (in gigajoules, GJ) rather than the previous 0-100 rating; this new scale meant that 0 GJ was the highest efficiency rating (previously an EnerGuide score of 100 was the highest efficiency rating) • 2018 – in response to customer feedback, the program component underwent a redesign to simplify the navigation of its delivery model and rebates for participants • 2020 – launched new system peak demand measures, like electric thermal storage, and topped up rebates for the locational DSM pilot in Kentville, referred to as the Klondike Pilot; a virtual audit stream was also piloted that coincided with the suspension of in-home visits due to the global COVID-19 pandemic • 2021 – increased the cost of assessments by in response to increased EAs scope due to the launch of the federal Greener Homes initiative, bringing the total cost to participate to \$199 + HST – the additional \$100 upfront cost is rebated to participants installing an eligible Greener Homes measure Highlights: • 12,285²⁷ – number of participants the Home Energy Assessment program component has helped improve the efficiency of their existing home since 2012

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2 Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical
3 Tables for additional detail.

²⁷ M10056, Exhibit 1, EfficiencyOne 2020 DSM Evaluation Reports, Final Report, March 26, 2021. See Existing Residential Program, 2020 DSM Evaluation, March 31, 2021, page 36.

4.2.2.6 AFFORDABLE SINGLE-FAMILY HOMES

This is a new program component being re-introduced under the Existing Residential Program in the Settlement Plan. Re-introduction of this program component provides an opportunity to ensure equity of services for all participants (regardless of heat source), allows for transparency of program results for ratepayers through independent evaluation and reporting. The Affordable Single-family Homes program component provides a fully project managed, whole-home retrofit service at no-cost to income-qualified Nova Scotians. This effort will build on E1 experience delivering a similar program funded by the Province of Nova Scotia (to reduce non-electrical energy use), and through past E1 efforts to improve the energy efficiency of existing homes within income-eligible and low-income communities.

Upgrades delivered through this program component are inclusive of energy efficiency assessments and systematic improvements to building envelopes (including air tightness and insulation), energy efficient space heating and ventilation to improve the energy efficiency and comfort of participants' homes. Upgrades also include appliance replacements (offered exclusively to eligible low-income and Mi'kmaq customers participating in the Mi'kmaq Home Energy Efficiency Project, HomeWarming, and Affordable Single-family Homes program components).

Table 29 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Affordable Single-family Homes program component in the Settlement Plan.

Table 29: Three-Year Summary of the Affordable Single-family Homes Program Component

Annual Plan ²⁸	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation	
				(products)	(homes)
2023 Total	8.1	2.9	0.8	217	493
2024 Total	8.2	2.9	0.8	217	493
2025 Total	8.4	2.9	0.8	217	493
Target Market	Income-qualified (Statistics Canada Low-Income Cut-Off [LICO ²⁹] + 15% threshold) residential homeowners ³⁰ .				

²⁸ Affordable Single-family Homes is a 100% low-income program component; all figures are low-income figures.

²⁹ Statistics Canada. Table 11-10-0241-01 Low-income cut-offs (LICOs) before and after tax by community size and family size, in current dollars.

³⁰ LICO is regularly updated by Statistics Canada.

Market Barriers	• <u>Affordability</u>: lack of financial resources to cover upfront costs (product/equipment, installation, energy assessments). • <u>Awareness</u>: lack of information/knowledge about energy efficient technologies, upgrades, energy savings, and benefits. • <u>Resources</u>: lack of time/human resources for project management, contractor management, upgrade implementation. • <u>Lack of trust</u>: some potential participants do not trust a free service. • <u>Lack of information</u>: lack of familiarity with energy efficient products.
Key Components	• Opportunity to support low-income homeowners to address their specific circumstances • No-cost home energy assessments and energy efficiency upgrades • In-home, personalized, education and awareness • Improved efficiency, comfort, and performance of existing residential housing stock
Program Component History	• 2000s – programming offered through funding from the federal and provincial government, and NS Power, to provide building envelope upgrades (scope 1) and no-cost direct install measures (scope 2) for low-income households through the Residential Energy Affordability Program or also known as Low Income Households program • 2010 – E1 inherits the existing service for low-income households from Conserve Nova Scotia and NS Power (acting as interim DSM Administrator) • 2011 – introduced no-cost replacements of refrigerators and freezers to ENERGY STAR® certified models; launched a pilot providing the residential direct install scope of the program for two First Nations communities • 2012 – expanded the appliance scope of the service to provide new ENERGY STAR® certified dehumidifiers or replacements of inefficient working dehumidifiers; scope 1, no-cost direct install of efficient products, is decoupled from the Low-Income Homeowner Service and is instead delivered as a pre-assessment service through the Residential Direct Installation program component • 2015 – implementation of a new funding and management structure resulted in the transition of administration for electric homes to a third party; the program was rebranded to HomeWarming, and E1 continued its administration of the service for non-electrically heated homes only • 2020 – program administration of the HomeWarming service for both electric and non-electric low-income households transitioned back to E1, continuing to utilize the existing third-party for delivering this service to electric homes
Enhancements in 2023-2025	Affordable Single-family Homes is a new program component being re-introduced under the Existing Residential Program in the Settlement Plan. This effort will build on E1's experience delivering a similar program funded by the Province of Nova Scotia (to reduce non-electrical energy use), and through past E1 efforts to improve energy efficiency, safety, and comfort for low-income homeowners.

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2 Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical

3 Tables for additional detail.

4.2.2.7 RESIDENTIAL BEHAVIOUR

This is a new program component being re-introduced under the Existing Residential Program in the Settlement Plan (previously offered as Home Energy Report). The Residential Behaviour program component plans to provide tools and insights that will encourage Nova Scotians to adopt more energy-conscious behaviours and activities, leading to electricity savings and reduced utility bills. Through personalized and timely energy-use feedback, residential customers are empowered to make informed choices about their energy consumption behaviours and the E1 programs and services that can help support them along the way.

In the Settlement Plan, E1 will establish a home energy reporting initiative that builds on the foundation of E1's 2015 program and leverages advancements in energy reporting tools enabled through advanced metering infrastructure (AMI) data. AMI data provides near real-time energy consumption information and, when coupled with analytical tools and software, can provide meaningful insights that encourage Nova Scotians to shift behaviours.

The approval of NS Power's AMI³¹ capital project in 2018, and the expansion of NS Power's existing customer data sharing agreement with E1, opened the potential for future behavioural energy efficiency programming, leveraging AMI data, once meters were fully implemented and associated interval data came online. As of January 2022, NS Power reported that the large-scale implementation of AMI was substantially complete³², coinciding with the launch of NS Power's Time-Varying Pricing Pilot in November 2021. This large-scale deployment of AMI meters, and interval data availability, opens the door to low-cost demand side management program offerings through personalized and timely energy use feedback. The Residential Behaviour component may develop to include other feedback-based initiatives such as gamification through energy reduction challenges, and alerts and notifications providing at-a-glance energy saving recommendations and tips for residential customers.

Table 30 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Residential Behaviour program component in the Settlement Plan.

³¹ M08349 – Advanced Metering Infrastructure Project, was approved by the NSUARB on 11 June 2018.

³² M08349 – Advanced Metering Infrastructure Project, Fifth Semi-Annual Update, as filed 31 January 2022.

1 Table 30: Three-Year Summary of the Residential Behaviour Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (homes)
2023 Total	1.1	8.7	n/a	38,195
Low-income	0.13	0.96		4,240
2024 Total	2.2	29.8	n/a	131,379
Low-income	0.24	3.30		14,583
2025 Total	2.2	29.8	n/a	131,379
Low-income	0.24	3.30		14,583
Target Market	All residential customers who require assistance to make the best decisions around energy-use for their homes, including renters and owners.			
Market Barriers	• <u>Awareness</u>: lack of personal, relevant, and actionable insights about energy saving behaviours, products, and programs. • <u>Accessibility</u>: some potential participants may be unsure of the types of products or services available to reduce energy consumption, and how to get started. • <u>Short decision period</u>: in the absence of timely and personalized insights, potential participants may replace failing equipment without considering the efficient alternative. • <u>Lack of information</u>: lack of familiarity, information, or knowledge about energy efficient technologies, upgrades, energy savings and benefits.			
Key Components	• Detailed energy-use feedback • Personalized and timely home energy reports with calls-to-action			
Program Component History	• 2013 to 2015 – the Energy Savings Actions program launched as a limited-time (3-year) pilot, initially providing paper Home Energy Reports to 98,000 Nova Scotians and expanding, later the same year, to include web-based portal to all residential customers in the province			
Enhancements in 2023-2025	Residential Behaviour is a new program component being re-introduced under the Existing Residential Program, nearly one decade after E1’s initial offering in 2013-2015. This aligns with advances in energy-use feedback programming, the availability of AMI in Nova Scotia, and advances in analytical software and products available to deliver personalized, actionable insights. This new program component may also provide the opportunity for E1 to integrate its EE and DR programming for cost efficiencies and ease of participation.			

2

3 Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical

4 Tables for additional detail.

4.2.3 IMPLEMENTATION STRATEGY

4.2.3.1 PROGRAM DELIVERY

The Existing Residential Program leverages a variety of delivery approaches to help customers implement energy efficiency improvements in their home. These strategies include:

- turn-key direct installation service;
- after purchase mail-in rebates;
- mid-stream instant rebates;
- project management support;
- energy use feedback and personalized, actionable insights to encourage adoption of energy efficiency behaviours and practices; and
- whole building energy modelling and upgrade incentives.

The Affordable Multi-family Housing and Non-Profit Organizations program component is delivered in partnership with contracted energy auditors. An energy audit is performed on the building to identify energy efficiency opportunities specific to the building. Following the completion of upgrades, which could include increased insulation, energy efficient space and water heating equipment, appliances and lighting, participants receive rebates based on the implemented upgrades.

Efficient Product Installation is delivered in partnership with delivery agents that are responsible for booking installation appointments with customers, installing energy efficient products in place of inefficient alternatives, decommissioning and, where applicable, recycling the inefficient alternative products, demonstrating the products to participants, engaging with customers about energy efficiency, installer training and education, reporting and data collection, and marketing efforts.

The Mi'kmaw Home Energy Efficiency Project program component is delivered in partnership with Mi'kmaw Communities and two delivery agents. Housing Managers in each community select their participants based on need. Where possible, E1's delivery agents hire qualified Mi'kmaw-preferred contractors to complete the work. E1's delivery agents are responsible for:

- conducting the initial home energy assessment;
- proposing upgrades that are reviewed and approved by both E1 and the Housing Managers;
- hiring and managing contractors to implement the approved upgrades;

- conducting quality assurance site visits on all completed upgrades;
- conducting final home energy assessment; and
- providing documentation to E1.

Green Heat is delivered as an after-purchase rebate service. Participants may choose to submit an online, electronic mail, fax, or mail-in rebate application, at their convenience, following the installation of their new efficient equipment. This provides flexibility for customers, and also offers an opportunity for E1 to engage more directly with equipment providers to supply further information/training on relevant rebates.

The Home Energy Assessment program component is delivered with the support of NRCan licensed Service Organizations. Registered EAs complete an initial home energy assessment and provide the homeowner with a report containing tailored upgrade recommendations. Homeowners select and complete energy efficient upgrades. After completing upgrades, the EAs perform a final home energy assessment. Rebates provided to participants are based on the implemented upgrades.

The Affordable Single-family Homes program component will be delivered in partnership with delivery agent(s) licensed by NRCan as registered EAs. EAs will conduct pre-retrofit assessments, implement energy efficiency retrofits consisting largely of building envelope measures, and conduct post-retrofit assessments. E1's delivery agent(s) is responsible for:

- conducting an initial home energy assessment;
- proposing upgrades that are reviewed and approved by E1, and the homeowner;
- hiring and managing contractors to implement the approved upgrades;
- conducting quality assurance site visits on all completed upgrades;
- conducting the final home energy assessment; and
- providing documentation to E1.

The Residential Behaviour program component is expected to launch with the delivery of an opt-out home energy reporting service provided by paper, electronic mail, and/or online application. E1 is anticipating leveraging a third-party delivery model for this program component. As described in Section 4.2.2.7, Residential Behaviour may evolve over the 2023-2025 Plan period to include other feedback-based initiatives such as gamification through energy reduction challenges, and alerts and notifications providing at-a-glance energy saving recommendations and tips for residential customers.

4.2.3.2 MARKETING STRATEGY

The Existing Residential program marketing strategy will deliver integrated marketing campaigns by program component and market segment (e.g. home renovation, low-income, seniors), with a focus on providing more access to virtual education and support. E1's strategy will prioritize direct email marketing, as it is a highly cost-effective way to tailor communications to target market segments and is the preferred method of communication by both residents and businesses. E1 will continue to collaborate closely with its creative, digital, and media agency partners, EPP network members, and its program delivery agents to reach target markets and deliver effective program information and support. Specific tactics will include:

- contractor education and training;
- Delivery Agent education and training;
- industry event attendance and promotion;
- integrated media plans that include radio, TV, billboards, social media, streaming, search engine marketing, email marketing, events, and partnerships;
- in-store promotion and events;
- leveraging strategic partnerships; and
- community outreach and events.

4.2.3.3 QUALITY ASSURANCE

The Existing Residential program has an established quality assurance framework inclusive of random and targeted site visits, energy model file reviews and rebuilds, documentation review, and customer surveys.

4.2.4 PERFORMANCE INDICATORS

Performance indicators for the Existing Residential program are provided in Table 31, below.

Table 31: 2023-2025 Existing Residential Performance Indicators

Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Participation (homes) ^d	Participation (projects) ^e	Lifetime Unit Cost (\$/kWh) ^f
					incl. carbon	excl. carbon	incl. carbon	excl. carbon				
2023	20.9	37.3	403	10.3	1.5	1.1	2.4	1.7	239,998	40,633	42	0.05
2024	22.5	58.8	433	10.2	1.6	1.1	2.5	1.8	225,492	133,818	42	0.05
2025	23.6	60.6	456	10.2	1.6	1.2	2.5	1.8	218,261	133,818	42	0.05
Total	67.0	156.7	1,292	30.7	1.4	1.0	2.6	1.9	683,752	308,268	125	0.05

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of individual products rebated through Efficient Product Installation, Green Heat, Home Energy Assessment, Affordable Single-family Homes, Affordable Multi-family Housing & Non-Profit Organizations and Mi'kmaw Home Energy Efficiency Project.

^d The number of households completing upgrades through Home Energy Assessment, Affordable Single-family Homes, Affordable Multi-family Housing, and Mi'kmaw Home Energy Efficiency Project.

^e The number of projects completing upgrades through the Affordable Multi-family Housing & Non-Profit Organizations program component.

^f Lifetime unit cost is the quotient of lifetime energy savings and investment.

4.2.4.1 LOW-INCOME PERFORMANCE INDICATORS

Low-income performance indicators for the Existing Residential program are provided in Table 32, below.

Table 32: 2023-2025 Existing Residential Low-Income Performance Indicators

Year	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Participation (products) ^a	Participation (homes) ^b	Participation (projects) ^c
2023	10.2	120.4	2.2	83,505	4,851	42
2024	12.7	126.0	2.1	78,401	15,194	42
2025	13.3	134.2	2.1	75,858	15,194	42
Total	36.2	380.7	6.5	237,764	35,239	125

Columns may not add correctly, due to rounding.

^a The number of individual products rebated through Efficient Product Installation, the Affordable Multi-family Housing & Non-Profit Organizations, and Mi'kmaw Home Energy Efficiency Project.

^b The number of households completing upgrades through Mi'kmaw Home Energy Efficiency Project, Residential Behaviour, and Affordable Single-family Homes

^c The number of projects completing upgrades through the Affordable Multi-family Housing & Non-Profit Organizations program component.

4.2.5 PROGRAM ALTERNATIVES

The Existing Residential Program features several differences in the Alternate Scenario when compared to the Settlement Plan. The Efficient Product Installation program component does not contain a major initiative relating to smart thermostat and electrician-installed measures within the Alternate Scenario. As well, a lower level of Green Heat activity is featured within the alternate scenario across all DSM Plan years, owing a lower incentive approach for non-heat-pump-based measures. Lower levels of activity for Residential Behaviour are also present in the Alternate Scenario, as well as slightly lower levels of activity for Affordable Single-family Homes. Table 33, below, presents this difference for the Existing Residential program.

Table 33: 2023-2025 Existing Residential Performance Indicators – Comparison of Settlement Plan and Alternate Scenario

Scenario	Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Participation (homes) ^d	Participation (projects) ^e	Lifetime Unit Cost (\$/kWh) ^f
						incl. Carbon	excl. Carbon	incl. Carbon	excl. Carbon				
Settlement	2023	20.9	37.3	403	10.3	1.5	1.1	2.4	1.7	239,998	40,633	42	0.05
	2024	22.5	58.8	433	10.2	1.6	1.1	2.5	1.8	225,492	133,818	42	0.05
	2025	23.6	60.6	456	10.2	1.6	1.2	2.5	1.8	218,261	133,818	42	0.05
	Total	67.0	156.7	1,292	30.7	1.4	1.0	2.6	1.9	683,752	308,268	125	0.05
Alternate	2023	17.9	30.1	359	9.6	1.5	1.1	2.5	1.9	167,667	30,607	42	0.05
	2024	18.8	45.6	374	9.5	1.5	1.1	2.6	1.9	154,118	100,849	42	0.05
	2025	19.0	45.3	374	9.5	1.5	1.1	2.6	2.0	140,567	100,849	42	0.05
	Total	55.6	121.0	1,107	28.6	1.5	1.1	2.6	1.9	462,353	232,305	125	0.05
Variance from Settlement	2023	(15%)	(19%)	(11%)	(7%)	(0%)	1%	6%	7%	(30%)	(25%)	0%	(4%)
	2024	(16%)	(22%)	(14%)	(7%)	(2%)	0%	5%	7%	(32%)	(25%)	0%	(3%)
	2025	(20%)	(25%)	(18%)	(7%)	(3%)	(1%)	5%	8%	(36%)	(25%)	0%	(2%)
	Total	(17%)	(23%)	(14%)	(7%)	7%	7%	(0%)	0%	(32%)	(25%)	0%	(3%)

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of individual products rebated through Efficient Product Installation, Green Heat, Home Energy Assessment, Affordable Single-family Homes, Affordable Multi-family Housing & Non-Profit Organizations, and Mi'kmaw Home Energy Efficiency Project.

^d The number of households completing upgrades through Home Energy Assessment, Affordable Single-family Homes, Affordable Multi-family Housing & Non-Profit Organizations, and Mi'kmaw Home Energy Efficiency Project.

^e The number of projects completing upgrades through the Affordable Multi-family Housing & Non-Profit Organizations program component.

^f Lifetime unit cost is the quotient of lifetime energy savings and investment.

4.3 NEW RESIDENTIAL PROGRAM

4.3.1 OVERVIEW

The New Residential program provides residential home builders and new home market entrants access to technical assistance and financial incentives for the installation of energy efficiency upgrades during the design and early construction phases. The program consists of one program component, New Home Construction, which is further described in the section that follows. In the Settlement Plan, E1 will wind down activities in its New Residential program and refocus its support of new residential markets through the development of a market transformation approach. This approach is further described in Enabling Strategies under Section 7.

4.3.1.1 NEW HOME CONSTRUCTION PROGRAM COMPONENT

Since its adoption in 2011, the New Home Construction program component has provided support, education, and incentives to the building industry in Nova Scotia. The program has been successful at meeting targets established within the existing funding envelope and at moving the residential new construction market baseline. In Econoler's 2020 evaluation, it became evident that, with the increased popularity of heat pump installations in the residential new construction market, future savings adjustments were estimated to be reduced by at least 70% for the New Home Construction program component. The cost of delivering the existing program would therefore become too expensive to offer within a limited DSM budget. As a result, the program will be wound up and replaced with a new market transformation program within Enabling Strategies.

The New Home Construction program component provides financial incentives to participants based on whole home modelling. Typical energy efficiency upgrades recommended and implemented by program participants are increased insulation levels, energy efficient space heating and water heating equipment, and efficient ventilation systems.

Incentives are provided to reduce both the upfront costs of pre- and post-construction modelling, as well as for the implementation of comprehensive energy efficiency upgrades. Upgrade incentives are performance-based (corresponding to the size and configuration of the home) and are aligned with the achievement of consumption targets as compared to a home built to the Nova Scotia building code. Incentives are tiered and increase with increased energy savings to encourage homeowners and builders to build top performance homes such as passive homes, net zero ready, and net zero homes.

Table 34 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the New Home Construction program component in the Settlement Plan.

Table 34: Three-Year Summary of the New Home Construction Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (homes)
2023 Total	0.8	0.4	1.3	419
2024 Total	n/a	n/a	n/a	n/a
2025 Total	n/a	n/a	n/a	n/a

Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical Tables for additional detail.

4.3.2 IMPLEMENTATION STRATEGY

4.3.2.1 PROGRAM DELIVERY

New registrations for the New Residential program will close in July 2022. As a result of long lead times for new residential construction, the final year of efficient new residential build completions, enrolled prior to July 2022, will wind up in the first year (2023) of the Settlement Plan.

The New Residential program will be delivered in partnership with contracted Service Organizations, licensed by NRCAN, until wind up is complete in 2023. Customers will continue to work directly with E1 and NRCAN registered EAs for detailed home design advice and program guidance until that time. Upon completion of the new home, a final onsite evaluation is completed by the EAs, and the home is modelled (as built). The modelled results provide an energy rating for the completed new home.

4.3.3 PERFORMANCE INDICATORS

Performance indicators for the New Residential program are provided in Table 35, below.

Table 35: 2023-2025 New Residential Performance Indicators

Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (homes) ^c	Lifetime Unit Cost (\$/kWh) ^d
					incl. carbon	excl. carbon	incl. carbon	excl. carbon		
2023	0.8	0.4	13	1.3	2.6	2.4	4.8	4.4	419	0.06
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
Total	0.8	0.4	13	1.3	2.6	2.4	4.8	4.4	419	0.06

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of households completing upgrades through New Home Construction.

^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

4.3.4 PROGRAM ALTERNATIVES

New Residential investment and savings in the Settlement Plan are included in year 2023 only. The estimates are based on a wind up of the program with new registrations ending in July 2022. The number of completions in 2023 are assumed to be the same in both the Settlement Plan and Alternate Scenario since both are based on the number of expected registrations in 2022. Therefore, there is no variance in the New Residential program between the Settlement Plan and Alternate Scenario – as summarized in Table 36, below.

Table 36: 2023-2025 New Residential Performance Indicators – Comparison of Settlement Plan and Alternate Scenario

Scenario	Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (homes) ^c	Lifetime Unit Cost (\$/kWh) ^d
						incl. Carbon	excl. Carbon	incl. Carbon	excl. Carbon		
Settlement	2023	0.8	0.4	13	1.3	2.6	2.4	4.8	4.4	419	0.06
	2024	-	-	-	-	-	-	-	-	-	-
	2025	-	-	-	-	-	-	-	-	-	-
	Total	0.8	0.4	13	1.3	2.6	2.4	4.8	4.4	419	0.06
Alternate	2023	0.8	0.4	13	1.3	2.6	2.4	4.8	4.4	419	0.06
	2024	-	-	-	-	-	-	-	-	-	-
	2025	-	-	-	-	-	-	-	-	-	-
	Total	0.8	0.4	13	1.3	2.6	2.4	4.8	4.4	419	0.06
Variance from Settlement	2023	0%	0%	(0%)	0%	0%	(0%)	0%	(0%)	0%	0%
	2024	-	-	-	-	-	-	-	-	-	-
	2025	-	-	-	-	-	-	-	-	-	-
	Total	0%	0%	(0%)	0%	0%	0%	0%	0%	0%	0%

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of households completing upgrades through New Home Construction.

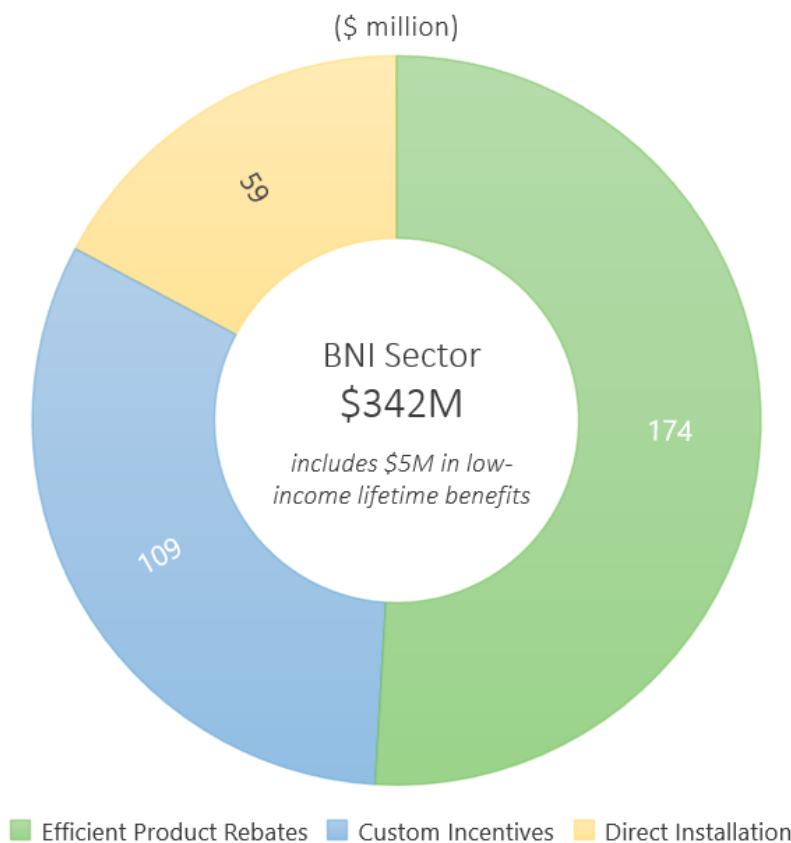
^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

5. BUSINESS, NON-PROFIT & INSTITUTIONAL PROGRAMS & SERVICES

For over a decade, E1 has been a leader in designing and implementing business, non-profit, and institutional (BNI) energy efficiency programs. E1 has built an extremely successful mid-stream delivery pathway, developed a prominent small business turn-key and open market service, and most recently introduced Industrial Energy Managers (IEMs). The Settlement Plan builds on previous achievements with a focus on expanding equity, streamlining delivery approaches, and increasing awareness of the availability and value of energy efficiency.

Increasing participation by BNI customers in energy efficiency programs is an important element of E1's Settlement Plan. During a time when businesses are facing an uncertain economic outlook, energy savings opportunities are diminishing in easy to reach areas, and business priorities may not include investing in energy efficiency. E1 remains focused on the fundamentals of program success – awareness, simplicity, proven value, continuous improvement to the portfolio of services, expanding industry capacity and expertise. Figure 15 outlines the BNI Sector Lifetime Benefits over the 2023-2025 DSM plan period.

Figure 15: BNI Sector Lifetime Benefits



The Settlement Plan aims to help more business customers overcome barriers to participation by making it easier for them to participate in programs, connecting them with expertise specific to their needs, and building on engagement and development efforts. The Settlement Plan supports the adoption of a variety of energy-efficient products and services in areas such as capital retrofit projects, process-focused energy management and new building construction. The Settlement Plan demonstrates an increased shift towards helping customers achieve savings that are more challenging and builds on related steps taken in 2019 that have eliminated incentives for some lighting measures. Enhancements for this plan period, described in the next section, focus on the following key areas:

- decreasing reliance on energy savings from lighting;
- increasing accessibility to programs; and
- increasing the types of benefits delivered by DSM (i.e. including system-peak demand reduction).

The Settlement Plan offers three BNI sector programs comprised of four program components, as presented in Table 37, below.

Table 37: Settlement Plan – BNI Sector Offerings

Program	Program Component	Target Market Segment	Delivery Approach	Enhancements in Settlement Plan	Section Reference
BNI Efficient Product Rebates	Business Energy Rebates	Existing and new construction BNI facilities	Point of sale rebates and mail in rebates	• Mid-stream Commercial Kitchen Rebates	Section 5.1.2.1
Custom Incentives	Custom	Existing and new construction BNI facilities	Facilitated* and financial incentives	• Pay-for-Performance	Section 5.2.2.1
	Strategic Energy Management & Energy Management Information Systems	Industrial, institutional	Facilitated* and financial incentives	• Continued support	Section 5.2.2.2
Direct Installation	Small Business Energy Solutions	Small businesses	Facilitated* and financial incentives	• Commercial Direct Install Stream	Section 5.3.2.1

*Facilitated is defined as providing customers with assistance in identifying energy efficiency opportunities and guidance on implementation to satisfy program requirements.

5.1 EFFICIENT PRODUCT REBATES PROGRAM

5.1.1 OBJECTIVES

Objectives of the BNI Efficient Product Rebates program include:

- encourage businesses to use efficient products in a variety of facilities;
- increase the market penetration of the supported technologies;
- promote the adoption of high-efficiency equipment; and
- transform the market by raising the efficiency of standard practices.

Table 38, below, provides a summary of the participant, industry, environmental, and strategic DSM Portfolio benefits of the Efficient Product Rebates program as designed in the Settlement Plan.

Table 38: Summary of Benefits – Efficient Product Rebates (BNI)

Participant Benefits	Industry Benefits	Environmental Benefits	Strategic DSM Portfolio Benefits
• utility bill savings and improved building comfort • reduced maintenance and extended equipment life • improved access and reduced financial barriers to adoption of energy efficient products • improved visibility, improved customer experience in retail outlets • savings can contribute to corporate environmental goals	• increased sales of energy efficient products • support for a wide range of products including agricultural, horticultural, refrigeration, HVAC, and lighting • local economic development opportunities for distributors and contractors	• reduced GHG emissions due to reductions in energy consumption • reduced waste of inefficient baseline products with shorter useful lives, in particular incandescent and fluorescent lamps • alignment with Provincial and Federal incentives for reduced GHG emissions • increased business and commercial awareness of opportunities to reduce their carbon footprint	• establishes market channels that enable no-effort customer participation • supports codes and standards through incentivizing equipment above baseline standards, driving increased demand for the highest-efficiency products • improves communication channels with industry and customers through a mix of Business Development Manager, Efficiency Preferred Partner network, Onsite Energy Manager, Industrial Energy Manager, and other supports

5.1.2 OVERVIEW

The Efficient Product Rebates program provides BNI customers with financial incentives, in the form of prescriptive/semi-prescriptive rebates or financing, for the installation of energy efficient and system-peak

demand-reducing equipment. The program focuses primarily on equipment that has applicability across a variety of commercial, industrial, and institutional customers and equipment that has predictable energy and system-peak demand savings. The program consists of one program component, Business Energy Rebates, which offers customers two participation pathways, each of which is further described in the section that follows.

5.1.2.1 BUSINESS ENERGY REBATES PROGRAM COMPONENT

The Business Energy Rebates program component offers two participation pathways – Instant Rebates and Mail-In rebates:

- Instant Rebates: customers have access to prescriptive rebates on a limited suite of energy efficiency equipment through point-of-purchase discounts across a province-wide network of distribution partners; and
- Mail-In Rebates: customers have access to prescriptive rebates on a larger suite of energy efficiency equipment through mail-in applications. Through the mail-in pathway, customers can have their rebate adjusted in some cases to reflect the energy savings resulting from the specific conditions of the facility.

The term ‘prescriptive rebate’ refers to a particular rebate value that is calculated prior to a participant purchasing or submitting a proposal for an eligible measure. If a given measure or technology demonstrates energy savings potential, a corresponding rebate value is applied to the purchase of said measure or technology.

Table 39 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Business Energy Rebates program component in the Settlement Plan.

Table 39: Three-Year Summary of the Business Energy Rebates Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
2023 Total	7.4	35.3	6.7	207,143
<i>Low-income</i>	<i>0.09</i>	<i>0.47</i>	<i>0.12</i>	<i>2,738</i>
2024 Total	7.4	35.3	6.7	206,157

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
<i>Low-income</i>	<i>0.09</i>	<i>0.47</i>	<i>0.12</i>	<i>2,725</i>
2025 Total	8.4	38.5	7.2	224,127
<i>Low-income</i>	<i>0.10</i>	<i>0.51</i>	<i>0.13</i>	<i>2,963</i>
Target Market	The target market includes all existing and new construction Nova Scotia business, non-profit and institutional facilities, including multi-unit residential buildings.			
Market Barriers	• <u>Upfront costs</u>: the higher priced energy efficient equipment is a barrier for many customers. • <u>Project return</u>: competing priorities for capital investments. • <u>Lack of knowledge & technical expertise</u>: many customers are not familiar with high efficiency options. • <u>Time & internal capacity constraints</u>: some businesses may not have the internal capacity to consider energy efficiency options (e.g. identify, evaluate) in purchasing decisions.			
Key Components	• Accessible rebates to participants through two options • Product-level expertise and insight into energy efficiency products for end-users • Project management support through energy efficient upgrades			
Measures Promoted	Measures listed under the BNI Efficient Product Rebates program are prescriptive and semi-prescriptive. As the program develops and expands in scope, the list of eligible measures may change, as required. Eligible mail-in measures include: • agriculture • compressed air • heating • IT & datacenters • kitchen • laundry • lighting • refrigeration • solar thermal • pool equipment • pumping • variable frequency drive • water heating Eligible instant rebate measures include: • select lighting measures • refrigeration • pumping			

Program Component History	• 2010 – launched as a part of DSM portfolio, initially modelled closely after successful prescriptive programs offered in other markets, specifically Efficiency Vermont. • 2010 to 2019 – program component success led to an increase in the adoption of LED products in existing buildings and new construction projects throughout Nova Scotia. Along with E1 incentives, decreasing prices and widespread availability have removed some of the barriers for businesses to be able to access and incorporate some of these LED products. • 2019 – removed several lighting categories from the component in response to market transformation and adjusted available rebates on others to help drive the market towards other energy efficient products. • 2020 – launched new system peak demand measures, electric thermal storage, and topped up rebates for the locational DSM pilot in Kentville, referred to as the Klondike Pilot. Introduced a Rooftop Unit (RTU) Fan Speed Control pilot to help retrofit existing buildings to have demand control ventilation via occupancy sensors or CO₂ sensors.
Enhancements in 2023-2025	Offering commercial kitchen incentives in-store via participating retail partners in addition to the commercial kitchen category currently offered through the BNI Efficient Product Rebates Mail-In path. This enhancement refreshes rebates to improve existing incentive offerings, expansion of rebate offerings, and migration to midstream rebates. In 2021, Efficient Product Rebates introduced a horticultural lighting rebate that will continued to be offered in the 2023-2025 DSM Settlement Plan. The introduction of this category will help businesses reduce costs, increase productivity, yield, and quality.

Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical Tables for additional detail.

5.1.3 IMPLEMENTATION STRATEGY

5.1.3.1 PROGRAM DELIVERY

BNI Efficient Product Rebates uses a self-directed approach for both the Instant Rebate and Mail-In incentive pathways. Through Instant Rebates, point-of-purchase discounts are available on a limited range of efficient equipment and products. The Mail-In pathway provides access to a larger variety of high efficiency equipment and products eligible for incentives via pre-approval and post-purchase.

Program partners are crucial to the success of the BNI Efficient Product Rebates program. In particular, electrical and pumping distributors and contractors within the province play a key role in promoting instant rebates through the program. These distributors and contractors also aid customers in the form of product expertise, as well as assistance in completing mail-in applications. Electrical distributors and contractors involved with the BNI Efficient Product Rebates program are active participants in the EPP network, which provides marketing support and training to distributors.

5.1.3.2 MARKETING STRATEGY

The marketing strategy will focus on distributor and contractor engagement, direct email marketing to key customer segments, outreach to trade and industry associations, and event attendance and sponsorships. The marketing strategy will be supported by E1's Business Development team, who work directly with businesses in the target market to identify and develop project opportunities, Onsite Energy Managers, and EPP network members. Specific tactics will include:

- business development engagement;
- outreach to relevant industry and trade associations;
- integrated media plans that may include radio, TV, billboards, social media, streaming, search engine marketing, email marketing, and placements in relevant trade publications;
- participation in trade shows and industry events; and
- distributor training and instore promotion.

5.1.3.3 QUALITY ASSURANCE

The BNI Efficient Product Rebates program has an established quality assurance framework that includes random and targeted site visits, documentation review, and customer surveys.

5.1.4 PERFORMANCE INDICATORS

Performance indicators for the BNI Efficient Product Rebate program are provided in Table 40, below.

Table 40: 2023-2025 BNI Efficient Product Rebates Performance Indicators

Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Lifetime Unit Cost (\$/kWh) ^d
					incl. carbon	excl. carbon	incl. carbon	excl. carbon		
2023	7.4	35.3	525	6.7	3.7	2.5	7.5	5.0	207,143	0.01
2024	7.4	35.3	526	6.7	3.8	2.5	7.6	5.1	206,157	0.01
2025	8.4	38.5	572	7.2	3.7	2.6	7.4	5.1	224,127	0.01
Total	23.2	109.1	1,623	20.6	3.7	2.5	7.5	5.1	637,426	0.01

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of individual products rebated through the Mail-In and Instant Rebates pathways of Business Energy Rebates.

^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

5.1.4.1 LOW-INCOME PERFORMANCE INDICATORS

Low-income performance indicators for the BNI Efficient Product Rebate program are provided in Table 41, below.

Table 41: 2023-2025 BNI Efficient Product Rebates Low-Income Performance Indicators

Year	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Participation (products) ^a
2023	0.5	6.9	0.1	2,738
2024	0.5	6.9	0.1	2,725
2025	0.5	7.6	0.1	2,963
Total	1.4	21.5	0.4	8,426

Columns may not add correctly, due to rounding.

^a The number of individual products rebated through Business Energy Rebates.

5.1.5 PROGRAM ALTERNATIVES

The Efficient Product Rebates Program features a modestly lower amount of participation, with marginally lower incentives, in the 2025 Plan year. This is due to an incentive increase applied within the Settlement Plan that is modelled to produce slightly higher energy and demand savings in the last year of the 2023-2025 DSM Plan period. Table 42, below, presents this difference for the BNI Efficient Product Rebates program.

Table 42: Efficient Product Rebates (BNI) Performance Indicators – Comparison of Settlement Plan and Alternate Scenario

Scenario	Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Lifetime Unit Cost (\$/kWh) ^d
						incl. Carbon	excl. Carbon	incl. Carbon	excl. Carbon		
Settlement	2023	7.4	35.3	525	6.7	3.7	2.5	7.5	5.0	207,143	0.01
	2024	7.4	35.3	526	6.7	3.8	2.5	7.6	5.1	206,157	0.01
	2025	8.4	38.5	572	7.2	3.7	2.6	7.4	5.1	224,127	0.01
	Total	23.2	109.1	1,623	20.6	3.7	2.5	7.5	5.1	637,426	0.01
Alternate	2023	7.3	34.6	515	6.5	3.7	2.5	7.5	5.0	202,966	0.01
	2024	7.3	34.6	515	6.5	3.7	2.5	7.6	5.1	201,999	0.01
	2025	7.5	35.6	531	6.7	3.7	2.6	7.7	5.3	207,791	0.01
	Total	22.1	104.8	1,560	19.8	3.7	2.5	7.6	5.1	612,756	0.01
Variance from Settlement	2023	(2%)	(2%)	(2%)	(2%)	(0%)	(0%)	(0%)	(0%)	(2%)	0%
	2024	(2%)	(2%)	(2%)	(2%)	(0%)	(0%)	(0%)	(0%)	(2%)	0%
	2025	(10%)	(7%)	(7%)	(7%)	(1%)	(1%)	3%	3%	(7%)	(3%)
	Total	(5%)	(4%)	(4%)	(4%)	(0%)	(0%)	1%	1%	(4%)	(1%)

1 Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may
 2 not add correctly, due to rounding.
 3 Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP
 4 using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.
 5 Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.
 6 ^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.
 7 ^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.
 8 ^c The number of individual products rebated through the Mail-In and Instant Rebates elements of Business Energy Rebates
 9 ^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

12 5.2 CUSTOM INCENTIVES PROGRAM

13 5.2.1 OBJECTIVES

14 Objectives of the Custom Incentives program include:

- 15 • influence electrical energy efficiency and system-peak demand reduction projects within Nova
 16 Scotia;
- 17 • build awareness around cost-effective energy efficiency options and the benefits of energy
 18 efficiency to program participants, developers, and builders;
- 19 • reduce barriers to implementing complex, custom energy efficiency projects;
- 20 • increase developer and builder awareness of cost-effective options for improving the energy
 21 efficiency of new buildings;
- 22 • increase the number of new buildings adopting high efficiency design techniques;
- 23 • provide customers with the knowledge and tools required to enable energy management;
- 24 • promote long term relationships with customers to achieve energy sustainability, and cost
 25 reduction objectives; and
- 26 • further diversify the program offerings of E1 by developing new programs from technologies and
 27 methods successfully trialed in the Custom Incentives program.

28
 29 Table 43, below, provides a summary of the participant, industry, environmental, and strategic DSM
 30 Portfolio benefits of the Custom Incentives program as designed in the Settlement Plan.

1 Table 43: Summary of Benefits – Custom Incentives

Participant Benefits	Industry Benefits	Environmental Benefits	Strategic DSM Portfolio Benefits
• utility bill savings and improved building comfort • reduced maintenance and extended equipment life • access to energy expertise through funded studies and on-site energy manager support • improved control over buildings and industrial processes	• support for vendors, installers, and consultants across many industries • advancement in building design, systems, and technology • increased market demand towards more energy efficient buildings and technologies • sharing of energy management strategies between program participants • drives competitiveness in building and maintaining more efficient industrial facilities	• reduced GHG emissions due to reductions in energy consumption • other environmental or non-energy benefits (depending on the project), such as enhanced building value, lease rates, performance, etc. • alignment with Provincial and Federal incentives for reduced GHG emissions • increased commercial and industrial awareness of opportunities to reduce their carbon footprint	• market transformation through promoting and funding buildings that exceed minimum building code • builds relationships with major electricity customers • longer-term relationships between E1 and customers allow sharing of information and experiences with new technologies and energy management approaches • provides a mechanism for incentive support for innovative and complex projects, in a flexible manner that can be customized by vertical and customer need • improves communication channels with industry and customers through a mix of Business Development Manager, Efficiency Preferred Partner network, Onsite Energy Manager, Industrial Energy Manager, and other supports

3 5.2.2 OVERVIEW

4 The Custom Incentives program provides financial incentives and technical assistance to help non-profit,
5 institutional, commercial, and industrial customers reduce their electrical energy consumption and system-
6 peak demand. Support is customized based upon consideration of project-specific energy and system-peak
7 demand savings. The program is designed to accommodate a wide range of customer project types and
8 works directly with customers to identify and implement energy efficiency and system-peak demand
9 reduction projects that are not supported by other E1 programs.

11 The Custom Incentives program is comprised of the following two program components:

- Custom;

- Strategic Energy Management (SEM) & Energy Management Information Systems (EMIS).

Each of these program components is further described in the sections that follow.

5.2.2.1 CUSTOM PROGRAM COMPONENT

Custom offers three services: Retrofit (including compressed air leak audits), New Construction (NC), and Building Optimization (BOpt). To provide more focused support, the Custom group is divided in two parts, one that focuses on Commercial & Institutional (C&I) participants and the other on Industrial participants as shown in Table 44, below.

Table 44: Criteria for Industrial and Commercial/Institutional Offerings in the Custom Program Component

Customer Base	Criteria
Industrial	• Rate code 21, 22, 23 or 25 except municipal, transportation, and Department of National Defence (DND) facilities • Agriculture facilities • Aquaculture facilities
Commercial & Institutional	All other commercial customers, and all: • Municipal facilities • Transportation facilities • DND facilities

Custom has criteria to determine what types of facilities, projects, measures, and costs are eligible. These criteria ensure the program works the way it is intended and that E1 only pays incentives for actions that generate incremental energy savings. This program component enhancement may also provide the opportunity for E1 to integrate its EE and DR programming for cost efficiencies and ease of participation.

Table 45 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Custom program component in the Settlement Plan.

Table 45: Three-Year Summary of the Custom Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (projects)
2023 Total	7.3	22.3	4.7	257

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (projects)
2024 Total	7.5	23.1	4.8	266
2025 Total	7.7	24.2	4.8	278
Target Market	Open to eligible existing and new construction Nova Scotia business, non-profit, institutional, and industrial customers. Despite its broad customer eligibility criteria, the program component typically targets larger energy users.			
Market Barriers	• <u>Upfront costs & internal competition for capital</u>: financial constraints resulting from internal competition for capital; upfront cost requirements for feasibility studies and audits, before energy savings potential is known, can be challenging for companies to justify. • <u>Payback periods</u>: companies often require short paybacks on investments making it challenging for custom energy efficiency projects to compete against other capital investments. • <u>Time & internal capacity constraints</u>: some companies may not have the internal capacity to consider energy efficiency options (e.g. identify, evaluate) in purchasing decisions. • <u>Lack of internal commitment & technical expertise</u>: in-house staff may be unfamiliar with, or face challenges with internal commitment to, new efficient technologies or processes.			
Key Components	• <u>Retrofit</u>: help to conduct scoping and feasibility studies; and assist with the implementation of energy efficiency projects using a customized and flexible approach. • <u>NC</u>: help achieve electrical energy savings in new buildings and for major renovations in existing buildings; and participation begins at the preliminary design stage to ensure the effective implementation of energy efficiency measures and achieve maximum savings. • <u>BOpt</u>: helps organizations conduct an investigation study with the objective of improving building operation efficiency; and assist with the implementation of no-cost or low-cost energy efficiency measures identified through a recommissioning process i.e. operating schedule changes.			
Measures Promoted	A variety of technical and financial assistance is available through the program, which is designed to consider projects individually. This approach allows support to be customized based on case specific energy and system-peak demand savings. Some key areas of support provided through the program include: • financial incentives for initial scoping and feasibility studies to evaluate energy and system-peak demand savings opportunities • financial incentives for energy modelling of new building designs to identify and evaluate energy efficiency upgrades • financial incentives (rebates and financing) for implementing cost-effective electrical energy efficiency and system-peak demand reduction projects • financial and/or technical assistance for improvements to compressed air systems • financial and/or technical assistance to optimize building performance			

Measures Promoted	• financial and technical support for customers to assess and implement energy management opportunities, specifically in the areas of operations, maintenance, and behavioural savings
Program Component History	• 2008 – launched as a single component, custom retrofit as a part of DSM portfolio • 2010 – E1 began administering the program and added a new construction service to help streamline offerings for large BNI participants • 2013 – initiated a compressed air optimization offering • 2014 – introduced a BOpt service, formerly known as existing building commissioning, • 2016 – re-vamped the BOpt service to encourage higher participation with a revised structure and delivery process • 2018 – launched a new construction commissioning pilot to encourage participants to fully commission their building at the end of the construction process • 2020 – divided custom retrofit service into subsector for commercial & institutional and industrial with IEM added; also adjusted eligibility criteria and incentive structure for new construction service to better align with upcoming code changes, including higher levels of efficiency
Enhancements in 2023-2025	Expansion on pay-for-performance pilot efforts offering incentives, typically \$/kWh, which are determined based on the level of savings a customer achieves within a certain timeframe. The level of savings is assessed using a whole building(s) approach that relies on billing or electricity consumption data, as opposed to detailed measurement and verification (M&V) for each efficiency measure installed. This will streamline the M&V processes and be more cost effective. The successful Implementation of a pay-for-performance initiative requires access to AMI data, at scale, to validate performance targets. The introduction of a pay-for-performance structure in the 2023-2025 Plan period, aligns with advances in energy-use feedback programming, the availability of AMI in Nova Scotia and advances in analytical software and products available to access near real-time customer data.

Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical Tables for additional detail.

5.2.2.2 STRATEGIC ENERGY MANAGEMENT & ENERGY MANAGEMENT INFORMATION SYSTEMS PROGRAM COMPONENT

Strategic Energy Management (SEM) offers qualifying industrial organizations a comprehensive approach to energy management. Participants work with a service provider to identify energy saving opportunities and execute an action plan using a 12-month, staged approach. Participants save energy by making changes to operations, maintenance, and behaviours.

SEM is also a conduit for participants to engage E1 in capital upgrades and other E1 services using a single-entry point, while ensuring activities are sequenced, logical, and coordinated. SEM includes a system of

accountability to propel action – participants check-in weekly with the service provider to report on their projects' status. Through SEM, participants integrate energy management into their core businesses, permeating every aspect of their organizations, including operations, processes, and culture. This program component enhancement may also provide the opportunity for E1 to integrate its EE and DR programming for cost efficiencies and ease of participation.

Energy Management Information Systems (EMIS) offers qualifying industrial organizations financial incentives to implement technical systems to better manage their energy use. Participants work with consultants to undergo an audit to define the scope, costs, and savings associated with the system; develop a plan to implement the system; and install and integrate the system into their facilities.

Facilities that engage in the program benefit from a customized, holistic approach to managing their energy. The systems can encompass an entire facility or specific processes or departments within a facility. EMIS includes meters for energy measurement, infrastructure for data collection and storage, software for converting data to information, and support to systematically convert information into action. This program component enhancement may also provide the opportunity for E1 to integrate its EE and DR programming for cost efficiencies and ease of participation.

Table 46 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the SEM & EMIS program component in the Settlement Plan.

Table 46: Three-Year Summary of the SEM & EMIS Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (participants)
2023 Total	0.9	2.7	0.3	8
2024 Total	0.9	2.7	0.3	8
2025 Total	0.9	2.7	0.3	8
Target Market	SEM is available to industrial customers across the province. The program targets larger energy users, such as medium-to-large industrials, and has support for commercial/institutional customers through pilots. EMIS is available to industrial customers across the province. The program targets larger energy users, such as medium-to-large industrials.			

Market Barriers	• <u>Upfront costs & internal competition for capital</u>: financial constraints resulting from internal competition for capital; upfront cost requirements for feasibility studies and audits, before energy savings potential is known, can be challenging for companies to justify. • <u>Payback periods</u>: companies often require short paybacks on investments making it challenging for custom energy efficiency projects to compete against other capital investments. • <u>Time & internal capacity constraints</u>: some companies may not have the internal capacity to consider energy efficiency options (e.g. identify, evaluate) in purchasing decisions. • <u>Lack of internal commitment & technical expertise</u>: in-house staff may be unfamiliar with, or face challenges with internal commitment to, new efficient technologies or processes.
Key Components	• Assisting large and mid-sized industrial companies develop and implement energy management information systems and in implementing strategic energy management • Providing industry with specific tools and a structured path to enable energy management that is information-driven, ongoing, organizational, and systematic • Influencing industry's understanding and management of energy use within Nova Scotia • Support capital energy efficiency projects identified through EMIS and/or SEM • Provide the energy efficiency industry with a structured path to enable strategic energy management
Measures Promoted	A variety of technical and financial assistance is available through the program, which is designed to consider projects individually. This approach allows support to be customized based on case specific energy and system-peak demand savings. Some key areas of support provided through the program include: • financial incentives for initial scoping and EMIS audits to evaluate energy and system-peak demand savings opportunities • financial incentives for EMIS implementation plans, equipment costs, and implementation costs Technical and financial assistance is available through the program, which is designed to support customers with strategic energy management. Some key areas of support provided through the program include: • financial incentives for SEM service provider facilitation • expertise to evaluate energy and system-peak demand savings opportunities
Program Component History	• 2012 – launched EMIS as a pilot • 2013 – introduction of EMIS as a standalone program component • 2014 – launched SEM as a cohort delivery approach • 2016 – integrated the program component into the Custom Incentives program • 2019 – highest number of participants with some participants crossing over from the Strategic Energy Management program component • Present – implemented continuous, individualized uptake approach to better accommodate individual customer timelines.

- 1
- 2 Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical
- 3 Tables for additional detail.

5.2.3 IMPLEMENTATION STRATEGY

5.2.3.1 PROGRAM DELIVERY

The Custom Incentives program structure is designed to overcome customer barriers associated with large upfront costs, lack of in-house capacity and business case requirements. The program is delivered through a combination of E1 staff, contracted partners, and third parties to identify, define, assess, and implement energy saving opportunities. Involved external resources are often consulting engineering firms, efficiency contractors, and service providers, and heating, ventilation, and air conditioning automation companies. The Custom Incentive program components and services have similarities in how they are delivered; however, their processes, incentives, eligibility criteria, and target markets vary to best meet the market's needs while ensuring the program achieves its goals.

The Retrofit service offers participants incentives to offset the cost of scoping studies, feasibility studies, and project implementation.

- Scoping studies can identify opportunities to save electrical energy.
- Feasibility study incentives offer participants financial incentives towards the cost of detailed energy audit to analyze electrical energy-saving measures
- Implementation incentives are initiated once the participant notifies program staff of project completion, submit completed M&V materials, and submit a copy of invoices.

The NC service provides technical advice and energy modelling support in the conceptual and design stages of a project, when businesses can consider implementing the most energy efficient measures at the lowest possible cost. Implementation incentives are provided to help bring down incremental costs associated with constructing a building that is more efficient than one that only meets the building code minimum requirements.

The BOpt service encourages businesses to review their existing building's systems, processes, and operating conditions to ensure they are optimized for the building's current operational needs. Unlike Retrofit projects, BOpt projects are intended to focus on low capital cost operational improvements. BOpt aims to maximize value for participants by using an investigation study to identify opportunities with low implementation costs and short simple payback periods.

EMIS participants hire consultants to perform scoping audits, develop implementation plans, and implement energy management information systems in their facilities. E1 maintains an EMIS Consultant

and Service Provider Roster with a list of firms that meet the program component's requirements. Throughout each stage, E1 works with participants and consultants to ensure the participant is benefiting as much as possible from the program, with realized and maximized energy savings, and a positive customer experience, and to ensure that industry standards and program protocols are upheld.

SEM is delivered through a service provider that works closely with participants to assess their energy use, develop an energy management plan, conduct ongoing modelling of the impacts of energy saving activities, and provide overall support throughout their involvement in the program component. Upon discovering the component, participants sign a Memorandum of Understanding (MOU), attend a kick-off meeting, support data collection activities and energy modelling requirements, establish an energy team and an energy management scope and policy, host annual energy improvement events, and implement various energy saving measures and processes.

5.2.3.2 MARKETING STRATEGY

Promotion of the Custom Incentives program is largely driven by E1's Business Development team. Business Development Managers directly engage clients across 18 market verticals to build long-term relationships and identify and develop project opportunities. This work is supported by an integrated marketing plan and engagement with contractors and consultants, including recruiting key professionals such as architects to join the EPP network. Specific tactics will include:

- business development engagement;
- presentations to relevant industry associations;
- integrated media plans, including search engine marketing, email marketing, placements in relevant trade publications and sponsorships;
- attendance and sponsorship of trade shows and other industry events;
- engagement with developers, architects, mechanical and electrical designers, and others; and
- service provider and contractor training.

5.2.3.3 QUALITY ASSURANCE

The Custom Incentives program has an established framework for quality assurance. Quality control of projects includes pre and post measurement of energy consumption (e.g. direct, modelled, expert review), random and targeted site visits, documentation review and customer surveys.

5.2.4 PERFORMANCE INDICATORS

Performance indicators for the Custom Incentives program are provided in Table 47, below.

Table 47: 2023-2025 Custom Incentives Performance Indicators

Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (projects) ^c	Participation (participants) ^d	Lifetime Unit Cost (\$/kWh) ^e
					incl. carbon	excl. carbon	incl. carbon	excl. carbon			
2023	8.2	24.9	305	5.0	2.5	1.7	4.2	2.8	257	8	0.03
2024	8.4	25.7	313	5.1	2.5	1.7	4.4	2.9	266	8	0.03
2025	8.6	26.8	322	5.1	2.5	1.7	4.4	3.0	278	8	0.03
Total	25.2	77.5	940	15.2	2.5	1.7	4.3	2.9	801	23	0.03

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021. Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs are lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of projects supported through the Custom program component (includes Custom Retrofit, BNI New Construction, and Building Optimization).

^d The number of companies participating in EMIS and SEM.

^e Lifetime unit cost is the quotient of lifetime energy savings and investment.

5.2.4.1 LOW-INCOME PERFORMANCE INDICATORS

Low-income performance indicators for the Custom Incentives program were calculated using 2020 actuals, consistent with the approach used for other programs. In 2020, the Custom Incentives program component had no low-income participation; therefore, low-income participation in the 2023-2025 Plan period was assumed to be zero.

5.2.5 PROGRAM ALTERNATIVES

In the Alternate Scenario, the Custom Incentives program has a marginally lower amount of participation and incentive spending when compared with the Settlement Plan. In addition, Custom Incentives features a lower level of the pay-for-performance enhancement reflecting a decreased emphasis on this aspect of the Custom Incentives program within the Alternate Scenario. Table 48, below, presents this difference for the Custom Incentives program.

Table 48: Custom Incentives Performance Indicators – Comparison of Settlement Plan and Alternate Scenario

Scenario	Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (projects) ^c	Participation (participants) ^d	Lifetime Unit Cost (\$/kWh) ^e
						incl. Carbon	excl. Carbon	incl. Carbon	excl. Carbon			
Settlement	2023	8.2	24.9	305	5.0	2.5	1.7	4.2	2.8	257	8	0.03
	2024	8.4	25.7	313	5.1	2.5	1.7	4.4	2.9	266	8	0.03
	2025	8.6	26.8	322	5.1	2.5	1.7	4.4	3.0	278	8	0.03
	Total	25.2	77.5	940	15.2	2.5	1.7	4.3	2.9	801	23	0.03
Alternate	2023	8.5	25.6	307	5.0	2.5	1.7	4.1	2.8	257	10	0.03
	2024	8.7	26.6	316	5.1	2.5	1.7	4.2	2.9	266	10	0.03
	2025	9.0	27.9	325	5.1	2.5	1.7	4.2	2.9	278	11	0.03
	Total	26.2	80.0	948	15.2	2.5	1.7	4.2	2.8	801	31	0.03
Variance from Settlement	2023	3%	3%	1%	0%	(1%)	(1%)	(2%)	(2%)	0%	28%	2%
	2024	4%	3%	1%	0%	(1%)	(1%)	(3%)	(3%)	0%	37%	3%
	2025	5%	4%	1%	0%	(1%)	(1%)	(4%)	(4%)	0%	47%	4%
	Total	4%	3%	1%	0%	(1%)	(1%)	(3%)	(3%)	0%	37%	3%

2 Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may
3 not add correctly, due to rounding.

4 Annual avoided costs of energy and capacity and annual avoided CO₂e were provided by NS Power, from the 2020 IRP using the
5 Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

6 Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

7 ^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

8 ^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

9 ^c The number of projects supported through the Custom program component (includes Custom Retrofit, BNI New Construction,
10 and Building Optimization).

11 ^d The number of companies participating in EMIS and SEM.

12 ^e Lifetime unit cost is the quotient of lifetime energy savings and investment.

15 5.3 DIRECT INSTALLATION PROGRAM

16 5.3.1 OBJECTIVES

17 Objectives of the Direct Installation program include assisting small businesses to:

- 18 • identify energy savings opportunities within their business;
- 19 • make informed decisions about energy upgrades;
- 20 • overcome financial barriers to completing energy upgrades by offering incentives; and
- 21 • become more profitable and more comfortable through energy efficiency.

22
23 Table 49, below, provides a summary of the participant, industry, environmental, and strategic DSM
24 Portfolio benefits of the Direct Installation program as designed in the Settlement Plan.

Table 49: Summary of Benefits – Direct Installation

Participant Benefits	Industry Benefits	Environmental Benefits	Strategic DSM Portfolio Benefits
• utility bill savings and improved building comfort reduced maintenance costs • reduced maintenance and extended equipment life • improved access and reduced financial barriers to adoption of energy efficient products • improved visibility, improved customer experience in retail outlets • savings can contribute to corporate environmental goals	• increased sales of efficient products • support for a wide range of products including agricultural, horticultural, refrigeration, HVAC, and lighting • local economic development opportunities for distributors and contractors	• reduced GHG emissions due to reductions in energy consumption • reduced waste of inefficient baseline products with shorter useful lives, in particular incandescent and fluorescent lamps • alignment with Provincial and Federal incentives for reduced GHG emissions • increased business awareness of opportunities to reduce their carbon footprint	• access to hard-to-reach customers with limited capital • improves communication channels with industry and customers through a mix of Business Development Manager, Efficiency Preferred Partner network, and Audit pathway supports • increased public awareness of energy efficiency opportunities, driving participation in other E1 programs and services • establishes market channels that ease the expansion of future customer offers

5.3.2 OVERVIEW

The Direct Installation program provides small business customers access to technical assistance and financial incentives for the installation of energy efficient and system-peak demand reduction equipment. The program consists of one program component, Small Business Energy Solutions, which offers customers two participation pathways, each of which is further described in the section that follows.

5.3.2.1 SMALL BUSINESS ENERGY SOLUTIONS PROGRAM COMPONENT

The Small Business Energy Solutions program component provides small business customers access to technical assistance and financial incentives for the installation of energy efficient and system-peak demand reduction equipment. There are two pathways available for customers: self-directed and facilitated. These pathways are described as follows:

- Self-directed: this pathway allows customers who have already identified and selected those energy efficiency opportunities they plan to pursue to select a contractor of their choosing to complete the upgrades, or E1 can direct them to seek out contractors using the EPP network.

- Facilitated: this pathway provides customers with assistance in identifying energy efficiency opportunities with an energy audit performed by a Small Business Energy Auditor. The customer then selects the opportunities they plan to pursue and select a contractor themselves or by using the EPP network.

Financial assistance is provided for a variety of prescriptive energy efficiency products; however, customized incentives are an option for customers when energy savings are identified and estimated by a Small Business Energy Auditor.

Table 50 provides a summary of the three-year investment, energy savings, demand savings, target market, and key components of the Small Business Energy Solutions program component in the Settlement Plan.

Table 50: Three-Year Summary of the Small Business Energy Solutions Program Component

Annual Plan	Investment (\$M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (products)
2023 Total	6.4	11.9	2.5	106,189
<i>Low-income</i>	<i>0.11</i>	<i>0.48</i>	<i>0.14</i>	<i>4,272</i>
2024 Total	6.6	12.2	2.5	110,270
<i>Low-income</i>	<i>0.11</i>	<i>0.49</i>	<i>0.14</i>	<i>4,436</i>
2025 Total	6.8	12.6	2.6	114,333
<i>Low-income</i>	<i>0.11</i>	<i>0.51</i>	<i>0.15</i>	<i>4,600</i>
Target Market	The target market is primarily small commercial businesses, and can also include not-for-profits, multi-unit residential buildings and small industrials. The program is targeted to those small businesses with annual electrical energy consumption of 350,000 kWh or less.			
Market Barriers	<u>Affordability</u>: the cost of equipment/upgrades and lack of access to affordable capital can be a barrier to program participation. <u>Awareness</u>: some potential participants may not understand the costs, benefits, and appropriateness of various projects for their business. <u>Resources</u>: some participants may not have the resources, such as time, human capital for project management, and capacity to hire contractors to implement upgrades.			
Key Components	- Increase customer awareness of cost-effective energy efficiency and system-peak demand reduction options - Help small business make smart energy upgrades - Help small business be more profitable and more comfortable - Remove/eliminate barriers for the adoption of energy efficient and system-peak demand reduction products by Nova Scotia's small businesses			

Measures Promoted	Financial and technical support to small business customers through both a self-directed and facilitated pathway. This support includes: • no-cost energy audits to assess upgrade opportunities • customized measure incentives through the energy audit path • prescriptive rebates through the self-serve path for energy efficient upgrades in the areas of lighting and heating, ventilation and air conditioning primarily and system-peak demand reduction upgrades, specifically through ETS units
Program Component History	• 2008 – launched the Direct Installation in Dartmouth and Pictou County with incentives available for energy efficient lighting upgrades • 2009 – incorporated a recycling component into the program • 2010 – expanded the program to include small businesses province-wide and the broadened the program offering to include non-lighting measures • 2015 – significant changes were made to the program in an effort to increase industry participation. E1 modified the program from a delivery agent model (responsible for all aspects of program delivery including marketing, administration, ordering, delivery, and installation) to a program design that allowed participants to select their own contractors and install approved energy efficiency products. This change coincided with the development of the EPP network, where participants could find qualified contractors for their projects. No-cost energy audits were made available for certain qualifying small businesses where a Small Business Energy Auditor would perform a complete energy audit and develop a list of energy efficiency opportunities for the participant. • 2020 – launched dedicated support through a Small Business Development Manager with an increased focus on growing awareness and participation in the energy audit path where the participant receives additional support from the Small Business Energy Auditor
Enhancements in 2023-2025	Offering of a Commercial Direct Install stream within the Direct Installation program component. This allows Small Business Energy Solutions to offer new and existing measures with less reliance on lighting and less effort involved for the customer. New measures eligible for direct installation include controls for cooler/refrigeration, HVAC, lighting and motors, weatherization/insulation, and custom measures.

Please refer to Attachment 4 – 2023-2025 Settlement Plan Measure-level Energy Efficiency Technical Tables for additional detail.

5.3.3 IMPLEMENTATION STRATEGY

5.3.3.1 PROGRAM DELIVERY

The Direct Installation program is designed to overcome barriers faced by Nova Scotia small businesses, including lack of capital for implementing energy efficient upgrades, lack of time and expertise to identify and assess efficiency opportunities.

The Direct Installation program offers two pathways for small businesses: a self-directed approach (DIY) and a facilitated approach (Energy Audit). The self-directed pathway is designed for those businesses that already know what energy options they wish to pursue. The facilitated pathway is delivered in partnership with contracted Small Business Energy Auditors. Small Business Energy Auditors provide technical support to small business customers. They conduct an energy audit of the business to identify energy upgrade opportunities, provide recommendations to the customer and help them understand the options that have been assessed. Financial incentives are provided for both the cost of the energy audit as well as the implementation of energy efficiency upgrades.

5.3.3.2 MARKETING STRATEGY

The marketing strategy includes a mix of traditional and digital marketing methods, with a focus on direct email marketing, to effectively reach small businesses. Media plans are complemented by business development engagement, engagement with relevant industry associations, and event attendance and sponsorship. Specific tactics will include:

- business development engagement;
- engagement with relevant industry associations (e.g. Chambers of Commerce, Canadian Federation of Independent Business, Restaurants Canada, Black Business Initiative);
- integrated media plans, including radio, TV, billboards, search engine marketing, email marketing, placements in relevant trade publications, and sponsorships;
- attendance and sponsorship of trade shows and other industry events; and
- service provider and contractor training.

5.3.3.3 QUALITY ASSURANCE

Direct Installation has an established quality assurance framework, which includes random and targeted site inspections, documentation review, and customer surveys.

5.3.4 PERFORMANCE INDICATORS

Performance indicators for the Direct Installation program are provided in Table 51, below.

Table 51: 2023-2025 Direct Installation Performance Indicators

Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Lifetime Unit Cost (\$/kWh) ^d
					incl. carbon	excl. carbon	incl. carbon	excl. carbon		
2023	6.4	11.9	172	2.5	2.2	1.5	2.9	2.0	106,189	0.04
2024	6.6	12.2	178	2.5	2.2	1.5	3.0	2.0	110,270	0.04
2025	6.8	12.6	183	2.6	2.2	1.6	3.0	2.1	114,333	0.04
Total	19.8	36.7	533	7.6	2.2	1.5	3.0	2.0	330,792	0.04

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of energy and capacity and annual avoided CO₂e were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

^c The number of individual products rebated through Small Business Energy Solutions.

^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

5.3.4.1 LOW-INCOME PERFORMANCE INDICATORS

Low-income performance indicators for the Direct Installation program are provided in Table 52, below.

Table 52: 2023-2025 Direct Installation Low-Income Performance Indicators

Year	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Participation (products) ^a
2023	0.5	6.9	0.1	4,272
2024	0.5	7.1	0.1	4,436
2025	0.5	7.4	0.1	4,600
Total	1.5	21.4	0.4	13,307

Columns may not add correctly, due to rounding.

^a The number of individual products rebated through Small Business Energy Solutions.

5.3.5 PROGRAM ALTERNATIVES

The Direct Installation program does not vary between the Alternate Scenario and Settlement Plan – as summarized in Table 53, below.

1 Table 53: Direct Installation Performance Indicators – Comparison of Settlement Plan and Alternate Scenario

Scenario	Year	Investment (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC) ^a		Program Administrator Cost Test (PAC) ^b		Participation (products) ^c	Lifetime Unit Cost (\$/kWh) ^d
						incl. Carbon	excl. Carbon	incl. Carbon	excl. Carbon		
Settlement	2023	6.4	11.9	172	2.5	2.2	1.5	2.9	2.0	106,189	0.04
	2024	6.6	12.2	178	2.5	2.2	1.5	3.0	2.0	110,270	0.04
	2025	6.8	12.6	183	2.6	2.2	1.6	3.0	2.1	114,333	0.04
	Total	19.8	36.7	533	7.6	2.2	1.5	3.0	2.0	330,792	0.04
Alternate	2023	6.8	12.5	182	2.6	2.2	1.5	2.9	1.9	111,976	0.04
	2024	7.0	12.9	187	2.7	2.3	1.5	3.0	2.0	116,279	0.04
	2025	7.2	13.3	193	2.8	2.3	1.6	3.0	2.1	120,564	0.04
	Total	21.1	38.7	562	8.0	2.2	1.5	2.9	2.0	348,819	0.04
Variance from Settlement	2023	6%	5%	5%	5%	1%	1%	(1%)	(1%)	5%	1%
	2024	6%	5%	5%	5%	1%	1%	(1%)	(1%)	5%	1%
	2025	6%	5%	5%	5%	1%	1%	(1%)	(1%)	5%	1%
	Total	6%	5%	5%	5%	1%	1%	(1%)	(1%)	5%	1%

2 Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may
3 not add correctly, due to rounding.

4 Annual avoided costs of energy and capacity and annual avoided CO₂e were provided by NS Power, from the 2020 IRP using the
5 Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

6 Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

7 ^a TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs.

8 ^b PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs.

9 ^c The number of individual products rebated through Small Business Energy Solutions.

10 ^d Lifetime unit cost is the quotient of lifetime energy savings and investment.

6. DEMAND RESPONSE PROGRAM & PATHWAYS

E1 is proposing the introduction of a new DR program in the Settlement Plan. This is a significant new development for E1 and the Nova Scotia electricity sector.

DR is defined by the Federal Energy Regulatory Commission (FERC) as, “*changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*”³³

The 2020 IRP selected DR as a new cost-effective resource for the provincial electricity grid because of the on-demand capacity and grid services it can provide. As a flexible resource, DR can support Nova Scotia meeting its climate objectives of retiring coal by 2030, increasing renewables to 80% by 2030, and achieving net zero by 2050³⁴.

E1’s 2019 Potential Study modelled DR potential that was used in the 2020 IRP. It found three cost-effective sub-programs (pathways): direct load control, critical peak pricing (CPP), and BNI curtailment. Since that time, pilots for all three of these pathways have been initiated in Nova Scotia. CPP is being piloted through NS Power’s approved Time-Varying Pricing (TVP) application³⁵, while direct load control and BNI curtailment are being piloted through the E1/NS Power DR Working Group collaboration.

E1 engaged the expertise of Guidehouse (formerly Navigant Consulting) in the development of its DR Plan including DR modelling and a DR Roadmap. The 2023-2025 DR modelling builds on the work conducted for the 2019 Potential Study, which was also completed by Guidehouse. The DR Roadmap provides additional implementation details and considers how DR can ramp over the period 2021-2030. The DR Roadmap has been included as Attachment 5 – Demand Response Roadmap.

E1’s DSM Plan proposes expanding the direct load control and BNI curtailment pathways. It also supports NS Power’s CPP rate through enabling technologies (i.e. providing smart thermostats to CPP participants).

³³ Reports on Demand Response and Advanced Metering. (2022) <https://www.ferc.gov/industries-data/electric/power-sales-and-markets/demand-response/reports-demand-response-and>

³⁴ Environmental Goals and Climate Change Reduction Act, SNS 2021, c.20

³⁵ M09777, Nova Scotia Power, Time-Varying Pricing Tariff Application, November 30, 2020, and NSUARB Order, June 22, 2021.

In addition to the three pathways identified in the 2019 Potential Study, three new pathways are included in E1's DR Plan: behavioural DR, electric vehicle charging, and behind-the-meter battery. Incorporating these additional pathways will allow E1 and NS Power to test additional DR technologies, delivery approaches, and use cases in Nova Scotia. It will provide customers with additional choices and reach a broader range of customers. Over time, a more diverse DR portfolio may also help E1 and NS Power achieve the capacity requirements from DR identified in the IRP.

Since 2019, E1 and NS Power have worked collaboratively to develop, launch, and assess DR pilots to ascertain their feasibility and scalability. The pilots provide valuable learning on use cases (benefits), costs, unit impacts, participant interest/satisfaction, as well as operational details including how NS Power's system operator will use the resources, and E1 and NS Power's roles.

Throughout the remainder of 2022, and the 2023-2025 DSM Plan period, it will be important that E1 and NS Power continue to collaborate closely and remain open to adjusting plans based on the latest learnings and insights from the pilots and other sources to ensure programs are providing the best possible value to ratepayers. The DR program proposed in this plan is innovative and could establish Nova Scotia as a leader in DR activities in Canada. This is in part because:

- E1 and NS Power's collaborative approach to DR delivery is innovative in industry; and
- DR is relatively new in Canada, with most jurisdictions currently in the piloting stage. The majority of established DR programs in the United States are based on summer-peaking utilities, meaning there is less industry experience with winter peaking utilities.

The DR proposed in the Settlement Plan could be best viewed as an ambitious testing period for E1 and NS Power to further define how DR will be operationalized in Nova Scotia, to determine the optimal mix of DR delivery pathways, optimize costs, and learn more about possible use cases and their benefits. E1's proposed DR program, as developed by Guidehouse, is comprised of two program components – covering both the Residential and BNI sectors, which are further described in Attachment 5 – Demand Response Roadmap.

6.1 OBJECTIVES

Objectives of the DR program include:

- achieve demand response capacity that is available to NS Power to utilize during peak periods;

- provide customers with the knowledge and tools required to enable demand management;
- diversify E1's program offerings by supporting control and storage technologies; and provide customers with new opportunities to save money; and
- learn more about how best to effectively deliver DR programs in Nova Scotia.

6.2 BENEFITS

Table 54, below, provides a summary of the participant, industry, environmental, and strategic DSM Portfolio benefits of the DR Program as designed in the Settlement Plan.

Table 54: Summary of Benefits – Demand Response

Participant Benefits	Industry Benefits	Environmental Benefits	Strategic DSM Portfolio Benefits
• financial incentives for shifting or curtailing load • access to new controls and information to better manage energy and demand • better understanding of demand opportunities	• equips industry actors with more comprehensive solutions (i.e. energy efficiency and capacity-focused initiatives) • creates demand for products and services to support project implementation, such as equipment installations • supports the adoption of emerging technologies (e.g. batteries, electric vehicles) in the Nova Scotia market	• integrates with energy efficiency to jointly manage all aspects of electricity consumption and usage • opportunity for improved renewable generation following and reduced reliance on carbon intensive peaking plants • may support electrification through reduced financial barriers to adoption and mitigation of electrification peak load impacts	• creates on demand flexible capacity and grid services • may facilitate beneficial electrification and customer connections to the system by addressing capacity constraints • improves cross-utility coordination of capacity-focused programming, which may facilitate more flexible load creating efficiencies and cost-savings for ratepayers

The primary utility use case for current DR pilots (i.e. the residential direct load control water heating and BNI curtailment pilots) is load leveling (i.e. peak demand reduction). The benefits of this use case can be characterized as the established avoided costs of generation, transmission, and distribution, which were used in DR Plan modelling. The modelling results for the DR program currently indicate that the costs to deliver these programs outweigh the benefits. The benefits are quantified using the current avoided cost calculations.

An objective of current and future pilots will be to explore additional use cases, and if possible, quantify the benefits of these use cases. Future use cases that have been identified through the E1/NS Power DR Working Group include:

- intermittent renewable generation following (load shifting);
- generation contingency (10-minute operating reserve);
- distribution congestion management;
- cold load pickup relief; and
- fast frequency response.

6.3 OVERVIEW

Within Guidehouse's DR Roadmap, there are two program components: Residential DR and BNI DR. Each of the Residential and BNI program components offer multiple pathways to provide a fulsome portfolio of ratepayer options to receive economic incentives and support in return for enrollment and participation. These pathways, developed by Guidehouse, are further described in the sections that follow.

6.3.1 RESIDENTIAL DEMAND RESPONSE PROGRAM COMPONENT

The Residential DR program component aims to help facilitate a more flexible residential load that may provide residential customers with economic incentives and/or more visibility and control of their loads.

In the Settlement Plan, E1 will explore the implementation of up to five pathways for residential customers: battery control, behavioural DR, direct load control, enabling technologies through CPP rates, and electric vehicle managed charging. These pathways, along with a summary of the three-year investment, new installed demand capacity, total available demand capacity, and target market, are described in Table 55, below, and in Attachment 5 – Demand Response Roadmap.

Table 55: Three-Year Summary of the Residential Demand Response Program Component

Annual Plan	Investment (\$M)	New DR Capacity (MW)	Available DR Capacity (MW)	Participation ³⁶ (participants)
2023 Total	0.4	0.1	0.2	374

³⁶ total active participants in each year – i.e. participants enrolled in any given year are counted each year that participation occurs

Annual Plan	Investment (\$M)	New DR Capacity (MW)	Available DR Capacity (MW)	Participation ³⁷ (participants)
<i>Low-income</i>	<i>0.04</i>	<i>0.01</i>	<i>0.02</i>	<i>31</i>
2024 Total	2.2	2.8	2.9	14,468
<i>Low-income</i>	<i>0.16</i>	<i>0.24</i>	<i>0.26</i>	<i>1,742</i>
2025 Total	2.8	4.2	7.1	39,096
<i>Low-income</i>	<i>0.25</i>	<i>0.40</i>	<i>0.66</i>	<i>4,858</i>
Target Market	The target market is primarily residential customers, and can also include renters, diverse and underserved communities, landlords responsible for utility bills, and residential customers on dynamic (time-varying) rate structures.			
Market Barriers	• <u>Awareness</u>: some potential participants may not understand the costs, benefits, and appropriateness of various projects for their residence. • <u>Resources</u>: some participants may not have the resources, such as time, human capital for project management, and capacity to hire contractors to implement upgrades. • <u>Hassle factor</u>: demand response can require customers to make choices that inconvenience them temporarily. This may include reduced comfort, reduced productivity, and products/services being unavailable during DR events.			
Program Component Pathways	• Battery Control – utility control of behind-the-meter batteries for load shifting and dispatching to the grid. Customers receive an upfront enrollment incentive as well as an annual payment to participate in DR events. • Behavioural DR – targeted notifications and messaging are provided to customers to encourage peak shaving, e.g. alerts, targeted notifications, tips, and personalized communications • Direct Load Control – utility control of end-use equipment including smart thermostats (mini-split heat pumps, central heat pumps, and electric baseboards), and electric water heaters. E1 has included both a bring-your-own-device option (with Instant Savings incentives available) and a direct install option. Customers receive an annual payment to participate in DR events. • Enabling Technologies (CPP) – customers on a Critical Peak Pricing (Dynamic Pricing) rate are eligible to receive enabling technologies, such as a smart thermostat. Having enabling technologies increases the average load impact per customer. • Electric Vehicle Managed Charging – managed charging of electric vehicles (EV) either through EV supply equipment (EVSE) or on-board charging control.			
Supported Technologies	• behind-the-meter batteries • smart thermostats for electric resistance baseboard, mini-split heat pump systems, and central heat pumps • domestic hot water controllers and connected water heaters • electric vehicle supply equipment and on-board charging controllers			

³⁷ total active participants in each year – i.e. participants enrolled in any given year are counted each year that participation occurs

Please refer to Attachment 6 – 2023-2025 Demand Response Technical Tables for additional detail.

6.3.2 BNI DEMAND RESPONSE PROGRAM COMPONENT

The BNI DR program component aims to help facilitate more flexible non-residential load that may provide customers with economic incentives and/or more visibility and control of their loads.

In the Settlement Plan, E1 will explore the implementation of up to four pathways available for BNI customers: battery control, curtailment, direct load control, and enabling technologies through CPP rates. These pathways, along with a summary of the three-year investment, new installed demand capacity, total available demand capacity, and target market, are described in Table 56, below, and in Attachment 5 – Demand Response Roadmap.

Table 56: Three-Year Summary of the BNI Demand Response Program Component

Annual Plan	Investment (\$M)	New DR Capacity (MW)	Available DR Capacity (MW)	Participation ³⁸ (participants)
2023 Total	1.1	2.8	2.8	32
2024 Total	1.3	4.3	7.1	606
2025 Total	2.1	3.6	10.7	1,055
Target Market	The target market is comprised of all non-residential customers, and can also include diverse and underserved communities, landlords responsible for utility bills, and customers on dynamic (time-varying) rate structures.			
Market Barriers	<u>Awareness</u>: some potential participants may not understand the costs, benefits, and appropriateness of various projects for their business. <u>Resources</u>: some participants may not have the resources, such as time, human capital for project management, and capacity to hire contractors to implement upgrades. <u>Hassle factor</u>: demand response can require customers to make choices that inconvenience them temporarily. This may include reduced comfort, reduced productivity, and products/services being unavailable during DR events.			
Program Component Pathways	- Battery Control – utility control of behind-the-meter batteries for load shifting and dispatching to the grid. Customers receive an enrollment incentive to install batteries as well as an annual payment to participate in DR events. - Curtailment – firm capacity reduction commitment. \$/kW payment based on capacity commitment regardless of whether DR events are called. When DR events are called, participants are paid based on actual kW reduced during the event, plus receive additional energy payment (\$/kWh) based on actual energy reduced during DR events.			

³⁸ total active participants in each year – i.e. participants enrolled in any given year are counted each year that participation occurs

Program Component Pathways	• Direct Load Control – utility control of end-use equipment including smart thermostats (mini-split heat pumps, central heat pumps, and electric baseboards), and electric water heaters. E1 has included both a bring-your-own-device option (with Small Business Energy Solutions/Business Energy Rebates incentives available) and a direct install option through SBES. Customers receive an annual payment to participate in DR events. • Enabling Technologies (CPP) – customers on a Critical Peak Pricing (Dynamic Pricing) rate are eligible to receive enabling technologies, such as a smart thermostat. Having enabling technologies increases the average load impact per customer.
Supported Technologies	• behind-the-meter batteries • smart thermostats for electric resistance baseboard, central heat pump, and mini-split heat pump systems • commercial hot water controllers and connected water heaters • customized control systems for curtailable loads such as: HVAC systems, standard or advanced (networked) lighting controls, water heating systems, or total industrial facility loads

Please refer to Attachment 6 – 2023-2025 Demand Response Technical Tables for additional detail.

6.4 IMPLEMENTATION STRATEGY

6.4.1 PROGRAM DELIVERY

The DR program structure is designed to overcome customer barriers associated with lack of awareness, lack of resources, and the “hassle factor” experienced by customers participating in DR events for customers (e.g. reduced control over their equipment during DR events). The DR program is intended to help residential and BNI customers modify their usage during peak events when there is value to the utility to shift load. The program will be delivered through a combination of E1 staff in collaboration with NS Power, contracted partners, and third parties to identify, define, assess, and implement system-peak load shifting opportunities. E1 will explore a variety of delivery approaches through each of the pathways available through DR program components. It is anticipated that delivery approaches may evolve over the duration of the Settlement Plan as E1, and NS Power, navigate the launch of new DR initiatives. E1 will integrate the DR program, and technologies, with existing EE programs, where appropriate.

6.4.2 MARKETING & OUTREACH STRATEGY

E1 will leverage its experience marketing energy efficiency programs and demand response pilots, and its existing relationships with NS Power and DSM Administrators in other leading jurisdictions to develop an effective marketing and outreach strategy for the DR program. This work may include engaging the expertise of a consultant to assist in strategy development. E1 will work with its creative, digital, and media

agency partners to identify and profile the target market, develop messaging, and establish the appropriate mix of traditional and digital marketing methods. The strategy is expected to also include direct client engagement from E1's Business Development team as well as contractor education and training.

6.4.3 QUALITY ASSURANCE

For DR pathways the framework is expected to leverage applicable EE quality assurance activities for pathways co-delivered with EE activities. The quality assurance framework is also expected to include test events, customer surveys, and in-person and remote inspections.

6.5 PERFORMANCE INDICATORS

DR is a valuable tool for managing peak demand on the electricity system, offering utilities a lower-cost alternative to acquiring additional flexible generation capacity. DR resources, sometimes called virtual power plants, can be and are often called upon to temporarily reduce load during peak times. In contrast, energy efficiency results in permanent electricity consumption reductions through replacement of inefficient products and equipment, or improvements to building envelope through air sealing or insulation.

DR involves the addition of new demand capacity – i.e. recruiting customers, installing enabling technologies, and connecting them to the applicable aggregator or Distributed Energy Resource Management System (DERMS) so the capacity can respond to events or price signals. Capacity must also be maintained annually so that it remains available to the utility. This may require annual aggregator/DERMS costs, annual incentive payments to customers, and on-going customer service/education. Available demand capacity describes how much DR is available to the utility during the winter peak period. It is net of participant opt-outs, attrition, and unavailable capacity.

Demand capacity is measured based on the availability during the winter peak period (i.e. December through February). Depending on the technology, the capacity available at other times may vary considerably. For example, smart thermostats controlling electric resistance heating will have high availability in the winter peak period and will have insignificant, or no, availability in the summer months.

E1 proposes a performance indicator of new demand capacity, and available demand capacity. Both will be measured during the winter peak period (December through February) and claimed in the second calendar

year of the winter peak period. For example, demand response capacity available in December 2022 to February 2023 will be claimed in 2023, after the winter period is completed.

Performance indicators for the DR program are provided in Table 57, below.

Table 57: 2023-2025 Demand Response Performance Indicators

Year	Investment ^a (\$ million)	New DR Capacity (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^b	Program Administrator Cost Test (PAC) ^c	Participation (participants) ^d	10-Year Levelized Unit Cost (\$/kW-year) ^e
2023	1.5	2.9	3.0	-	-	406	-
2024	3.5	7.0	10.0	-	-	15,074	-
2025	5.0	7.8	17.9	-	-	40,151	-
Total	10.0	17.8	17.9	1.1	0.7	40,151	229.59

Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may not add correctly, due to rounding.

Annual avoided costs of capacity were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

Total cost-effectiveness tests are calculated using the sum of each year's present value of benefits and costs

^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

^b TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life.

^c PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to include the expected full program life.

^d total active participants in each year – i.e. participants enrolled in any given year are counted each year that participation occurs

^e Calculated by taking the net present value of costs and MWs for each DR pathway over the 2022-2031 timeframe; includes all E1 and NS Power costs

6.5.1 LOW-INCOME PERFORMANCE INDICATORS

Low-income performance indicators for the DR program are provided in Table 58, below.

Table 58: 2023-2025 Demand Response Low-Income Performance Indicators

Year	New DR Capacity (MW)	Available DR Capacity (MW)	Participation (participants) ^a
2023	0.01	0.02	31
2024	0.24	0.26	1,742
2025	0.40	0.66	4,858
Total	0.7	0.7	4,858

^a The number of low-income residents participating in a Demand Response pathway

Within the DR Plan model, the residential customer class was classified as either residential market or residential low-income. The assumptions used in the model include the prevalence of low-income customers in the general population, and Guidehouse assumptions of the likelihood of a low-income customer participating in DR pathway.

6.6 PROGRAM ALTERNATIVES

E1 engaged Guidehouse in the development of both the Settlement Plan and Alternate Scenario. In order to develop the DR Alternate Scenario, the following adjustments were made:

- EV charging and DR Behavioural pathways were removed because they had the smallest potential, and it was not feasible to keep six delivery pathways in the smaller Alternate Scenario;
- the delivery of direct install smart thermostats was removed from the DR Alternate Scenario because it had been removed from the EE Alternate Scenario and these measures were assumed to be co-delivered;
- Incentives were reduced, where applicable, to reflect the lower required participation; and
- Direct Load Control (minus smart thermostats), Critical Peak Pricing, BNI Curtailment, and BTM Battery were adjusted downwards to achieve an Alternate Scenario of 8.3 MW and \$5.5 million.

Table 59, below presents this difference for the DR program.

1 Table 59: Demand Response Performance Indicators – Comparison of Settlement Plan and Alternate Scenario

Scenario	Year	Investment ^a (\$ million)	New DR Capacity (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^b	Program Administrator Cost Test (PAC) ^c	Participation (participants) ^d	10-Year Levelized Unit Cost (\$/kW-year) ^e
Settlement	2023	1.5	2.9	3.0	-	-	406	-
	2024	3.5	7.0	10.0	-	-	15,074	-
	2025	5.0	7.8	17.9	-	-	40,151	-
	Total	10.0	17.8	17.9	1.1	0.7	40,151	229.59
Alternate	2023	1.3	1.4	1.5	-	-	196	-
	2024	1.8	3.3	4.8	-	-	2,660	-
	2025	2.6	3.5	8.3	-	-	5,605	-
	Total	5.6	8.2	8.3	1.0	0.7	5,605	214.68
Variance from Settlement	2023	(14%)	(50%)	(50%)	-	-	(52%)	-
	2024	(49%)	(53%)	(52%)	-	-	(82%)	-
	2025	(49%)	(55%)	(54%)	-	-	(86%)	-
	Total	(44%)	(54%)	(54%)	(10%)	2%	(86%)	(6%)

2 Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may
3 not add correctly, due to rounding.

4 Annual avoided costs of capacity were provided by NS Power, from the 2020 IRP using the Base level of DSM for Scenario 2.0C.

5 Avoided costs of transmission and distribution were provided by NS Power in 2021.

6 Total cost-effectiveness tests are calculated using the sum of each year's present value of benefits and costs

7 ^a Investment for DR includes only E1's required investment for the Settlement Plan. It is recognized that in order for DR benefits
8 to be realized, NS Power collaboration and investment will also be required. This may include investment for staff resource, event
9 calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

10 ^b TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs
11 and benefits are taken to include the expected full program life.

12 ^c PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to
13 include the expected full program life.

14 ^d total active participants in each year – i.e. participants enrolled in any given year are counted each year that participation
15 occurs

16 ^e Calculated by taking the net present value of costs and MWs for each DR pathway over the 2022-2031 timeframe; includes all
17 E1 and NS Power costs

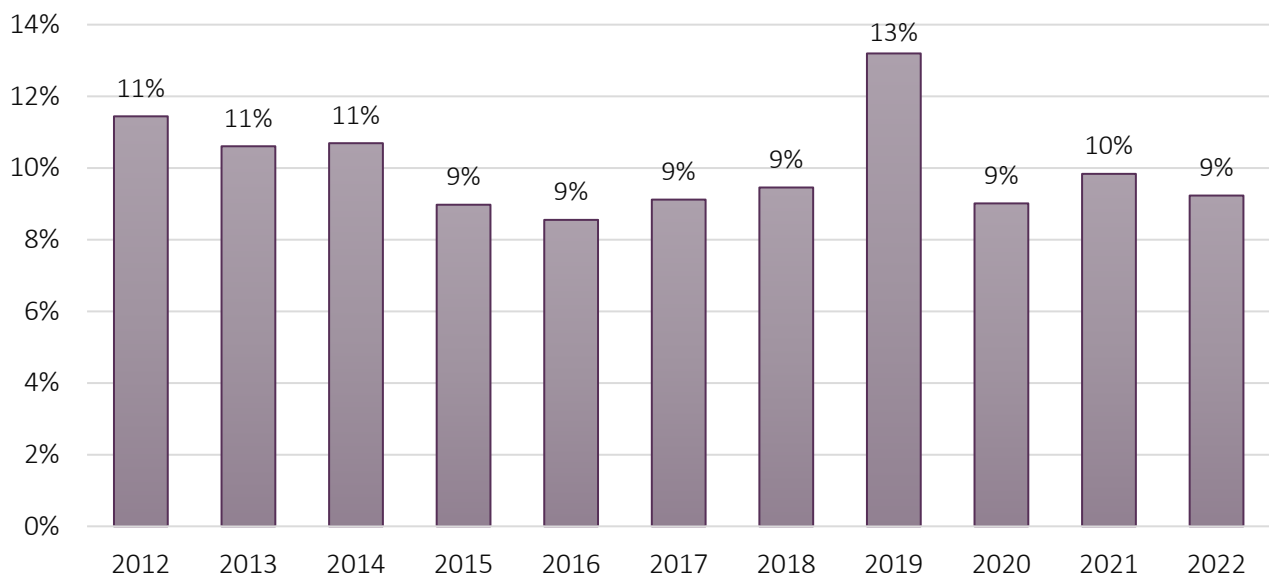
7. ENABLING STRATEGIES

E1 has delivered energy efficiency and conservation programs through annual and/or three-year DSM Plan cycles since 2010. Beginning with the development of its first DSM Plan for the 2012 program year, E1 has included an Enabling Strategies component in its DSM portfolio focused on three categories:

- Education and Outreach;
- Development and Research; and
- Other Enabling Strategies.

Over the past decade, enabling strategies activities have contributed to building capacity in Nova Scotia's energy efficiency industry by increasing awareness about energy efficiency and conservation, supporting market adoption through innovative product and service offerings, and enabling Nova Scotians to make informed energy choices through education and tools. Historically, E1 has invested an average of 10% of its total DSM Portfolio investment in Enabling Strategies³⁹ – as shown in Figure 16, below.

Figure 16: Planned Enabling Strategies Investments as a Percentage of DSM Portfolio (2012 to 2022)



This crucial component of the DSM portfolio has also supported the evolution and maturity of E1. In its early years, E1 heavily focused its activities on Education and Outreach. This has been paramount in driving greater awareness and prominence in the franchise's market presence. In its 2020-2022 DSM Plan, E1

³⁹ Approved DSM Plan investments in Enabling Strategies

began to shift focus to support future programming through innovation, research, and development. In 2020, E1 celebrated one decade since its inception – and the final year of the current Plan (2022), marks one decade of independent DSM planning and administration of energy efficiency and conservation activities in Nova Scotia.

The DSM landscape is rapidly evolving. Topics like electrification and distributed energy resources are gaining prominence, market opportunities continue to mature, and equity is a growing concern as governments, program administrators, and other stakeholders are increasingly focused on reducing GHG emissions, and new technologies are emerging. These and other trends are reflected in the Settlement Plan, including the Enabling Strategies.

7.1 GOALS & OBJECTIVES

The Enabling Strategies component of the Plan serves several purposes: improving product and service offerings through innovation, increasing education and awareness about products and services to increase participation, building industry capacity, supporting the transformation of the Nova Scotia market, and providing Nova Scotians with the tools to make informed decisions about their energy behaviours. Investment in Enabling Strategies also allows E1 to conduct activities that improve its overall impact for Nova Scotians.

The key objectives of the 2023-2025 DSM Enabling Strategies include:

- address non-cost barriers to participating in DSM programs and services – e.g. providing education, offering more virtual options, and making it easier to access energy efficiency expertise and professional services to implement projects;
- evolve DSM programs and services through innovation, product development and pilots, and improvements to delivery of these services; and
- continue to drive market transformation and increased capacity of the energy efficiency industry.

Over the 2023-2025 Plan period, E1's Enabling Strategies will better equip the organization, the industry, and all Nova Scotians to meet the challenges of the rapidly changing energy landscape. This includes shifting climate conditions, market maturity and transformation, emerging technologies, and post-pandemic economic impacts. As E1 developed the Enabling Strategies component of the Settlement Plan, the

approach taken built on its firm historical foundation and looked to several emerging topics crucial to preparing for the future.

E1 identified its key areas of focus, which are:

- heightened focus on innovation, pilots and new technologies, and emerging topics including beneficial electrification and deeper energy savings;
- identify and address participation barriers amongst diverse and underserved communities;
- increased efforts in support of market transformation; and
- renewed emphasis on building capacity to support current and future program implementation.

7.2 EDUCATION & OUTREACH

7.2.1 OBJECTIVES

The objective of Education and Outreach activities is to increase program participation by providing Nova Scotians with information on reducing their energy consumption, communicating participant benefits, and improving access to energy efficiency services. Education and Outreach activities also help, over time, to establish energy efficiency and conservation behaviours as a cultural norm in Nova Scotia. These activities will:

- provide Nova Scotians with access to efficiency expertise and support;
- improve the public's understanding of how to achieve energy and demand savings and influence their decisions to become energy efficient;
- address barriers to implementing upgrades, such as the availability of qualified products and contractors; and
- ensure the energy efficiency industry has the knowledge, skills, and capacity to meet current and future demand for programs and services and support the adoption of emerging technologies.

7.2.2 OVERVIEW

Seven in ten residents and businesses say that it is important for them to reduce their use of energy, while four in ten still feel they need help understanding how to achieve energy savings⁴⁰, highlighting an important opportunity for Enabling Strategies activities in the 2023 to 2025 Plan period. These activities

⁴⁰ Narrative Research, 2021 DSM Report, Prepared for EfficiencyOne, January 2022.

will build on E1's experience and expertise, and take into account recent feedback from Nova Scotians, including non-participants, through formal and informal research.

Table 60 provides a summary of the three-year investment and areas of focus for the Education & Outreach component of Enabling Strategies in the Settlement Plan.

Table 60: Three-Year Summary of the Education & Outreach Component of Enabling Strategies

Annual Plan	Investment (\$M)
2023 Total	1.4
2024 Total	1.5
2025 Total	1.5
Areas of Focus	<u>Community Outreach & Education</u> : activities aimed at increasing public awareness and education through outreach such as community events, home shows, and tradeshow, presentations and information sessions, media interviews and appearances, and educational resources.
	<u>Diverse & Underserved Communities</u> : providing more dedicated and specialized support for diverse and underserved communities through community liaisons and partnership development, youth engagement in energy efficiency careers, diversity, equity and inclusion training and support for the energy efficiency industry, and community-based events, workshops, and information sessions.
	<u>Partnership Development</u> : initiatives such as continued growth and development of Efficiency Preferred Partner network growth and development, strategic partnerships and sponsorships, and workforce development initiatives – e.g. job fairs, recruitment support for contracted Service Providers.
	<u>Green Schools Nova Scotia & Post-Secondary Education</u> : continued support of the Green Schools Nova Scotia program and partnerships with post-secondary institutions, including the NSCC. Enhancements will include new Mi'kmaw Engagement Officer and new opportunities to engage youth in energy efficiency careers, including facilitated internships with Efficiency Preferred Partner network members, and field trips to expose youth to careers in the energy efficiency industry.
	<u>New Residential Market Transformation</u> : efforts in training, education, and supporting industry capacity development for actors in the residential new construction market such as building designers, contractors, builders, and enforcement officials.

7.2.3 ACTIVITIES WITHIN AREAS OF FOCUS

7.2.3.1 COMMUNITY OUTREACH & EDUCATION

Community outreach and education activities promote program awareness and participation by allowing E1 to provide Nova Scotians with information on reducing their energy consumption and the benefits of implementing energy efficiency upgrades. They also allow E1 to gather feedback from residents and

businesses on ways to improve access to its programs and services. Activities within this area of focus include:

- advertising to increase awareness and understanding of how to achieve energy savings and positively influence decisions to participate in DSM programs;
- engaging Nova Scotians on the Efficiency Nova Scotia website, social media channels, emails and newsletters, and media appearances and stories, to promote participation in DSM programs;
- improving access to virtual support by implementing live chat software;
- attending and sponsoring events, presentations, information sessions and demonstrations that promote energy efficiency programs and behaviours, including home shows, trade shows, and community events; and
- developing educational resources, guides, and tools to improve Nova Scotians' understanding of how to achieve energy savings in their home or business.

Performance goals for community outreach and education activities will be developed and may include, awareness levels, website and email conversion rates, social media engagement, and referrals from home shows, trade shows, and community events.

7.2.3.2 DIVERSE & UNDERSERVED COMMUNITIES

Diverse and underserved communities, or groups, such as Mi'kmaw and African Nova Scotians, are communities that experience collective barriers to participating in society based on age, ethnicity, disability, economic status, gender, race, sexual orientation, and other factors. Education and outreach efforts with these communities will include:

- developing culturally appropriate marketing materials, educational resources, guides and tools to improve engagement and understanding;
- employing community liaisons from the respective communities to facilitate communication and coordinate activities between E1 and each community, including giving presentations, hosting and attending meetings, and gathering feedback and ideas to improve energy efficiency programs and delivery approaches;
- developing partnerships with community organizations;
- hosting and sponsoring events to introduce youth from these communities to careers in the energy efficiency industry; and

- hosting and sponsoring diversity, equity, and inclusion training for EPP network members to create employment opportunities for underrepresented groups in the energy efficiency industry.

Performance goals for diverse and underserved communities will be developed and may include referrals from community liaisons and partnerships, youth engaged, and training engagement and participation.

7.2.3.3 PARTNERSHIP DEVELOPMENT

Partnership development activities focus on growing and developing the EPP network to improve access to energy efficiency products and contractors. The EPP network builds relationships with various organizations to reach target markets and advance other Enabling Strategies objectives. Through partnership developments, E1 will support growth in the knowledge, skills, and capacity of the energy efficiency industry to meet current and future demand for programs and services, and to promote the adoption of emerging technologies. Activities within this area of focus include:

- continuing to recruit new members to the EPP network, including businesses owned or operated by members of diverse and underserved communities;
- continuing to implement quality assurance standards and practices to ensure EPP network members provide Nova Scotians with high quality services and products;
- developing strategic partnerships with identified organizations in relevant sectors to reach more Nova Scotians;
- hosting and sponsoring training and other professional development opportunities to upgrade the knowledge and skills of the energy efficiency industry;
- attending job fairs to promote careers in the energy efficiency industry;
- hosting and sponsoring events to introduce youth to careers in the energy efficiency industry; and
- sharing job postings and offering other recruitment support to increase the capacity of contracted Service Providers.

Performance goals for partnership development activities will be developed and may include, new members, quality assurance metrics (e.g. complaints, average time to resolve complaints), referrals from strategic partnerships, training engagement and participation, youth engaged, and referrals from career events and other recruitment activities.

7.2.3.4 GREEN SCHOOLS NOVA SCOTIA & POST-SECONDARY EDUCATION

The Green Schools Nova Scotia initiative has formed part of E1's Enabling Strategies since 2016. The initiative engages over 25,000 students across 340 schools each year to adopt smarter energy habits. E1 has also developed strategic partnerships with the NSCC, Saint Mary's University, and Dalhousie University to promote energy efficiency curriculum in post-secondary education and to attract students to careers in the energy efficiency industry. Activities within this area of focus will include:

- continuing to offer free educational resources, support, activities and workshops to teachers across all schools in Nova Scotia;
- developing culturally appropriate materials, including added resources, promotions and social media content;
- offering community engagements to faith-based and cultural groups to increase participation of youth in diverse and underserved communities;
- continuing to provide field trips that expose youth from across the province to careers in the energy efficiency industry; and
- facilitating co-op placements and/or internships with EPP network members.

Performance goals will be established for education activities and may include, student engagements, field trip engagement and participation, and co-op and internship placement results.

7.2.3.5 NEW RESIDENTIAL MARKET TRANSFORMATION

With the increased popularity in heat pump adoption, E1 has an opportunity to expand influence further into the new construction industry. In an effort to help meet the provincial climate goals of net zero by 2050, broadening and taking a more holistic approach is required to facilitate change in the new construction market. In 2022, E1 will be re-designing a market transformation program and that will be launched in 2023, overlapping the wind up of the New Home Construction program component.

In the 2023-2025 Plan years, E1 will place increased emphasis on activities that help to redefine the market for energy efficiency through market transformation and customer education. Market transformation is a high-level framework of programs to create market change by creating accelerated adoption of energy efficient products, services, and practices. These efforts often support increasing the stringency and compliance of building codes. In 2023-2025, E1 is transitioning from a traditional resource acquisition

approach to a market transformation approach for the new residential market. Activities within this area of focus may include:

- conducting baseline studies and market research to determine current market state, building code and efficiency literacy levels, and best practices established in other jurisdictions;
- providing training, education, and supporting industry capacity development for market actors such as building designers, contractors, builders, and enforcement officials;
- developing case studies, supporting code awareness and enforcement, and promotional activities to build awareness and compliance; and
- leveraging online tools to engage and inform, increase consumer demand for energy efficient buildings, and improve access to market actors engaging in high efficiency construction standards.

Market transformation efforts focused on appliances, equipment, and heat pumps is further described under the Development & Research category, below.

7.3 DEVELOPMENT & RESEARCH

7.3.1 OBJECTIVES

E1 uses an evidence-based approach to design effective programs that support customers. Investments in research and development ensure that E1's programs and services continue to evolve in response to changes in the DSM landscape, market conditions, and as new technologies emerge. These activities will:

- leverage E1's internal subject matter expertise to innovate in preparation for the next decade of DSM;
- conduct market research, studies, and analyses to quantify DSM potential, evaluate emerging technologies, and test new delivery approaches;
- support the evolution of DSM programs and future DSM Resource Plans via research and development initiatives;
- drive market transformation and advancements of energy efficiency codes and standards through studies and research, partnerships with local and federal governments, market actors, and policymakers; and
- improve customer service and engagement through customer relationship management.

7.3.2 OVERVIEW

The Development & Research category historically includes research and development efforts not directly affiliated to specific programs or services. Keeping customers front-and-center when making decisions around program delivery, design, and offerings is an important aspect of delivering cost-effective energy and demand savings. Reducing barriers to enrollment and offering compelling services and delivery approaches is critical. Through investments in development and research, E1 is able to maintain flexibility to adapt to evolving conditions, like those presented by the global COVID-19 pandemic and prepare its DSM portfolio to meet the evolving needs of a changing climate and energy landscape.

Table 61 provides a summary of the three-year investment and areas of focus for the Development & Research component of Enabling Strategies in the Settlement Plan.

Table 61: Three-Year Summary of the Development & Research Component of Enabling Strategies

Annual Plan	Investment (\$M)
2023 Total	1.5
2024 Total	1.5
2025 Total	1.5
Areas of Focus	<u>Innovation & Emerging Technologies</u> : driving participation and uptake through product demonstrations, technical papers, pilots, and new initiatives.
	<u>Market Research</u> : DSM potential studies; research into emerging areas such as deeper energy savings.
	<u>Beneficial Electrification</u> : strategy development and collaboration to inform future beneficial electrification efforts and E1's role in supporting decarbonization in Nova Scotia.
	<u>Locational Efforts</u> : exploration of locational DSM efforts is an area of interest for E1 in the 2023-2025 Plan period.
	<u>Market Transformation</u> : codes and standards support through the Canadian Standards Association; heat pump, appliance, and equipment standards; baselining and market research; code compliance efforts; and savings attribution research.
	<u>Data & Analytics</u> : integrate AMI data into operations; improvements to E1's data environment; analytics to drive participation through targeted communication.

7.3.3 ACTIVITIES WITHIN AREAS OF FOCUS

7.3.3.1 INNOVATION & EMERGING TECHNOLOGIES

In 2023-2025, E1 will increase its focus on innovation, pilots, and emerging technologies within the development and research category of its Enabling Strategies. These activities enable adoption of measures, offerings, or delivery approaches that demonstrate cost-effectiveness and/or energy savings potential but are not yet fully understood or established in the Nova Scotia market. Focusing on product development and pilot projects generates Nova Scotia-specific findings about cost-effectiveness and market demand before making larger investments in program deployment and delivery. Innovation pilots typically facilitate early-stage analysis and testing on emerging technologies, strategies for program delivery, or initiatives that have been implemented elsewhere but not in the Nova Scotia market. Activities within this area of focus include:

- developing programs for current and future DSM Plan portfolios;
- researching and exploring the market potential for emerging technologies and service delivery models;
- redeveloping or improving existing DSM program and product offerings;
- conducting pilots to evaluate new initiatives, program enhancements, measures, or delivery approaches; and
- promoting more favorable market conditions for the increased use of energy-efficient products and services, including strategies to implement demand response activities.

Future areas of focus are expected to include electrification, deep retrofits, virtual audits, and market transformation.

7.3.3.2 MARKET RESEARCH

E1 will continue to undertake market research initiatives to better understand how to meet changing market conditions, reach underserved segments of customers, and best leverage new information and technology. Activities within this area of focus include:

- understanding customers and market conditions through specific research, such as:
 - motivations and barriers;
 - trends and preferences in consumer behaviour (including energy consumption); and
 - other research or studies, as needed.

- researching opportunities from other jurisdictions and partnering with other DSM experts;
- exploring opportunities to help businesses manage and reduce electrical demand;
- conducting research to assess current and future DSM market potential through potential studies and baselining;
- exploring emerging areas of focus, such as net zero (or deeper energy retrofits to obtain near net zero) options for existing residential; and
- contributing to the advancement of innovative demand side management efforts through technical papers, collaboration with other jurisdictions, and studies.

7.3.3.3 BENEFICIAL ELECTRIFICATION

Beneficial electrification is a form of electricity DSM focused on the conversion of existing end use applications from fossil fuel sources to electricity, with the intended result of reducing total GHG emissions. Examples of electrification include heat pumps replacing oil-fired heating systems, electric water heaters replacing oil-fired heaters, and electric vehicles. E1 defines beneficial electrification (BE) as electrification activities having the following attributes:

- environmental benefits – must result in a net reduction in source GHG emissions;
- customer benefits – must save money for the customer over the life of the equipment; and
- grid flexibility – must either not increase annual system-peak demand, or have the flexibility (controls, capacity, etc.) to be removed from utility system-peak through curtailment or shifting.

NS Power's 2020 IRP identified electrification as a key element of its strategy to meet the electricity system's contribution to federal and provincial GHG reduction targets, although no participant or utility costs for electrification were modelled in the IRP. NS Power will be working with stakeholders throughout the recently announced IRP update process, which included more clarification on the electrification strategy. E1 expects to be an active stakeholder in the development of NS Power's electrification strategy and is, as an independent administrator, well-positioned to deliver programs in the future. E1's areas of focus, in supporting electrification, may include:

- participating in the electrification working group identified as part of the NS Power IRP Action Plan⁴¹;
- assisting in the development of an electrification strategy for Nova Scotia, generally; and

⁴¹ https://irp.nspower.ca/files/key-documents/final-irp-report/E3_NS-Power_2020_IRP_Report_final_Nov-27-2020.pdf

- supporting developmental work on the strategy in the following specific areas:
 - determining the mechanisms through which BE activities are funded, planned, approved, and evaluated;
 - establishing E1's role in the ongoing design and administration of BE programs. Specifically, identifying how E1's assets and capabilities, developed through years of investment by electricity ratepayers and taxpayers, should be optimized to support BE objectives;
 - establishing a cost effectiveness testing methodology for BE measures and programs, including the process through which the benefits and avoided costs of BE are quantified; and
 - identifying how BE programs and measures will interact with other DSM programs for the optimum benefit of electricity ratepayers.

7.3.3.4 LOCATIONAL EFFORTS

Locational DSM provides geographically targeted demand-side resources to alleviate capacity-constrained system resources, such as substations and distribution assets. Efforts can include demand response technologies, energy efficiency offers (such as in the Klondike Pilot), or a combination of both. The Klondike Pilot launched in December 2019 is a limited-time locational DSM offering to NS Power customers serviced by the Klondike substation in Kentville. As E1's first geo-targeted effort, the Pilot provided learnings and identified opportunities to build on the delivery approach for future efforts. The Klondike Pilot launched shortly before the global COVID-19 pandemic and was challenged with the cancellation of several in-person events and marketing outreach efforts. Locational DSM is an area of interest for future development that requires full collaborative development with NS Power. E1 intends to build on its pilot development work with NS Power through the E1/NS Power DR Working Group to explore and identify opportunities for locational pilots or efforts, as a demand-side resource for capacity-constrained assets.

7.3.3.5 MARKET TRANSFORMATION

In 2023-2025, E1 will place increased emphasis on activities that help to redefine the market for energy efficiency through market transformation and customer education. Market transformation is a high-level framework of programs that create a market change and may result in savings (e.g. energy, demand, GHG emission reductions) by accelerating adoption of energy efficient products, services, and practices. These efforts often support technologies like appliances and heat pumps but also include increasing the

stringency and compliance of building codes. Of particular focus for E1 is the residential new construction market, which is further described under the Education & Outreach category, above.

Pursuing market transformation aligns with recommendations E1 has received through its Evaluation and Verification activities. As E1 transitions from a traditional resource acquisition approach to a market transformation approach, activities within this area of focus may include:

- conducting baseline studies, market research, and collaborating closely with levels of governments, to improve adoption of, and compliance with, higher codes and standards in the appliances, equipment, and heat pump markets;
- helping Nova Scotians overcome market barriers through coordinated efforts in education, product demonstration, and marketing;
- aligning provincial regulations with the federal level standards will create energy-saving opportunities, i.e. introduction of standards which meet or exceed federal minimums;
- collaborating with other jurisdictions, organizations, and governments in the development and implementation of stringent and harmonized standards, through activities such as training, education, and industry support;
- improving building code compliance and developing specialized supports, resources, and training for building officials;
- piloting market transformation approaches, such as code compliance support, to help establish stakeholder relationships, gather valuable insights on the market behaviour, and inform the design of future initiatives at scale; and
- promoting the optimal use of energy efficient equipment, such as rightsizing heat pumps and proper commissioning.

In 2023-2025, E1 will continue to advocate for and support the adoption of energy-efficiency standards within provincial and federal regulations. E1 will also continue its participation in the Canadian Standards Association's Steering Committee on Performance, Energy Efficiency, and Renewables, and associated Strategic Resource Task Force, as well as other related committee participation as opportunities arise. In addition, E1 will maintain its technical and policy support to the provincial and federal governments relating to electrification, DR, energy storage, and other forms of DSM.

7.3.3.6 DATA & ANALYTICS

Over the past decade of DSM administration, the use of data and analytics has become increasingly important to support the effective delivery of the DSM portfolio by providing insights on pilot and program results, highlighting energy-saving opportunities and areas for process improvements, and informing the strategies and tactics best suited to reach Nova Scotians and drive participation. With the large-scale deployment of AMI in Nova Scotia well underway, access to high-resolution customer data will provide opportunities for program development and delivery. Activities within this area of focus include:

- integrating AMI data to implement enhancements (e.g. Custom Pay-for-Performance) and new developments (e.g. Residential Behaviour/Behavioural DR), as outlined in the Settlement Plan;
- use of advanced analytics (e.g. machine-learning and artificial intelligence) to:
 - develop more customized offerings and information to customers based on electricity usage patterns and load shape; and
 - determine potential for process improvements (e.g. test the effectiveness of touchless energy audits, more reliance on usage data for measurement and verification, where appropriate).
- Improving and developing other customer-centric approaches to engagement and service delivery, such as:
 - testing alternative marketing approaches;
 - piloting new technologies and approaches to make delivery of savings easier for customers, and to improve customer engagement and interactions; and
 - examining and piloting new use cases using customer energy usage data.

7.4 OTHER ENABLING STRATEGIES

7.4.1 OBJECTIVES

Investments in E1's Other Enabling Strategies:

- support the evolution of DSM programs and future DSM Resource Plans via research and development initiatives;
- ensure the cohesive oversight, development, and reporting of DSM Resource Plans and other regulatory filings; and
- improve stakeholder engagement through relationship management, consultations, and involvement in development activities.

7.4.2 OVERVIEW

Other Enabling Strategies for 2023-2025 is comprised of Regulatory Affairs activities, which include the following activities:

- NSUARB processes, such as DSM Plan development and reporting;
- DSM Advisory Group initiatives and stakeholder consultation;
- industry research; and
- legal work related to regulatory initiatives.

Table 62 provides a summary of the three-year investment and areas of focus for the Other Enabling Strategies component of Enabling Strategies in the Settlement Plan.

Table 62: Three-Year Summary of the Other Enabling Strategies Component of Enabling Strategies

Annual Plan	Investment (\$M)
2023 Total	0.9
2024 Total	1.6
2025 Total	1.6
Areas of Focus	<u>DSM Plan Development & Reporting</u> : development of cyclical DSM Resource Plans and portfolios, reporting and accountability for performance targets, and consultative processes relating to DSM Plan developments.
Areas of Focus	<u>Stakeholder Engagement</u> : regular and technical sessions of the DSM Advisory Group, regulatory consultants and stakeholders, and relationships with working groups such as E1/NS Power Demand Response Working Group.
Areas of Focus	<u>Other Regulatory Initiatives</u> : research and development into new and emerging regulatory areas, monitoring of the Nova Scotia and external regulatory environments, and support for all NSUARB processes.

7.4.3 ACTIVITIES WITHIN AREAS OF FOCUS

7.4.3.1 DSM PLAN DEVELOPMENT & REPORTING

DSM Plan development and reporting activities are an essential function of E1's Regulatory Affairs Team. Through its Enabling Strategies, Regulatory Affairs manages all demand side management related filings, including the development of E1's DSM Resource Plans, and progress reporting through quarterly and annual DSM Reports. 2023-2025 activities within this area of focus include:

- developing the 2026-2028 DSM Resource Plan;

- working with NS Power, and other stakeholders, to gain support of the 2026-2028 DSM Resource Plan with NSUARB-approval of same; and
- developing and/or filing regular report updates with the NSUARB on topics, such as:
 - 2023, 2024, 2025 Quarterly Reports;
 - 2023, 2024, 2025 Evaluation Reports;
 - 2022, 2023, 2024 Annual Progress Reports;
 - 2022, 2023, 2024 Audited Financial Statements;
 - 2023-2025 Historical-looking Rate and Bill Impact Analysis filed as part of the 2026-2028 DSM Resource Plan Application; and
- other studies, reports, and updates, as appropriate.

Section 9 provides the details of Reporting activities developed for the Settlement Plan.

7.4.3.2 STAKEHOLDER ENGAGEMENT

Support and engagement of stakeholders is a topic of significance to E1. As described in Section 2.1 of this Plan, stakeholder feedback following the development of the 2020-2022 DSM Plan centered around the desire to be engaged early, often, and meaningfully in the development processes for its DSM Plans. In response, E1 initiated the development of this Plan earlier than ever, and worked to incorporate multiple iterations of stakeholder consultations, feedback opportunities, and reports providing updates along major milestones in the 2023-2025 development process.

E1 will continue to engage stakeholders outside of the development of the DSM Plan throughout 2023-2025 on both regular and emerging topics. Engagement activities are expected to include:

- Regular DSMAG meetings;
- Technical DSMAG Sessions;
- One-on-one stakeholder consultations; and
- Maintaining a DSMAG SharePoint Site as a central source for all DSMAG documents.

7.4.3.3 OTHER REGULATORY INITIATIVES

Other regulatory initiatives include NSUARB processes, not directly tied to DSM Plan development or reporting, such as industry research and jurisdictional scans, and legal work related to regulatory matters.

1 Activities within this area of focus include:

- 2 • engaging and fostering relationships with other jurisdictions to support continuous improvement
- 3 of E1's DSM planning and administration processes;
- 4 • working with the Evaluation and Verification Consultants to facilitate their efforts and pursuing
- 5 commitments arising from the 2023-2025 DSM Resource Plan regulatory process;
- 6 • researching new and emerging topics or regulatory areas for consideration in the DSM planning
- 7 and administration landscape;
- 8 • supporting and/or leading the development of other studies, reports, and updates, as appropriate;
- 9 • monitoring of the Nova Scotia and external regulatory environments for new developments or best
- 10 practices for consideration in E1's regulatory context;
- 11 • supporting E1's participation in all NSUARB processes; the electricity system is embarking on a
- 12 significant period of transformation which will result in more (and more complex) regulatory
- 13 proceedings which are expected to be interwoven with DSM; and
- 14 • informing and supporting other E1 departments on E1 and non-E1 regulatory matters.

8. EVALUATION

E1's measurement and evaluation activities are a crucial component of its Regulatory Affairs functions. Through independent, third-party measurement and evaluation processes, E1 is able to stay accountable to its tracked performance metrics, program results, and DSM portfolio outcomes. These processes are vital to improve the operations of EE and DR programs, measure their impacts, and attribute energy and demand savings to E1's efforts and ratepayer investments. Evaluation activities provide E1 with timely, tailored feedback through annual recommendations. These recommendations provide E1 with essential insights on the opportunities, barriers, and areas for improvement within existing programs, pilots, and new initiatives. Activities within this area of focus include developing and/or filing regular report updates with the NSUARB on topics, including Evaluation Reports and evaluation recommendation updates.

E1 proposes to take a similar approach to evaluation in the Settlement Plan as in 2020-2022 DSM Resource Plan, where evaluation activities are conducted to ensure accurate determination of net electrical energy and net system-peak demand savings. Evaluation activities will be condensed where appropriate, in recognition of the maturity level that some E1 program components have reached. Evaluation activities will include an annual impact evaluation for each program in each of the three years. In all cases, evaluation activities will be undertaken to ensure the accurate determination of net electrical energy and net system-peak demand savings, to maximize the value of the evaluation process, and to provide opportunities for continuous improvement.

8.1 IMPACT EVALUATIONS

Annual impact evaluations will provide E1, stakeholders, and the NSUARB with up-to-date impacts on net electrical energy and net system-peak demand savings as progress indicators towards the overall approved Settlement Plan energy and system-peak demand savings targets. E1 will work with the Evaluator to determine if a program component requires a full impact evaluation or a condensed impact evaluation. A condensed impact evaluation involves using some or all of the previous year's impact evaluation parameters, methodologies and related calculations referenced in previous evaluated results. Condensed impact evaluations are expected to consist of energy (annual and lifetime) and system-peak demand savings results. Distortion effects would include any changes or updates to programs and measures that occurred following the filing of the 2022 evaluation reports. This means that for stable, mature program

components, the Evaluator may use the previous year's unitary savings values, realization rates, and/or installation rates.

A comprehensive impact evaluation (previously referred to in the 2020-2022 DSM Resource Plan as a full impact evaluation) involves reviewing key elements to help establish the baseline definitions, savings calculation methodologies and the values of the parameters used to calculate savings. Comprehensive impact evaluations are expected for newer program components and those with recent changes or more variable savings parameters. The Evaluator will design and conduct a full scope of evaluation activities for program components that require a comprehensive impact evaluation.

The COVID-19 pandemic presented an opportunity to pilot innovative solutions where traditional evaluation activities were restricted, such as virtual site visits. E1 will explore with the Evaluator how to leverage insights from these activities to support the continued use of virtual site visits where appropriate in the future.

8.2 PROCESS AND MARKET EVALUATIONS

Program process and market evaluations will remain consistent with what has occurred in the 2020-2022 DSM Resource Plan. Process evaluations identify and recommend improvements that are likely to increase the program's efficiency or effectiveness, while maintaining high levels of participant satisfaction. Market evaluation studies indicate how the overall supply chain and market for energy efficiency products work, and how they have been affected by the program(s). E1 will work with the Evaluator to determine what program components should be evaluated based on the following criteria:

- newly created program components that have not yet been evaluated;
- program components that have incurred major changes;
- program components that received many recommendations from the evaluator;
- program components that have a variance of energy savings larger than 25 percent of plan year target; and
- program components that have not received a process evaluation in the past two years.

8.3 DEMAND RESPONSE

As a part of the Settlement Plan, DR will be introduced as a new program with several pathways under the Residential and BNI DR program components. DR program evaluation is aimed at verifying and quantifying the available capacity to the utility during the winter peak period.

In the 2021/2022 winter period, E1 developed several pilot initiatives that focused on reducing demand during the Nova Scotia peak period. E1 engaged the Evaluator to provide research support and advice on event-based DR evaluation and reporting. The Evaluator reviewed DR program documentation and guidelines from grid operators, utility regulators, research and standards development organizations, electric utilities, and DR aggregators to understand and document current best practices in event-based DR program evaluation. In the jurisdictions included in the Evaluator's research, DR programs are evaluated using ex-ante and ex-post evaluation strategies depending on whether evaluating highly variable loads or homogeneous loads. E1 plans to use these evaluation strategies to evaluate the DR pilots and will help inform the evaluation methodology for each DR program component for the Settlement Plan. E1 will work with the Evaluator to form a preliminary evaluation plan for each DR program component.

9. REPORTING

E1 proposes to report on the implementation of the Settlement Plan through Quarterly Reports and Annual Progress Reports (APR).

9.1 ANNUAL PROGRESS REPORTS

In the first quarter of each calendar year, E1 will file an APR with the NSUARB, which will include the following information:

- a summary of the context, activities and milestones achieved in the prior year, including the status of the annual performance indicators;
- a management discussion and analysis of any major discrepancies (25 percent or greater variance) relative to the original plan's intent and forecasts;
- a summary of expenditures, energy, and system-peak demand savings for each program; and
- Plan period forecast information (savings and expenditures) for the three-year Plan period⁴².

In the event E1 proposes significant changes to elements within an approved plan, advance notice will be provided to the NSUARB and stakeholders within the APR. Significant changes include:

- adding a new Program;
- terminating an existing Program;
- increasing or decreasing the 3-year plan budget for the total Residential sector and for the total BNI sector by more than 25 percent; and
- increasing or decreasing the 3-year plan savings target for the total Residential sector and for the total BNI sector by more than 25 percent.

9.2 QUARTERLY REPORTS

E1 will file quarterly reports with the NSUARB for quarters one through three of each year⁴³. The reports will provide quarterly status updates and service highlights and communicate course adjustments (e.g. mid-course adjustments) within the current approved DSM Resource Plan.

⁴² M09750, EfficiencyOne Performance Alignment Study, April 21, 2020, at page 4, lines 5-10.

⁴³ E1 will file its quarterly reports in accordance with the NSUARB's Revised Filing Dates letter, issued January 9, 2018, as follows: Q1 – May 25; Q2 – August 25; Q3 – November 25.

E1 proposes to continue reporting quarterly on the following metrics, including:

- quarterly and year-to-date (YTD) highlights (comparison of savings targets, mid-course adjustments, results and discussion of 25 percent or greater variances in energy and demand savings or investment results at the program level);
- YTD investment by rate class (compared to annual planned mid-course adjusted expenditures);
- sector highlights (results, participation, and items of interest by program, as well as low-income results);
- other activities (organized by Enabling Strategies categories); and
- updated year-end forecast information for savings targets and spending.

9.3 MID-COURSE ADJUSTMENTS & FLEXIBILITY

E1 often makes limited adjustments to an approved DSM Resource Plan to reflect changes in market conditions and updated insights from program and organizational evaluations unknown at the time of DSM Resource Plan development. When setting 2023-2025 Mid-Course Adjustments (MCAs), E1 will follow the same approach as was taken for the 2020-2022 DSM Resource Plan MCAs. This approach includes the following:

- E1 will provide explanations of changes, that have a variance in energy savings, demand savings, or investment that are 25 percent or more at a program level.
- As per above, and dependent on approved cost allocation methodology, E1 will undertake reasonable efforts to consider impacts to any customer rate class on an annual basis that result from program changes.
- E1 will provide written advance notice of its intent to implement mid-course adjustments by program and their customer rate class impacts in the APRs for the 2023-2025 DSM Resource Plan period and will file the MCAs with the Quarterly Report in Q1. It is E1's position that it is not able to provide advance notice of mid-course adjustments resulting from third-party evaluation reports, as these adjustments are made after receipt of these reports.

9.4 AUDITED FINANCIAL STATEMENTS

E1 will retain the services of an external financial auditor to prepare audited annual financial statements. These will be filed with the NSUARB in the second quarter of the following year, no later than April 28 in accordance with the NSUARB's Revised Filing Dates letter issued January 9, 2018.

9.5 RATE & BILL IMPACT ANALYSIS

E1 will file its historical Rate and Bill Impact Analysis (RBIA) and forward-looking RBIA as part of each DSM Resource Plan. The historical RBIA estimates the high-level, long-term impact to rates and bills of all DSM activities up to and including those of the previous calendar year, as well as any future DSM investments that have been approved by the NSUARB. The forward-looking RBIA estimates the high-level, long-term impact to rates and bills of all DSM activities conducted as part of the proposed DSM Resource Plan.

9.6 DEMAND SIDE MANAGEMENT ADVISORY GROUP

The DSMAG is a forum to provide strategic or directional advice and stakeholder perspectives on current or emerging DSM issues including development of future DSM applications and plans. Throughout the 2023-2025 Plan period, E1 will continue to facilitate DSMAG meetings in pursuit of the objectives agreed to in DSMAG's Revised Terms of Reference⁴⁴.

9.7 PERFORMANCE METRICS

For the 2023-2025 Plan period, E1 proposes the following definitions and requirements for Performance Targets and Thresholds as consistent with requirements outlined in the Standardized Filing Framework⁴⁵.

9.7.1 DEFINITIONS

To provide clarity, the following definitions are used:

- **Performance Metric:** A quantifiable measure that is used to track and assess the status of a specific achievement.
- **Performance Indicators:** A set of particular performance metrics used to indicate or monitor progress toward performance targets. Performance Indicators are management tools that provide information to allow an organization to take action to help it deliver on performance targets.

⁴⁴ E1 was directed by the NSUARB in matter M09096 (2020-2022 DSM Plan) to revise the existing Terms of Reference (TOR) of the DSMAG. E1 undertook a full review of the existing TOR in consultation with DSMAG members. On June 30, 2020, DSMAG Revised Terms of Reference were filed with the NSUARB. The revised TOR requires an annual review; this was completed in 2021 in consultation with DSMAG members and a revised TOR was filed with the NSUARB on September 20, 2021.

⁴⁵ In accordance with the Consensus Agreement to the 2016-2018 DSM Resource Plan, Parties agreed to establish a Standardized Filing Framework for future applications to approve a DSM Supply Agreement. The Standardized Filing Framework was approved by the NSUARB September 13, 2016 (M07543).

- **Performance Target:** A performance metric expressed as a specific quantified goal that identifies the desired outcome of an activity at a specific point in time. In this Application Performance Targets refer to NSUARB-approved targets.
- **Performance Threshold:** A predefined quantity, percentage, or range which identifies the allowable deviation from a Performance Target within which the actual outcome is considered to have achieved success. In this Application, Performance Thresholds refer to NSUARB-approved thresholds.

9.7.2 PERFORMANCE TARGETS & THRESHOLDS

- Performance Targets⁴⁶ apply to the period of the NSUARB-approved Supply Agreement with NS Power, rather than annually; and
- E1 is deemed to be in substantial compliance with the NSUARB-approved Plan Performance Targets if 90 percent or greater achievement is reached on each of the cumulative annual energy savings and cumulative annual system-peak demand savings Performance Targets⁴⁷. If less than 90 percent is achieved of either cumulative annual energy savings or cumulative annual system-peak demand savings Performance Targets, E1 understands that the NSUARB would use its discretion to determine appropriate action.

Performance Targets consist of:

- Cumulative annual energy savings; and
- Cumulative annual system-peak demand savings.

Performance Indicators consist of:

- Annual incremental energy savings (reported by program and rate class);
- Cumulative annual energy savings (reported by program and rate class);
- Annual lifetime energy savings (reported by program and rate class);
- Annual incremental system-peak demand savings (reported by program and rate class);
- Cumulative annual system-peak demand savings (reported by program and rate class);

⁴⁶ Performance targets are at the portfolio (i.e. DSM Plan) level.

⁴⁷ The cumulative annual system-peak demand savings Performance Target does not include Demand Response savings from new demand capacity or available demand capacity.

-
- 1 • Annual new demand response capacity and available demand response capacity (reported by
 - 2 program);
 - 3 • Cumulative new demand response capacity and available demand response capacity (reported by
 - 4 program) ⁴⁸;
 - 5 • Total ratepayer benefits;
 - 6 • Total spending (reported by program and rate class);
 - 7 • Customer satisfaction; and
 - 8 • Reporting on low-income program participation, expenditures, and savings through a variety of
 - 9 methods, including estimation based on geographic census information.

⁴⁸ For the DR program, E1 proposes a performance indicator of new demand capacity and available demand capacity. Both will be measured during the winter peak period (December through February) and claimed in the second calendar year of the winter peak period. For example, demand response capacity available in December 2022 to February 2023 will be claimed in 2023 after the winter peak period is completed.

10. CONCLUSION

The Settlement Plan is responsive to the climate emergency and helps advance recent environmental goals preparing for the future. The Settlement Plan positions E1 to achieve levels of DSM in the future and is a transition from where we are today and where we need to be if we are to accomplish net zero by 2050. As a result, savings targets are 1.2% of NS Power's load, an increase from 1.0% today, and will save over 1,700 kilotonnes of lifetime greenhouse gas emissions.

The Settlement Plan is expanding accessibility and equity to all Nova Scotians through the reintroduction of an Affordable Single-family Homes and Residential Behaviour program components, increased support to Nova Scotia small businesses who have been heavily impacted by COVID-19, greater support for Mi'kmaw communities through a Diverse and Underserved Communities initiative, and increased Education and Outreach activities.

The Settlement Plan is cost effective and affordable. It delivers \$543M in lifetime benefits to ratepayers, a return three times greater than the investment of \$173M with a payback in under five years, while providing average participant bill savings between 1.2% and 7.9%.

The Settlement Plan is achievable, reflects stakeholder feedback and subject matter expertise, and is in the best interest of ratepayers. The Settlement Plan represents growth, both for energy efficiency and demand response resources.

Appendix A

Attachment 1: Rate Class Payback Graphs

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LIST OF FIGURES

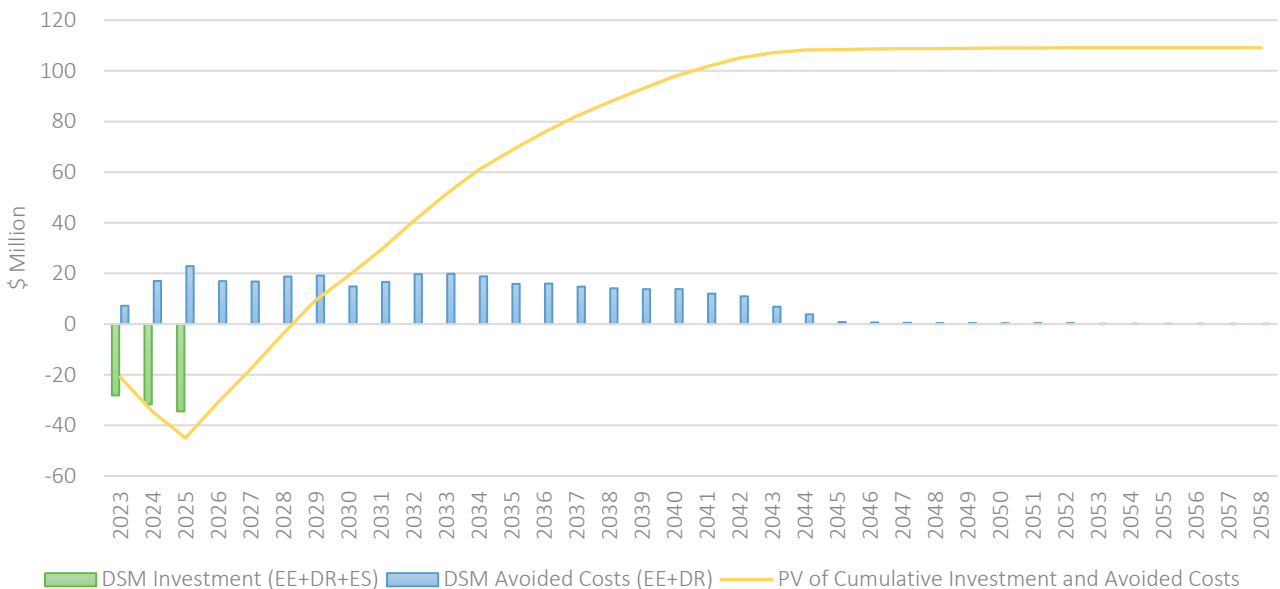
Figure 1: Residential Rate Class – Settlement Plan Payback.....	1
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SETTLEMENT PLAN RATE CLASS PAYBACK GRAPHS

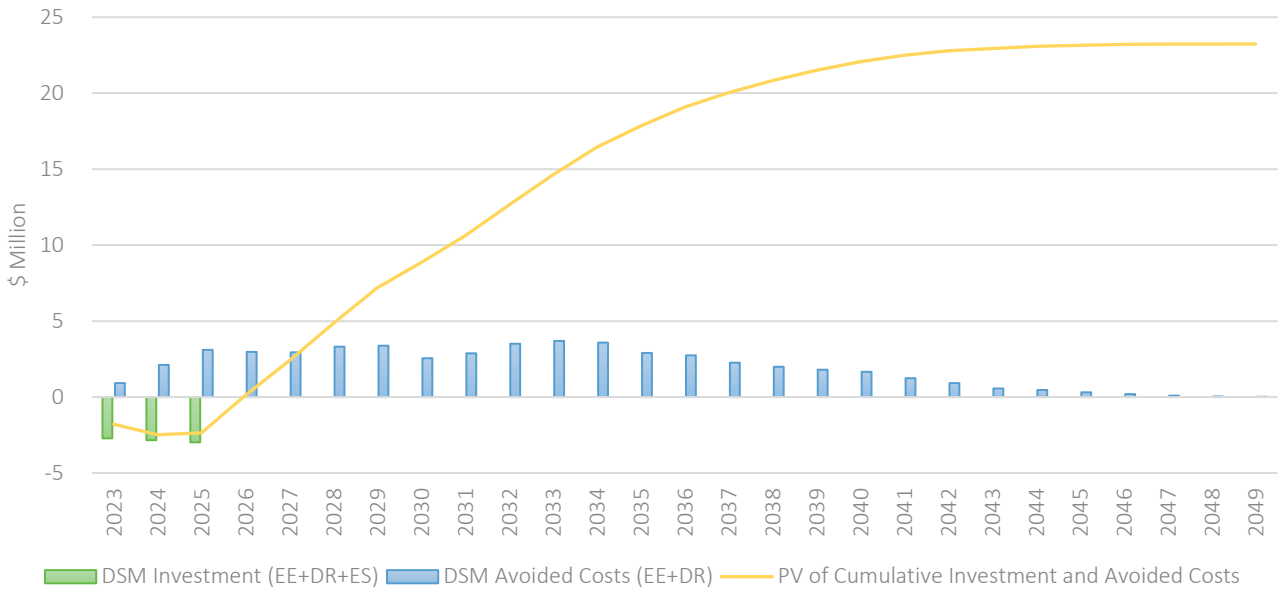
EfficiencyOne (E1) considers affordability in the development of the Settlement Plan, both short- and long-term. Payback graphs for E1's Settlement Plan for all rate classes are provided in the figures below. For all figures, the following footnotes apply:

- includes only the E1 portion of costs and benefits for 2023-2025 Demand Response (DR);
- the green bars, i.e. demand side management (DSM) investment (Energy Efficiency (EE) + DR + Enabling Strategies (ES)), are nominal investments;
- the blue bars, i.e. DSM avoided costs (EE+DR), are nominal avoided costs; and
- the yellow line, i.e. PV of cumulative investment and avoided costs, is a 2023 present value (PV) calculated using NS Power's Weighted Average Cost of Capital (WACC).

Figure 1: Residential Rate Class – Settlement Plan Payback

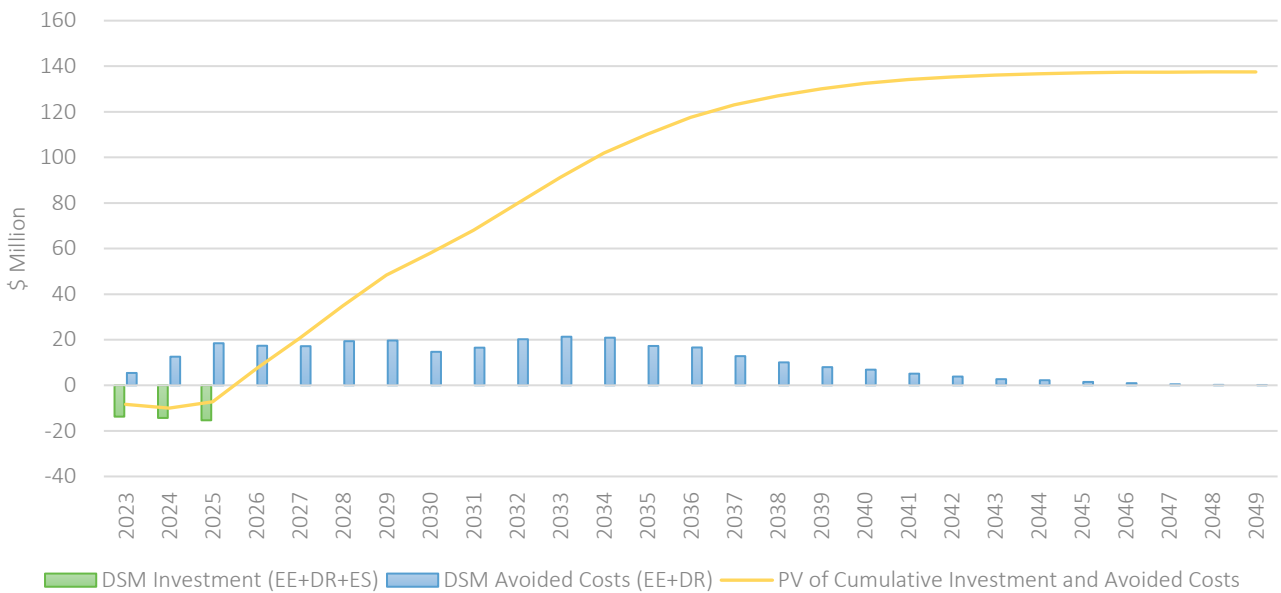


1 Figure 2: Small General Rate Class – Settlement Plan Payback

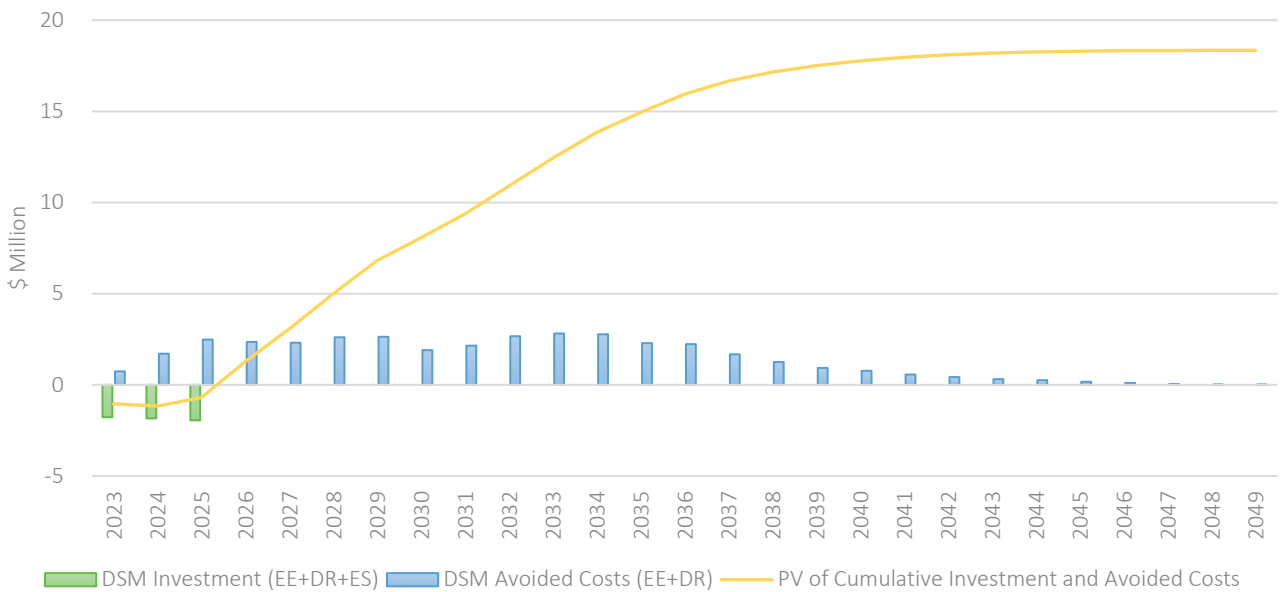


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3 Figure 3: General Rate Class – Settlement Plan Payback

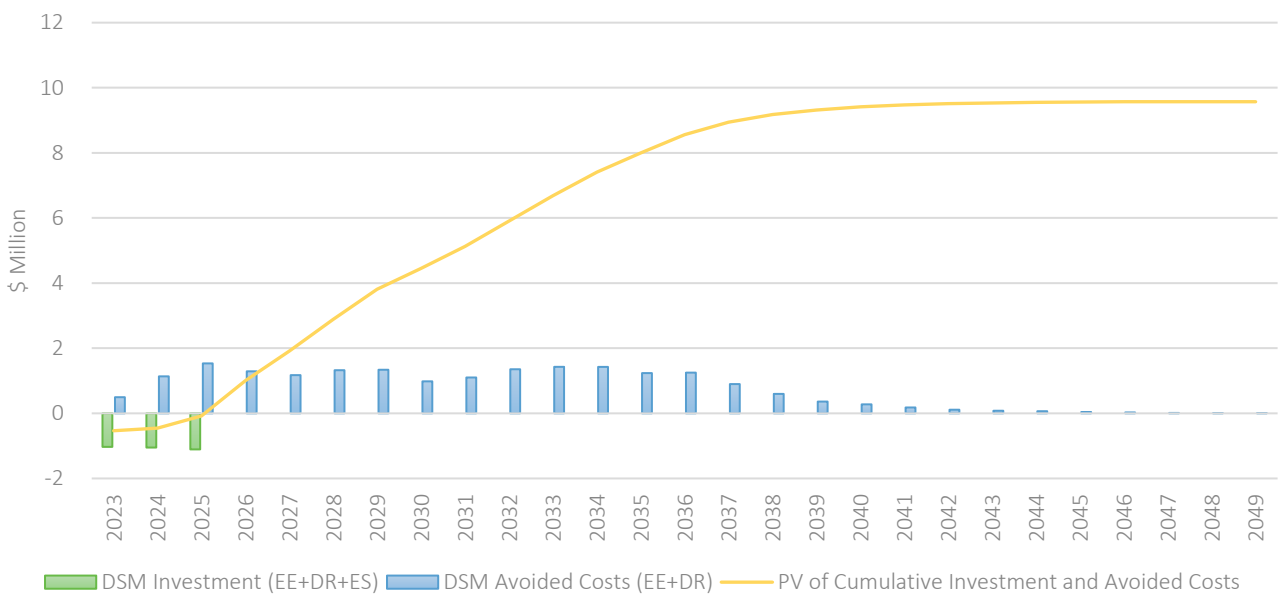


1 Figure 4: Small Industrial Rate Class – Settlement Plan Payback

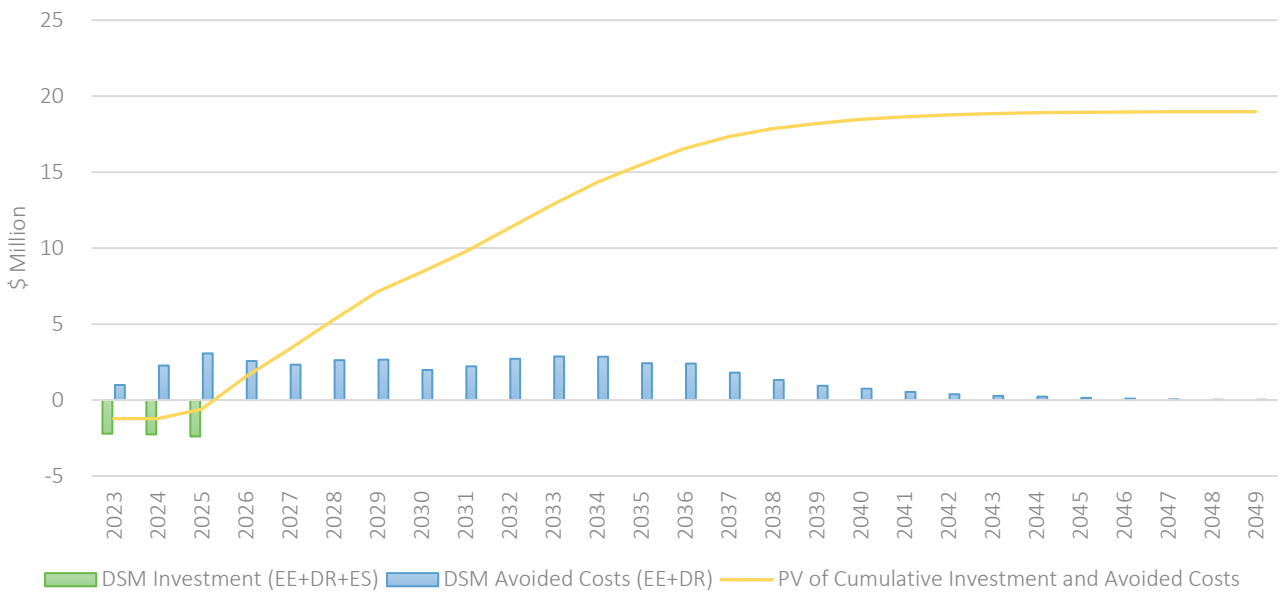


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3 Figure 5: Medium Industrial Rate Class – Settlement Plan Payback

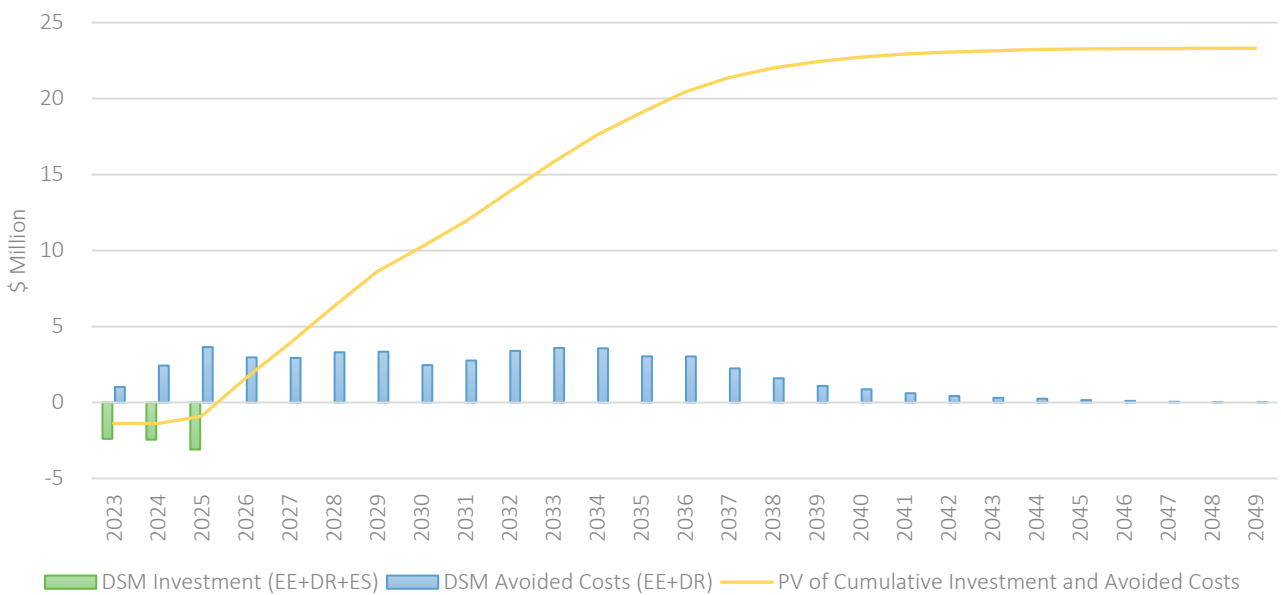


1 Figure 6: Large Industrial Rate Class – Settlement Plan Payback

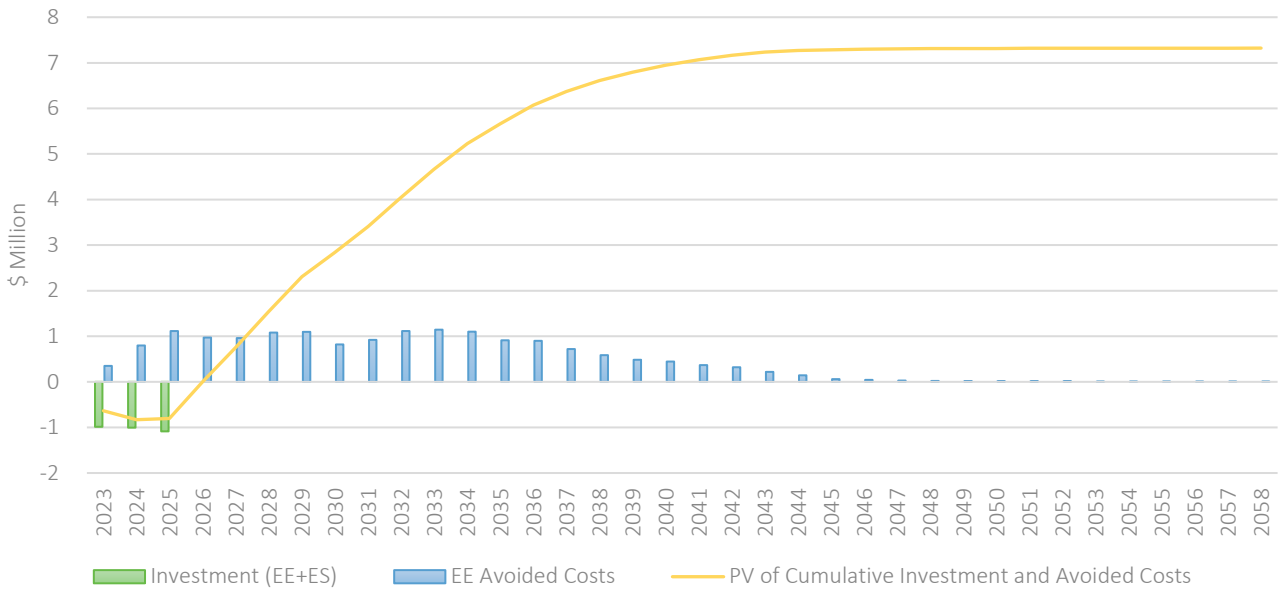


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3 Figure 7: Large General Rate Class – Settlement Plan Payback



1 Figure 8: Municipal Rate Class – Settlement Plan Payback



Appendix A

Attachment 2: Avoided Costs Brief

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DSMAG: AVOIDED COSTS SUMMARY DOCUMENT

ISSUE

The purpose of the avoided costs discussion with the Demand Side Management Advisory Group (DSMAG) was to achieve the following deliverable as described in the DSMAG Terms of Reference:

“Developing a methodology and process for ensuring current avoided costs information is regularly updated and available”

The objectives of the discussion were to obtain DSMAG consensus on the Avoided Cost Process including:

1. Definition of avoided costs for use in DSM planning in Nova Scotia;
2. Methodology used in the development of each type and instance of avoided cost estimation;
3. Timing of avoided costs updates; and
4. Final avoided costs values to be used for development of the 2023-2025 DSM Plan for May 31, 2021.

The objectives remain the same, recognizing the May 31, 2021 timeline identified in objective number four above has passed. It remains E1’s objective to resolve the remaining items related to avoided costs as soon as possible to support the 2023-2025 DSM Plan development timeline.

BACKGROUND

On March 3, 2021, the initial session on avoided costs was held with the DSMAG. Since that session the following activities have occurred:

- March 3 to March 26, 2021: Additional information requested, and questions posed by stakeholders. Responses circulated to stakeholders.
- April 7, 2021: Formal written stakeholder comments received from Synapse and NS Power.
- May 25, 2021: NS Power circulated their response to Synapse’s comments regarding energy and capacity avoided costs to the DSMAG.
- May 28, 2021: Second avoided costs session with the DSMAG.
- May 28 to June 18, 2021: Additional information requested from NS Power and responses circulated to stakeholders.
- June 25, 2021: NS Departments of Energy and Environment (DoE&E) led a meeting with E1, NS Power, Synapse, and Resource Insights Inc. (RII) on the avoided cost of carbon, specifically the federal and provincial intent beyond 2022.
- June 27 & 28, 2021: Written comments received from RII and NS DoE&E.
- July 21, 2021: Written comments received from NS DoE&E.
- July 22, 2021: Meeting with E1, Synapse, and RII to gain better understanding of positions on avoided cost of carbon.
- July 22 – August 20, 2021: Additional information requested, and questions posed by stakeholders. Responses circulated to stakeholders.
- October 12, 2021: Meeting with E1, Synapse, and RII to discuss additional questions and responses.

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AVOIDED COSTS USED BY E1 FOR ROUND 2 MODELLING OF THE 2023-2025 DSM RESOURCE PLAN

DSM PLANNING MODELS THAT USE AVOIDED COST INPUTS

- A. Energy Efficiency Process Model: The following five categories of avoided costs will be used to calculate the benefits of the energy efficiency portfolio for the 2023-2025 DSM Plan and to perform cost effectiveness testing of this component:
- Energy
 - Capacity
 - Transmission
 - Distribution
 - Carbon
- B. Demand Response DRSim Model: The following three categories of avoided costs will be used to calculate the benefits of the demand response portfolio for the 2023-2025 DSM Plan and to perform cost effectiveness testing of this component:
- Capacity
 - Transmission
 - Distribution
- C. Rate and Bill Impact Analysis (RBIA): The following five categories of avoided costs will be used for E1's RBIA on a go forward basis:
- Energy
 - Capacity
 - Transmission
 - Distribution
 - Carbon

Cost Effectiveness Screening:

- A. For the 2023-2025 DSM Resource Plan, the Total Resource Cost (TRC) test with avoided costs of carbon included will be used for program screening in building the DSM portfolio. TRC results without carbon have been provided for informational purposes only.
- B. Cost effectiveness testing have been performed for both the energy efficiency and demand response components as part of the 2023-2025 DSM Plan development process.

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AVOIDED COSTS USED IN 2023-2025 DSM PLAN MODELS

1. AVOIDED COSTS OF ENERGY

A. Energy Efficiency Process Model

E1 will use the Equivalent Escalating Series stream (AVC 2.0C NPV 2023) of avoided costs of energy as calculated by NS Power for the IRP Reference Plan (Scenario 2.0C) and provided to the DSMAG on August 20, 2021, for the energy efficiency portfolio in the 2023-2025 DSM Plan. These values are provided in Table 1 and presented as nominal:

Table 1

Year	Equivalent Escalating Series – AVC-Energy (\$/MWh)
2023	\$70
2024	\$71
2025	\$72
2026	\$74
2027	\$75
2028	\$77
2029	\$78
2030	\$80
2031	\$82
2032	\$83
2033	\$85
2034	\$87
2035	\$88
2036	\$90
2037	\$92
2038	\$94
2039	\$96
2040	\$97
2041	\$99
2042	\$101
2043	\$103
2044	\$105
2045	\$108
2046-2063	Extrapolated using 2% annual inflation

B. Demand Response DRSim Model

E1 does not intend to include avoided costs of energy in the cost effectiveness testing of demand response.

DSMAG: AVOIDED COSTS SUMMARY DOCUMENT

C. Rate and Bill Impact Analysis

E1 will use the Actual Annual AVC Energy stream (AVC 2.0C NPV 2023) of avoided costs of energy as calculated by NS Power for the IRP Reference Plan (scenario 2.0C) and provided to the DSMAG on August 20, 2021 for the E1 RBIA. These values are provided in Table 2 and presented as nominal:

Table 2

Year	Actual Annual Escalating Series – AVC-Energy (\$/MWh)
2023	\$92
2024	\$65
2025	\$77
2026	\$83
2027	\$85
2028	\$76
2029	\$76
2030	\$89
2031	\$85
2032	\$85
2033	\$85
2034	\$84
2035	\$85
2036	\$91
2037	\$94
2038	\$91
2039	\$88
2040	\$87
2041	\$96
2042	\$98
2043	\$101
2044	\$103
2045	\$102

2. AVOIDED COSTS OF CAPACITY

A. Energy Efficiency Process Model

E1 will use the Fitted Series PRM adjusted stream (AVC 2.0C NPV 2023) of avoided costs of capacity as calculated by NS Power for the IRP Reference Plan (scenario 2.0C) and provided to the DSMAG on August 20, 2021 for the energy efficiency portfolio in the 2023-2025 DSM Plan. These values are provided in Table 3 and presented as nominal:

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Table 3

Year	PRM Adjusted Fitted Series – AVC - Capacity (\$/kW-yr.)
2023	\$26
2024	\$40
2025	\$54
2026	\$67
2027	\$80
2028	\$91
2029	\$102
2030	\$112
2031	\$122
2032	\$130
2033	\$138
2034	\$145
2035	\$152
2036	\$157
2037	\$162
2038	\$167
2039	\$170
2040	\$173
2041	\$174
2042	\$176
2043	\$176
2044	\$176
2045	\$175
2046-2063	Extrapolated using 2% annual inflation

B. Demand Response DRSim Model

E1 will also use the Fitted Series PRM adjusted stream (AVC 2.0C NPV 2023) of avoided costs of capacity as calculated by NS Power for the IRP Reference Plan (scenario 2.0C) and provided to the DSMAG on August 20, 2021 for the demand response portfolio in the 2023-2025 DSM Plan. These values are outlined in Table 3 above.

C. Rate and Bill Impact Analysis

E1 will also use the Fitted Series PRM adjusted stream (AVC 2.0C NPV 2023) of avoided costs of capacity as calculated by NS Power for the IRP Reference Plan (scenario 2.0C) and provided to the DSMAG on August 20, 2021 for the E1 RBIA. These values are outlined in Table 3 above.

DSMAG: AVOIDED COSTS SUMMARY DOCUMENT

3. AVOIDED COSTS OF TRANSMISSION & DISTRIBUTION (T&D)

A. Energy Efficiency Process Model

E1 will use the system wide avoided costs of T&D as calculated by NS Power for the energy efficiency portfolio in the 2023-2025 DSM Plan. The calculated values are an outcome of resolving the remaining items that were outlined in NS Power's November 2020 T&D avoided costs filing to the UARB and are presented as a snapshot in time for the year 2021. For the 2023-2025 DSM Plan, E1 the avoided costs of T&D are extrapolated using a 2% annual inflation rate to this starting point to produce a stream of annual values. These values are provided in Table 4 and presented as nominal:

Table 4

Avoided T&D Costs – System Wide			
Year	Transmission (\$/kW-yr.)	Distribution (\$/kW-yr.)	Total (\$/kW-yr.)
2021	23.20	20.20	43.40
2022	\$23.66	\$20.60	\$44.27
2023	\$24.14	\$21.02	\$45.15
2024	\$24.62	\$21.44	\$46.06
2025	\$25.11	\$21.87	\$46.98
2026	\$25.61	\$22.30	\$47.92
2027	\$26.13	\$22.75	\$48.88
2028	\$26.65	\$23.20	\$49.85
2029	\$27.18	\$23.67	\$50.85
2030	\$27.73	\$24.14	\$51.87
2031	\$28.28	\$24.62	\$52.90
2032	\$28.85	\$25.12	\$53.96
2033	\$29.42	\$25.62	\$55.04
2034	\$30.01	\$26.13	\$56.14
2035	\$30.61	\$26.65	\$57.27
2036	\$31.22	\$27.19	\$58.41
2037	\$31.85	\$27.73	\$59.58
2038	\$32.49	\$28.28	\$60.77
2039	\$33.14	\$28.85	\$61.99
2040	\$33.80	\$29.43	\$63.23
2041	\$34.48	\$30.02	\$64.49

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Avoided T&D Costs – System Wide			
Year	Transmission (\$/kW-yr.)	Distribution (\$/kW-yr.)	Total (\$/kW-yr.)
2042	\$35.17	\$30.62	\$65.78
2043	\$35.87	\$31.23	\$67.10
2044	\$36.59	\$31.86	\$68.44
2045	\$37.32	\$32.49	\$69.81
2046-2063	Extrapolated using 2% annual inflation	Extrapolated using 2% annual inflation	–

B. Demand Response DRSim Model

E1 will use the same system wide avoided costs of T&D (provided above in Table 4) for the demand response portfolio in the 2023-2025 DSM Plan.

C. Rate and Bill Impact Analysis

E1 will use the same system wide avoided costs of T&D (provided above in Table 4) for the E1 RBIA.

4. AVOIDED COST OF CARBON METHODOLOGY & VALUES

A. Energy Efficiency PROCess Model

Throughout the past year, stakeholders have discussed a variety of methods for estimating the Avoided Cost of carbon. The primary objective of these discussions was to satisfy the UARB’s directives to improve the calculation of avoided emissions by accounting for the timing of DSM savings, and to account for the value of avoided emissions in the cost-effectiveness testing for the 2023-2025 DSM Plan. A secondary objective for E1 was to improve our methodology for calculating historical carbon reductions for publication in annual reports and marketing materials. The Avoided Cost of Carbon in year n is the product of DSM energy savings (only those which are incremental to the no-DSM scenario), carbon intensity (either an average production intensity or a marginal intensity) and the price at which carbon credits can be sold on the market.

$$AC_{carbon}^n = Savings^n \times Intensity^n \times Price^n$$

E1 understands there to be general agreement on the “Price” variable in the calculation above. At the request of the Departments of Energy and Environment a discussion was held with stakeholders where the Departments shared the intent and expectations for federal carbon pricing. As a result of this discussion, E1 will use the Federal trajectory of the cost of carbon, which is provided in Table 5. Beyond 2030, E1 has escalated the carbon price at 2% per year to account for inflation.

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Table 5

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030-2063
\$/tonne	\$30	\$40	\$50	\$65	\$80	\$95	\$110	\$125	\$140	\$155	\$170	Extrapolated using 2% annual inflation

Recent discussions have focused on the “Savings” and “Intensity” variables. After considering stakeholder feedback provided through several rounds of written comments and meetings, two general approaches have prevailed, each fully satisfying only one of the UARB’s directives:

1. **E1’s initial proposed method (October 2020)**, which accounts for the timing of reductions, but does not lend itself well to incorporation in cost-effectiveness testing, as stakeholders have pointed out that it requires the use of some form of scaling factor that would estimate what portion of DSM energy savings produce carbon reductions that are incremental to what NS Power would emit in the absence of the DSM savings, and
2. **The Difference in Carbon Emissions (DICE) method**, which directly estimates the amount of incremental carbon reductions due to DSM, and does consider the timing of generation via the construction of the with- and without-DSM 2020 Integrated Resource Plan (IRP) scenarios (i.e. 2.0C and 2.0C-No DSM), but only roughly estimates the hourly-timing of DSM savings.

E1’s initial proposed method of using historical hourly marginal generation, combined with hourly DSM savings profiles to produce measure-specific GHG intensities is a significant improvement over its current practices, and is the most appropriate means to calculate historical avoided emissions. E1 may continue to pursue acquisition of the necessary data for this purpose outside of the 2023-2025 DSM Plan proceedings. It is a logical extension of E1’s current practice of calculating avoided emissions using a single annual emissions intensity, which is the standard approach for estimating emissions reductions relating to reductions in purchased electricity.¹ NS Power, Synapse and Resource Insight all expressed concern with the application of an emissions intensity and carbon price to the entire amount of DSM savings for the purpose of cost-effectiveness testing of the 2023-2025 DSM Plan. Synapse initially characterized the desired amount of savings as the amount of “overcompliance” of the hard emissions caps, i.e. the difference between forecasted (with-DSM) emissions and hard caps. The concept has evolved to acknowledge that no-DSM comparator scenarios in the IRP also produce emissions below the cap, and that the true amount of savings to which the intensity and price should be applied is the difference in emissions between DSM and no-DSM scenarios that are otherwise the same. However, there is still value for E1 in maintaining a simple “savings times intensity” type of approach, in addition to how carbon is treated in this DSM Plan. There currently are and may always be parties that want to know the amount of carbon reductions due to DSM calculated in a way that values all DSM savings with respect to the actual generation

¹ Greenhouse Gas Protocol, “A Corporate Accounting and Reporting Standard: Revised Edition”, Appendix A

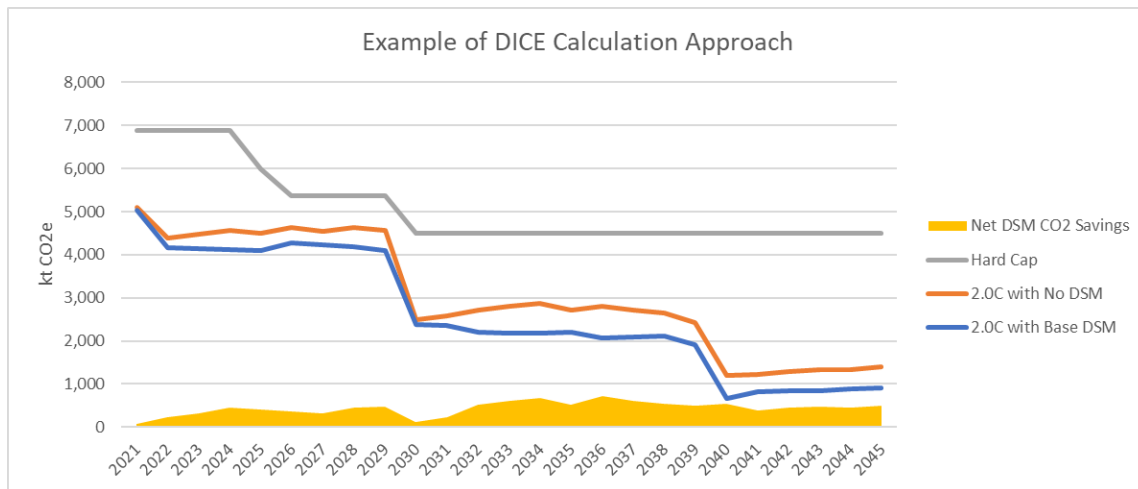
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mix of the electricity system in that year, not just those carbon reductions calculated relative to a counterfactual IRP scenario that is focused on quantifying incremental revenue generated through the Cap-and-Trade market due to DSM. E1 believes that its initial proposed method (if provided the requested source data, or some reasonable proxy that allows achievement of the same objectives) could reasonably estimate the future avoided carbon emissions from all 2023-2025 DSM savings; the key barrier to adoption of this approach for cost effectiveness testing, as identified by stakeholders, is that there is no clear way to estimate what portion of those emissions are incremental to the relevant no-DSM scenario.

The Difference in Carbon Emissions (DICE) method is similar to the treatment of avoided costs of energy. The amount of carbon reduction due to DSM is calculated by comparing the IRP carbon emissions between scenarios with and without DSM that are otherwise the same. A savings-intensity can then be developed in order to model levels of DSM that differ from what was modeled in the IRP. The IRP does to some degree optimize for hourly dispatch of generation resources, however the load shape of DSM savings in the IRP was modeled to mimic the shape of total system load. This could potentially be improved in the next IRP without deviating from the overall DICE approach; E1 could produce and share a more refined load shape (built up from the measure level for each Potential Study scenario modeled in the IRP), so that PLEXOS could more realistically dispatch generation in response to the reductions, and produce a refined estimate of the incremental emissions reductions due to DSM. This however is not a certainty; E1 would need to do some research to determine if such an approach is practically feasible, and it would require close cooperation from NS Power. An even better approach in the next IRP, in addition to more refined DSM loadshapes, would be for NS Power to model the revenue generated by the sale of carbon credits under each IRP scenario, so that this revenue stream has the ability to influence model decisions regarding generation resource acquisition and dispatch. The true avoided costs of carbon would thereby be embedded within the avoided costs of energy and capacity. The DICE method is illustrated in Figure 1 using the total emissions from IRP scenario 2.0C with Base DSM and with No DSM. Both scenarios emit below the hard cap. The difference between the scenario emissions is the net avoided emissions due to DSM, and is also shown as the shaded yellow area.

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Figure 1



An intensity can then be calculated by dividing the avoided emissions by the avoided energy consumption. This is different than E1’s initial proposed method in that it is specifically a savings-intensity, not an average consumption-intensity nor a marginal consumption-intensity. In this way it is similar to avoided energy and capacity costs, in that it accounts for the output of generation resources that were avoided due to DSM, not just the output of generation resources that actually exist at the time the DSM is delivered. Based on IRP data, the calculated intensities comparing the No DSM scenario to each of the Low, Base, Mid and Max DSM scenarios are similar for most years beyond 2022. Because the Base DSM scenario was subject to the greatest scrutiny during IRP development, E1 will apply that intensity to each modeled DSM Plan scenario. This approach is similar to the application of avoided energy and capacity costs, where the unitary avoided cost values comparing No DSM and Base DSM are applied to each of the modeled DSM scenarios. It also allows a consistent method to be used for all DSM Plan scenarios, whether or not they are identical to a Potential Study scenario. For years beyond the IRP’s termination in 2045, E1 assumed the 2045 intensity will remain the same.

Table 6 below describes the methodology options for calculating avoided costs of carbon for use in the 2023-2025 DSM Resource Plan that have been raised for discussion. The two “scaling factor” variants of the Round 1 approach were discussed in recent stakeholder meetings to represent the possibility that the full amount of DSM savings could somehow be adjusted downward to include only those which produce carbon emissions that are incremental to no-DSM scenarios. The “with TOU adjustments” variant of the DICE method is based on a suggestion from Paul Chernick of Resource Insight that the DICE method could be modified by RI or Synapse with reasonable assumptions to better estimate the impact of the timing of DSM savings, beyond the annual generation build-out timing already considered in the methodology.

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Table 6

Calculation method	Savings	Intensity
Round 1 Model approach used for 2023-2025 DSM Plan	All DSM savings	- One average production intensity per year - Future intensities calculated by dividing total emissions by Net System Requirement (NSR)
Round 1 Model approach used for 2023-2025 DSM Plan with scaling factor	Some DSM savings (amount not determined)	Same as above
E1 initial proposed approach (Oct 2020)	All DSM savings	58 measure savings profiles - Historical (3-year average) marginal emissions by hour from NSP - Combine two items above to get 58 average emissions intensities for 3-year historical average period - Forecast of IRP annual total system emission intensities from NSP - Scale 58 historical avg intensities to each future year using the ratio of future annual intensity to historical avg intensity - Extract annual savings from DSM Plan model for each measure - Sum annual Plan savings within each of 58 measure groups - Apply 58 measure-group intensities to find total avoided emissions per measure group per year - Sum emissions reductions in each year, divide total annual emissions reduction by total kWh savings to get portfolio average intensity for that year that is weighted by measure mix and measure-level timing of savings - Input these annual values into the DSM Plan model
E1 initial proposed approach (Oct 2020) with scaling factor	Some DSM savings (amount not determined)	Same as above
Difference in Carbon Emissions (DICE)	- Compare annual emissions from IRP scenarios with and without DSM - Use the DICE method carbon savings to develop emissions intensities for DSM savings, which can be used to model cost effectiveness of DSM savings levels that lie between IRP scenarios - This is the method used for Round 2 modeling	
Difference in Carbon Emissions (DICE) with TOU adjustments	- Compare annual emissions from IRP scenarios with and without DSM - Make adjustments to differences in emissions between IRP scenarios to approximate the impact of fully accounting for the timing of DSM savings - Use the DICE method carbon savings to develop emissions intensities for DSM savings, which can be used to model cost effectiveness of DSM savings levels that lie between IRP scenarios	

Faced with two imperfect options that each fully satisfy only one of the UARB's directives, E1 recommends the DICE method for use in the 2023-2025 DSM Plan. E1's initial proposed approach does a better job of

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accounting for the timing of reductions and may be used in the future for historical emissions reporting, but without a path forward to estimate the portion of carbon savings that should have a price applied to them, it cannot be incorporated in cost-effectiveness testing to the satisfaction of stakeholders. The DICE method does a reasonable job of estimating a value stream that we know exists, using a methodology that is consistent with the development of avoided energy and capacity costs, and provides an accounting framework that allows for some improvement with careful planning for the next IRP. If it can be improved further in the short term with adjustments by Resource Insight or Synapse, that would be helpful, but not critical to its adoption in the DSM Plan filing.

Using the DICE method Table 7 below provides the annual values, which are based on a comparison between IRP 2.0C with Base DSM and with No DSM.

Table 7

Year	Carbon Savings Intensity (t/MWh)
2021	0.693
2022	0.930
2023	0.861
2024	0.898
2025	0.632
2026	0.448
2027	0.355
2028	0.431
2029	0.393
2030	0.086
2031	0.159
2032	0.320
2033	0.360
2034	0.369
2035	0.269
2036	0.355
2037	0.288
2038	0.239
2039	0.218
2040	0.221
2041	0.158

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Year	Carbon Savings Intensity (t/MWh)
2042	0.175
2043	0.182
2044	0.166
2045	0.179
2046-2063	0.179

B. Demand Response DRSim Model

E1 does not intend to include avoided costs of energy or carbon in the cost effectiveness testing of demand response.

C. Rate and Bill Impact Analysis

E1 intends to use the same approach for its RBIA as it uses for cost effectiveness testing of energy efficiency programs. This will be some version of the DICE method, perhaps adjusted to better account for the timing of DSM savings.

Appendix A

Attachment 3: Guidehouse Participation Memorandum

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Memorandum

To: EfficiencyOne
From: Guidehouse
Date: February 16, 2022
Re: Forecasting DSM Plan Participation Jurisdictional Scan – Findings and Recommendations

Introduction

This memorandum presents the results of the jurisdictional scan conducted by Guidehouse to identify best practice methodologies for forecasting DSM plan participation. In conjunction with EfficiencyOne (E1), Guidehouse identified three leading North American program administrators to assess their methodology to forecast DSM plan participation. Guidehouse interviewed these administrators, and collected data from other North American program administrators (PAs) for which Guidehouse has experience supporting program design and forecasting efforts.

The interviews and research address the following topics:

- Sources of information used to forecast participation
- Data structures to codify participation estimates
- Internal review processes
- Degree of automation/human expertise and synthesis of data sources
- Predicting market volatility
- Synthesis of results, including Guidehouse perspective in a technical report

The following sections synthesize interview notes, findings, and recommendations resulting from this research, including those from Guidehouse.



Interview Summary and Key Findings

Interviews

Guidehouse conducted three interviews with program design and administration staff at leading North American DSM program administrators. Additionally, Guidehouse benchmarked the participation forecasting and incentive setting processes of PAs that Guidehouse has worked with in the development of recent DSM plans.

Table 1 lists the PAs included in the jurisdictional scan and indicates whether a formal interview was conducted. Interview notes for the interviewed PAs are summarized below, and lessons learned from other benchmark PAs are included in the key findings section.

Table 1. Summary of Jurisdictional Scan of Program Administrators

Program Administrator	Interview (Y/N)
Efficiency Maine (quasi-state agency)	Y
Efficiency Vermont (nonprofit energy efficiency utility)	Y
Wisconsin Focus on Energy (nonprofit)	Y
PECO Energy (investor-owned utility)	N
DTE Energy (investor-owned utility)	N

Efficiency Maine – Interview Summary

Efficiency Maine (EMT) operates in a unique regulatory environment with the mandate to achieve all cost-effective savings. Therefore, portfolio energy and demand requirements are not explicitly set through a formal planning process. Some programs are budget capped and reviewed in a triannual planning process, while other programs do not have budget restrictions. Although this structure differs from E1's, EMT utilizes research tools to guide forecast estimates that are applicable to E1.

The primary strategy for EMT's measure participation forecasting is internal program manager discussions. EMT leverages program manager experience in the development of forecasts, as well as incentive level setting. EMT's portfolio structure does not undergo regular large updates or transformation, so past performance is relied upon as indicative of future expectations. This is especially true for the large number of portfolio measures that account for a small portion of the total savings. For these measures, EMT utilizes simple trends or averages of past performance to develop forecasts.

For the small number of highly impactful measures that represent the majority of EMT's portfolio savings and budget, EMT conducts targeted research to understand the remaining available market in its service territory. EMT has moved to this method of periodic baseline studies for key measures in lieu of conducting and utilizing traditional exhaustive potential studies. In this way, EMT has gained an understanding of key portfolio leverage points that allow for a close approximation of total portfolio future performance.

EMT does, however, use potential studies from similar jurisdictions to estimate participation for newly added portfolio measures. These new measures are tracked closely in early phases of implementation, and forecasts are adjusted and refined continuously to account for differences in delivery channels. Once an understanding of how the new measure interacts with EMT's marketplace is developed, ongoing participation forecasting follows the methodologies described above.



Efficiency Vermont – Interview Summary

Efficiency Vermont (EVT) operates in a similar regulatory environment to E1. EVT develops 3-year plans and targets for approval with the Vermont Public Utility Commission. The primary differences between EVT's and EMT's planning process is that EVT begins research and design several years before the plan approval process, and has developed and maintained a 20-year forecast that is updated and refined during the planning period.

Like EMT's forecasting practices, EVT has found that measures of today are likely representative of the future. Therefore, trending of existing measure participation with adjustments due to codes and standards updates is the primary strategy for developing participation estimates. New measures are piloted before inclusion in the portfolio and are backed by industry research papers and manufacturer information. EVT does not heavily rely on potential studies to develop plan forecasts due to challenges with timing and differences in delivery channels. However, other studies, such as the US DOE lighting forecast, are leveraged for targeted measures.

For new measures inclusions and larger changes to portfolio objectives, EVT completes manual reviews of key performance indicators (KPIs) to develop a hierarchy of goals. The feasibility of these goals is researched with formal market assessments and discussed with program managers. Initial estimates of participation are developed through this process rather than using structured optimization to explore solutions.

Wisconsin Focus on Energy – Interview Summary

Focus on Energy (FoE) in Wisconsin is mandated to achieve a specific regulatory energy efficiency savings target for its four-year plan period determined through a Public Service Commission sponsored potential study. FoE then approaches the implementation market with those goals and budgets, and works with third-party implementation contractors to develop participation estimates and incentive levels. FoE staff work with the contractors to ensure consistency between program phases and lean heavily on the 20 years of experiential learning that the portfolio has gathered.

Generally, FoE's portfolio and programs do not differ greatly between phases, however, new measure offerings may be added. If engineering analysis and workpapers are available to support the merits of a new technology, FoE will use its Future Focus funding umbrella to complete detailed research on savings potential and delivery channels before adding a measure to programs. Additionally, implementers reach out to distributors and trade allies to gain a more granular understanding of customer adoption potential in the service territory. Starting point forecasts are set at this time and refined throughout the year as participation information is gathered.

FoE forecasts participation monthly, and conducts reviews of planned to actual on a semi-annual basis. As deviations from planned are discovered, FoE may adjust incentive levels and participation estimates to refine understanding of customer sensitivity to incentive levels. Adjustments are particularly important for weather dependent measures that may be challenging to predict.

Key Findings

There is no single best practice for program administrator (PA) participation and incentive setting processes during portfolio design. The researched utilities have demonstrated successful implementation and goal achievement through a variety of methods. Two of the interviewed PAs, EVT and EMT, have clearly defined methods for forecasting participation for portfolios that do not change significantly through time and are in similar market positions as E1, in that they design and manage implementation of their portfolios in-house. PAs such as DTE complete structured optimization modeling in the manner that E1 has in the past while FoE and PECO leverage the experience of their implementation contractors to develop participation values and set incentive levels. Select industry trending strategies are highlighted

Guidehouse Inc.

Reference No.: 218339



below and may be employed differently by each program administrator to account for differences in data availability, regulatory needs, and portfolio maturity.

1. **Minimize large portfolio changes by leveraging past performance** in the forecasting of most measures that are small contributors. This approach also reduces the need for optimization modeling if goals and constraints are not largely impacted by other portfolio KPIs.
2. **Conduct targeted research for high impact measures** to refine understanding of remaining potential, customer segmentation, and optimal delivery channels. This may include the use of implementation contractor knowledge and resources.
3. **Refine estimates for new measures through time** as preliminary data is gathered. Highly precise starting estimates for these measures that likely will not contribute a large portion of the portfolio are unnecessary and challenging.
4. **Perform structured optimization** when exploring a broad solution space to develop a starting point for portfolio development. This can be especially powerful when large portfolio changes are expected between implementation phases.
5. **Track progress and adjust forecasts** throughout implementation. It is impossible to build every possible variable into a forecasted plan. Therefore, continued review and iteration is imperative.

Interview Guide

The following questions were used to guide the interviews conducted with the three PAs (EMT, EVT, FoE). Interviews were largely free form and deviations from the guiding questions were common as utility specific nuances emerged.

1. What is your role in program planning and design?
2. How long has your organization been administering DSM programs?
3. How long is a planning phase for your utility (3-5 years?)
4. What does the planning regulatory environment look like? Who sets goals, develops plans, forecasts participants, etc.?
5. How are participation forecasts and incentive levels linked in modeling if at all?
6. How are participation forecasts and marketing or other admin spending linked in modeling if at all?
7. How do you set new measure participation?
8. How are potential studies leveraged?
9. Do you complete a retrospective to identify planned vs actual gaps? What level of aggregation defines success from a planning to implementation standpoint (measure, bundle, program, sector, portfolio)?
10. How has your approach to participation forecasting evolved over time with learnings?

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Appendix A

Attachment 4: 2023-2025 Settlement Plan Measure-level
Energy Efficiency Technical Tables

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Appendix A

Attachment 5: Guidehouse Demand Response Roadmap

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EfficiencyOne Demand Response Roadmap

Prepared for:



Submitted by:

Guidehouse Inc.

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February 25, 2022

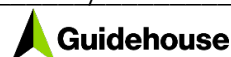


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Executive Summary

Context

Since the development of EfficiencyOne's (E1) 2020-2022 Demand-Side Management (DSM) Plan, an emerging area of interest in Nova Scotia is demand response (DR). Recently, the Nova Scotia Utility and Review Board (NSUARB) directed E1 and Nova Scotia Power Incorporated (NS Power) to explore demand response options in collaboration.¹ E1 embarked on an effort to develop a DR portfolio that would help meet NS Power's strategic objectives and develop DR as an operationally valuable resource. Additionally, from a customer perspective, DR would help expand the suite of options available to Nova Scotians to help manage their electricity usage and reduce energy costs, thereby leading to higher levels of customer satisfaction.

The purpose of the DR Roadmap is to guide E1 in developing a portfolio of DR programs that address the need for DR in Nova Scotia, identify specific DR program opportunities and their associated savings potential along with a cost-effectiveness assessment to help prioritize investment in DR, outline considerations for DR program implementation, and project a trajectory for building the DR resources.

Approach

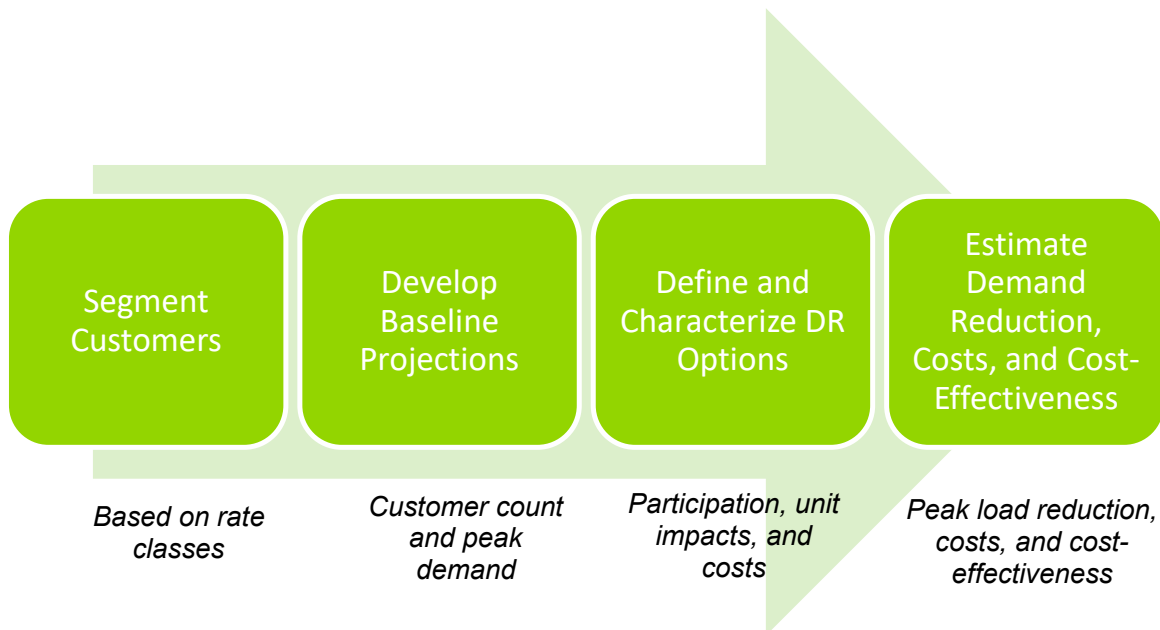
This DR assessment establishes the foundation for DR portfolio development. Therefore, a specific task under the portfolio development exercise was to assess peak load reduction estimates from different DR options that E1 could consider in its three-year portfolio plan for 2023-2025. The DR assessment is based on a bottom-up analysis that utilizes primary data from E1 and relevant secondary sources of information. The assessment was conducted using Guidehouse's DRSim™ model, which was customized for the analysis to represent E1's customer base and characteristics and considered a broad range of DR options that could apply to different market segments. Figure 1 shows the stepwise approach followed to develop peak load reduction and cost estimates for the DR roadmap.

¹ M09096, NSUARB Order, September 16, 2019. Paragraph (10).



EfficiencyOne Demand Response Roadmap

Figure 1. Roadmap Assessment Steps



The DR analysis produced MW savings and costs for two scenarios, which are the (1) Settlement Plan, and (2) Alternate Scenario. These two scenarios align with the scenarios in the energy efficiency (EE) analysis, and use the E1 2023-2025 DSM Plan EE analysis results for the baseline peak demand projections adjustments and saturation of EE-DR enabling technologies. The Alternate Scenario assumes lower levels of incentives for DR participation and consequently lower enrollment in DR programs.

Figure 2 shows the baseline peak projections by customer class (includes EVs or “electric vehicles”) after the impacts of EE as represented in the Settlement Plan. As EE savings increase in the future, peak demand is projected to decrease. It is important to note that the peak period is defined differently than in the EE scenario modelling for the E1 2023-2025 DSM Plan.²

² The baseline peak forecast represented here is different from the peak forecast by NS Power. The peak demand shown in the figure is the average peak demand over the 3-hour peak period (5 p.m. to 8 p.m.) from December through February. This serves as the baseline peak demand for estimating load reduction impacts from DR programs. Nova Scotia Power's peak forecast represents the single hour system peak demand. Therefore, the peak definition is different in the two cases. Moreover, the peak demand forecast shown in the graph represents the peak demand net of EE potential estimates from Guidehouse's analysis presented in this report, which is not incorporated in NS Power's peak demand forecast. The DR forecast also excludes Outdoor Recreational Lighting, Unmetered, General Replacement Load Following (GRLF), Real Time Pricing (RTP), Shore Power, Extra-Large Industrial Active Demand Control (ELIADC), and Mining customers since these segments tend to be ineligible for DR programs.



EfficiencyOne Demand Response Roadmap

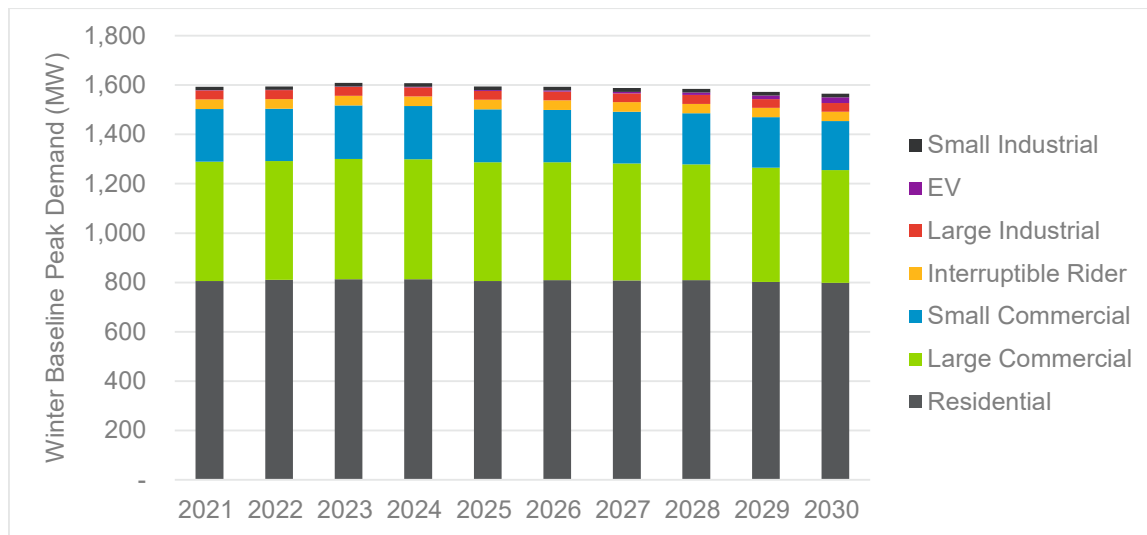
Figure 2. Winter Baseline Peak Demand by Customer Class (Settlement Plan)

Table 1 summarizes the DR options included in the study. These options are based on benchmarking with current and emerging DR options as well as existing DR pilot projects. While Time-of-Use rates do provide peak reduction, this option is not included in the DR portfolio because it is solely implemented by NS Power and out of E1's scope.

Table 1. Summary of DR Options Considered in the Study

DR Option	Description	Eligible Customer Classes	Eligible End Uses
Direct Load Control (DLC)	Control of electric loads by a thermostat and/or load control switch.	Residential Small Commercial Small Industrial	Electric Baseboard Central Heat Pump Mini-Split Heat Pump Water Heating
Business, Non-Profit & Institutional (BNI) Curtailment	Firm capacity reduction commitment. \$/kW payment based on delivered capacity, administered through third party aggregators and by NS Power.	Large Commercial Large Industrial Interruptible	HVAC Lighting Water Heating Total Facility
Behind The Meter (BTM) Battery Control	Use of batteries for load shifting and dispatching to the grid.	All classes	Batteries
EV Charging Control	Charging control to reduce EV demand during peak periods	EV	EV
Critical Peak Pricing (CPP)	A dynamic pricing option with high prices during critical peak event periods to incentivize customers to reduce load during those periods.	Residential Small Commercial Small Industrial	Total Facility



EfficiencyOne Demand Response Roadmap

DR Option	Description	Eligible Customer Classes	Eligible End Uses
Behavioural Demand Response (BDR)	DR event notification with energy savings tips, followed by post-event peer comparisons (similar to Residential Behaviour program component in EE) to motivate customers to reduce demand during DR events.	Residential	Total Facility

EE-DR Interactions

Guidehouse incorporated EE-DR interactions throughout the modeling process. To account for planned energy efficiency savings, Guidehouse subtracts the projected EE portfolio savings from the sales forecast used to develop the baseline peak forecast. In addition, Guidehouse uses the projected adoption of smart thermostats and energy management control systems (EMCS) from the EE portfolio in the DR estimation as an input to constrain the eligible customers for DLC and Commercial and Industrial (C&I) Curtailment, respectively, to only customers with the appropriate enabling technology. Per discussions with E1, Guidehouse apportioned the incremental cost of smart thermostats across the EE and DR portfolios instead of fully burdening one program with the full cost. Additionally, Guidehouse recommended an approach for EE-DR integrated cost-effectiveness.

DR Portfolio Assessment Results

The DR analysis conducted in this study covers the period 2021-2030. However, the DR savings realized for 2021-2022 winter (which would include 2021 December and January-February of 2022), can be claimed in 2022 post evaluation, measurement, and verification (EM&V) of the DR activities for the season. To represent this lag in claiming the savings, the results shown in this section consider a one-year time shift to represent the year in which savings can be claimed.

Levelized Costs and Supply Curve

As described previously, the supply curve helps determine the relative contributions from the different DR options vis-à-vis the costs for acquiring these resources. Figure 3 shows the supply curve for all DR options considered in the portfolio assessment, which includes the levelized costs on the y-axis and assumed achieved MW in 2031 on the x-axis. These costs represent Total Resource Cost (TRC) test costs and therefore do not include customer incentives in the levelized cost calculations.



EfficiencyOne Demand Response Roadmap

Figure 3. Supply Curve of DR Options for Settlement Plan

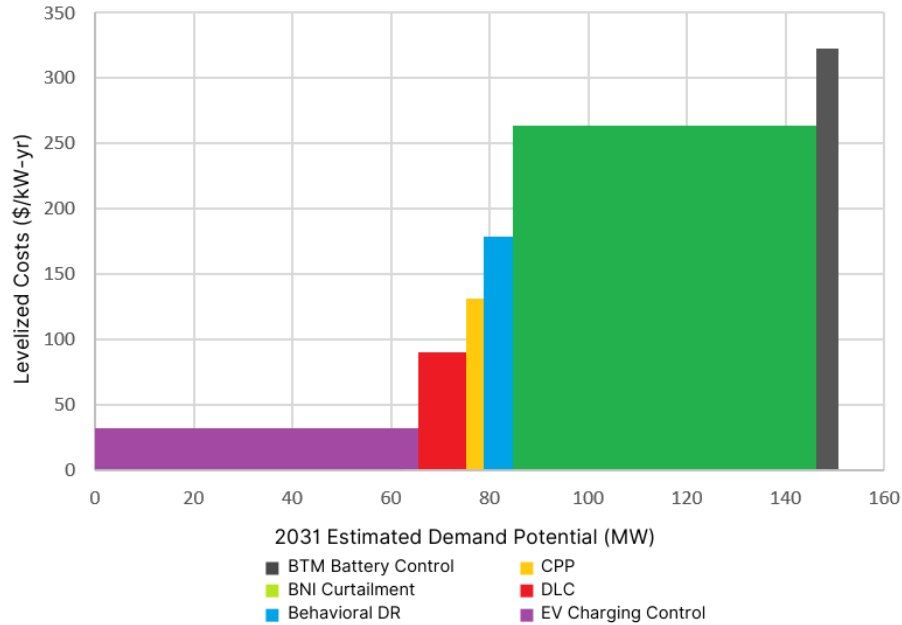
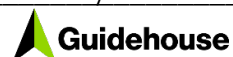


Table 2 and Table 3 show the Net Present Value (NPV) of the benefits and costs, the TRC benefit-cost ratios, and TRC levelized costs, ordered by DR option from highest to lowest benefit-cost ratio for the Settlement Plan and Alternate Scenario, respectively. The TRC benefit-cost ratio is lower and the levelized costs are higher for the Alternate Scenario than the Settlement Plan since the fixed program costs are allocated over fewer participants in the Alternate Scenario when compared with the Settlement Plan (the Alternate Scenario assumes lower participation than the Settlement Plan). The Alternate Scenario does not EV Charging Control, and Behavioural DR; therefore, these options do not appear in Table 3.

Table 2. NPV Benefits, Costs, and Benefit-Cost Ratios by DR Option for Settlement Plan

DR Option	NPV of Benefits 2021-2030 (\$ million)	NPV of Costs 2021-2030 (\$ million)	TRC Benefit-Cost Ratio	TRC Levelized Costs (\$/kW-yr.)
BTM Battery Control	\$19.37	\$3.05	6.35	\$24.72
BNI Curtailment	\$6.99	\$4.33	1.61	\$81.37
Behavioural DR	\$1.54	\$1.31	1.18	\$124.67
CPP	\$7.86	\$8.40	0.94	\$165.11
DLC	\$20.70	\$33.56	0.62	\$258.05
EV Charging Control	\$0.79	\$1.48	0.53	\$314.75
Total DR Portfolio	\$57.26	\$52.14	1.10	\$139.54

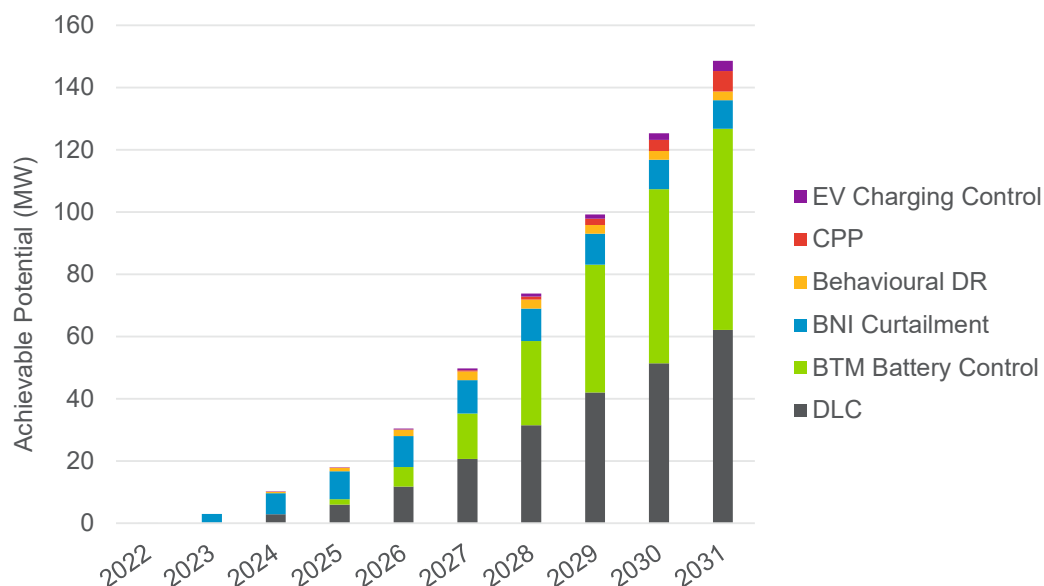


EfficiencyOne Demand Response Roadmap

Table 3. NPV Benefits, Costs, and Benefit-Cost Ratios by DR Option for Alternate Scenario

DR Option	NPV of Benefits 2021-2030 (\$ million)	NPV of Costs 2021-2030 (\$ million)	TRC Benefit-Cost Ratio	TRC Levelized Costs (\$/kW-yr.)
BTM Battery Control	\$9.69	\$2.24	4.33	\$36.27
BNI Curtailment	\$3.60	\$3.32	1.08	\$121.44
CPP	\$3.54	\$3.31	1.07	\$142.19
DLC	\$8.99	\$17.17	0.52	\$299.95
Total DR Portfolio	\$25.81	\$26.04	0.99	\$141.70

Figure 4 shows the achievable peak load reduction over time from all DR options included in the assessment for the Settlement Plan. The total peak load reduction from all E1 DR options is estimated at 18 MW by 2025 and 149 MW by 2031. BTM Battery Control and DLC have highest shares at 40% to 45% of the total. BNI Curtailment is the third largest contributor and has significantly lower share than the top two at less than 10%. The individual contribution from the other DR options is at less than 5%.

Figure 4. Peak Load Reduction from All DR Options for Settlement Plan (MW at generator)



EfficiencyOne Demand Response Roadmap

Figure 5 shows the achievable peak load reduction for 2022-2031 from all DR options included in the assessment for the Alternate Scenario. The Alternate Scenario considered a smaller set of DR options and assumed lower participation than the Settlement Plan. Consequently, estimated savings in the Alternate Scenario are 40% to 50% lower than the Settlement Plan.

Figure 5. Peak Load Reduction from All DR Options for Alternate Scenario (MW at generator)

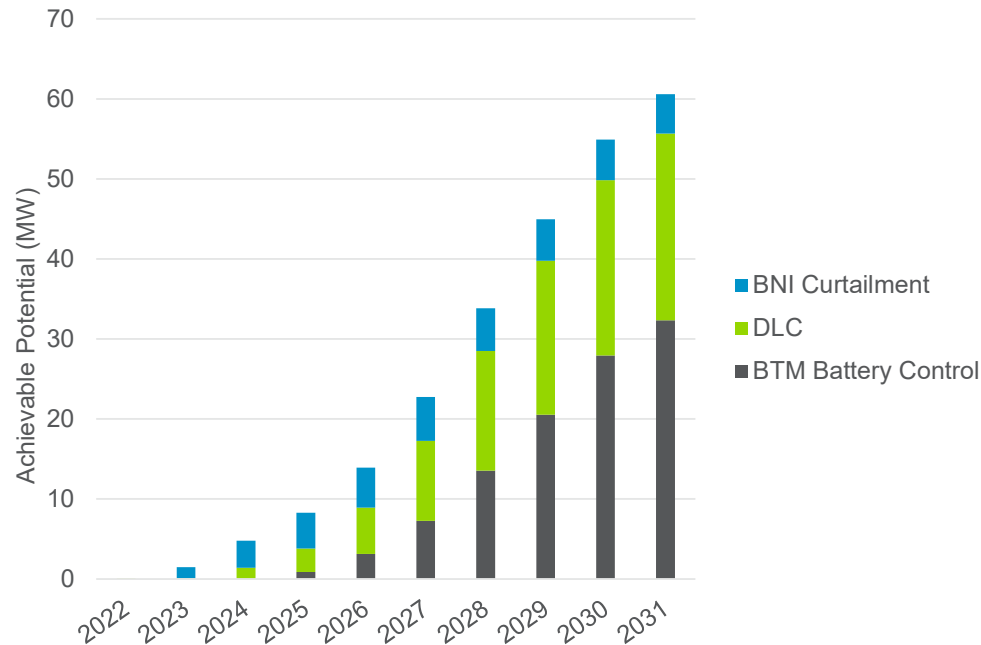
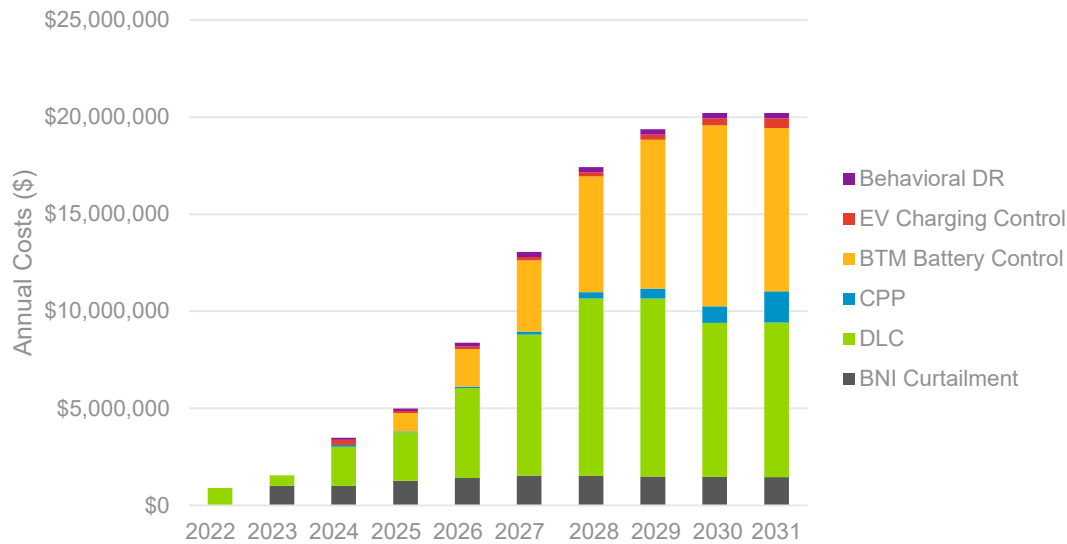


Figure 6 shows the total annual costs of the portfolio for the Settlement Plan. The E1 2023-2025 DSM Plan period costs for DR are \$10.01 million. Annual portfolio costs increase as the programs ramp up. For DLC, costs grow and then slightly decline since enabling technology costs (e.g., for smart thermostats) have a high share in the total DLC costs during the customer acquisition and the growth phase, and their share decreases over time as the programs mature, which result in a decline of the total costs for DLC. However, for other DR options, where enabling technology costs have a lower share in total costs, the overall DR option costs progressively increase over time.



EfficiencyOne Demand Response Roadmap

Figure 6. Annual E1 Costs by DR Option for Settlement Plan



Demand Response Program Delivery

DR Business Functions and E1 and NS Power Roles and Responsibilities

This section describes the core DR-related business activities and indicates E1's assumed responsibilities and NS Power's assumed responsibilities for performing these activities. The roles and responsibilities presented here are based on E1-NS Power discussions through the E1/NS Power Joint Demand Response Working Group and supported by Guidehouse's expertise in the area. Table 4 lists these functions and indicates the assumed level of responsibility for E1 and NS Power. These roles and responsibilities are likely to vary by option type.

Table 4. DR Business Functions and Assumed Responsibilities

	Business Function	Responsible Party	
		E1	NS Power
Foundation	Define Program Parameters and Initiate DR Events	Support	Perform
	Provision of DRMS/DERMS		Perform
	Marketing, Customer Recruitment & Outreach*	Perform, Support	Perform, Support
	End-use Technology Installation and Enablement	Perform	Support
Operations	Program Administration, Data and Performance Analysis	Perform, Support	Perform, Support
	Billing and Settlement	Perform	Support
Maintenance & Optimization	EM&V	Perform	Support
	Customer Service and Satisfaction	Perform	Support
	Coordination with EE programs	Perform	

*Varies by DR option type. For example, for DLC, E1 would play an active role in marketing and customer reach, whereas for CPP it would mostly be NS Power performing these activities.

In addition, the Roadmap describes an approach for integrated EE-DR program delivery.



1. Introduction

Since the development of EfficiencyOne (E1's) 2020-2022 demand-side management (DSM) Plan, an emerging area of interest in Nova Scotia is demand response (DR). While there has been little demand response activity in Nova Scotia historically, work in this area has accelerated recently, in particular by the predominant electric utility in Nova Scotia, Nova Scotia Power Incorporated (NS Power). This work includes NS Power's 2020 Integrated Resource Plan (IRP) which found that 75 MW of DR capacity was required by 2025; NS Power applied to the Nova Scotia Utility and Review Board (NSUARB) for new time-varying pricing rates with a planned rollout beginning early 2022. NS Power is installing Advanced Metering Infrastructure (AMI) province-wide with full rollout anticipated to be complete before E1's 2023-2025 DSM Plan implementation period; and the NSUARB has directed E1 and NS Power to explore demand response options in collaboration.³

Against this backdrop, E1 embarked on an effort to develop a DR portfolio that would help meet NS Power's strategic objectives and develop DR as an operationally valuable resource. Additionally, from a customer perspective, DR would help expand the suite of options available to Nova Scotians to help manage their electricity usage and reduce energy costs, thereby leading to higher levels of customer satisfaction.

E1 embarked on the current DR portfolio development and roadmap process to identify opportunities for investing in DR resources and establish a trajectory for acquiring these resources to help fulfill the DR resource acquisition objectives.

The purpose of the DR Roadmap is to guide E1 in developing a portfolio of DR programs that address the need for DR in Nova Scotia, identify specific DR program opportunities and their associated savings potential with cost-effectiveness assessment to help prioritize investment in DR, outline considerations for DR program implementation, and suggest a trajectory for building the DR resources.

Chapter 2 of this roadmap describes the approach for estimation of DR potential in Nova Scotia and the analysis. This serves as the foundation for DR portfolio development. Chapter 3 presents a DR portfolio for E1's consideration and provides high level program design with descriptions of program characteristics for the DR options included in the portfolio. Chapter 4 presents DR program implementation considerations with an outline of the roles and responsibilities of E1 and NS Power, how DR and energy efficiency (EE) could be integrated, and a discussion on DR performance metrics and associated data needs.

³ M09096, NSUARB Order, September 16, 2019. Paragraph (10).

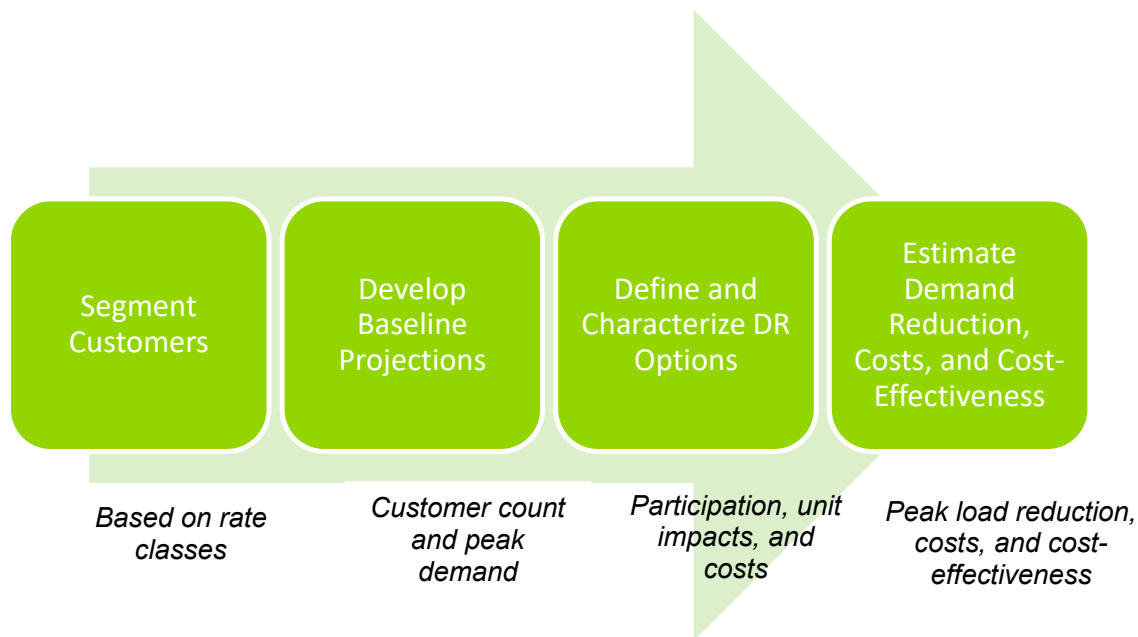
2. Demand Response Analysis Approach

DR assessment establishes the foundation for DR portfolio development. Therefore, a specific task under the portfolio development exercise was to assess peak load reduction estimates from different DR options that E1 could consider in its three-year portfolio plan. The approach for deriving these peak load reduction estimates and results are further described below.

2.1 Analysis Approach

The DR assessment is based on a bottom-up analysis that utilizes primary data from E1 and relevant secondary sources of information. The assessment was conducted using Guidehouse's DRSim™ model, which was customized for the analysis to represent E1's customer base and characteristics and considered a broad range of DR options that could apply to different market segments. Figure 7 shows the stepwise approach followed to develop peak load reduction and cost estimates for the roadmap.

Figure 7. Roadmap Assessment Steps



These steps are briefly described below.

2.1.1 Market Segmentation

Market segmentation is the first step in the DR assessment process. Table 5 presents the different levels of market segmentation for this assessment. The segmentation by customer size is based on Nova Scotia Power's electricity rate classes.

**Table 5. Market Segmentation and Applicable DR Options**

Customer Class in Analysis	Nova Scotia Power Rate Class
Residential	Residential
Small Commercial	- Small General - General (<100 kW avg. monthly peak load)
Large Commercial	- Large General - General (>=100 kW avg. monthly peak load)
Small Industrial	Small Industrial
Large Industrial	- Medium Industrial - Large Industrial
Interruptible	Interruptible Rider to the Large Industrial tariff

2.1.2 Baseline Projections

The next step after market segmentation was to develop baseline projections for the number of accounts and associated winter peak demand by customer class and segment over the DR assessment period. The baseline projections aimed to define and forecast customer data for the study period, similar to the market characterization in the EE assessment. Guidehouse selected 2020 as the base year for the study, since it is the latest year for which full market data is available at the time of the analysis. The baseline projections for the number of accounts and peak demand were developed at the following levels:

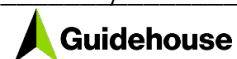
- Number of accounts
 - By customer class and building type
- Winter peak demand projections
 - By customer class, building type and end use

2.1.3 Customer Count Projections

The following steps were followed to generate customer count projections:

- Separate out Interruptible Rider customers using Business, Non-profit & Institutional (BNI) account counts by rate class
- Exclude Outdoor Recreational Lighting, Unmetered, General Replacement Load Following (GRLF), Real Time Pricing (RTP), Shore Power, Extra-Large Industrial Active Demand Control (ELIADC)
- Disaggregate 2020 NS Power Historical Rate Model customer counts using NS Power data on BNI account counts by business types
- Blend Municipal customers, assuming the same distribution as NS Power customers
- Disaggregate Residential accounts into Market Rate⁴, Low Income (LI), and Charitable Premises using NS Power data
- Use electric vehicle (EV) adoption forecast from NS Power's 2021 Load Forecast Report

⁴ All non-low-income residential customers fall under Market Rate.



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Figure 8 and Table 6 present customer count forecasts by customer class over the ten-year (2021 to 2030) study period.

Figure 8. Customer Count by Customer Class

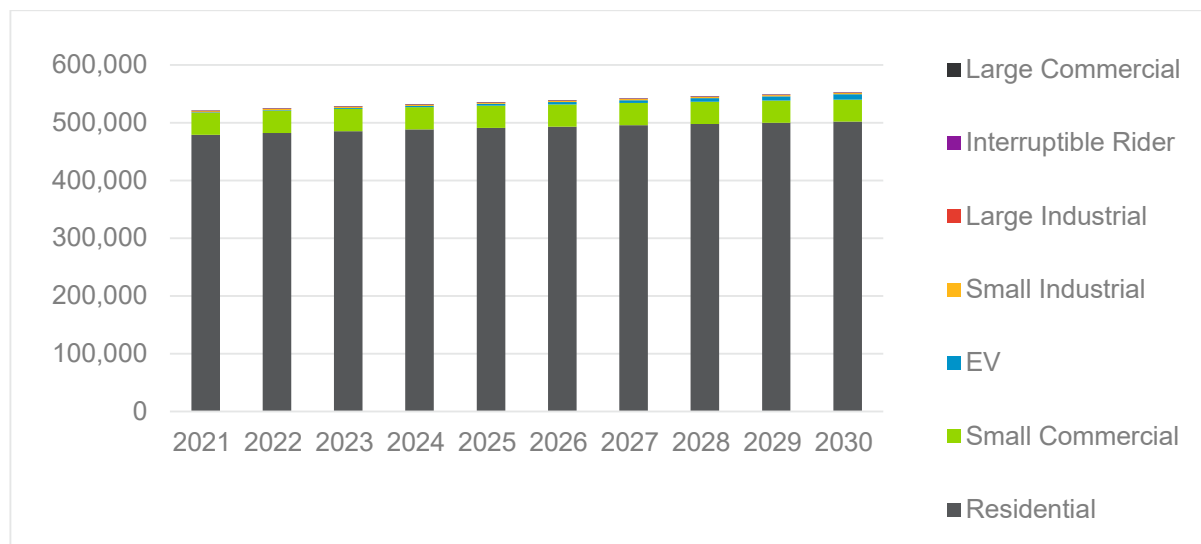
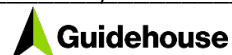


Table 6. Customer Count by Customer Class

Year	Residential	Small Commercial	EV	Small Industrial	Large Industrial	Interruptible Rider	Large Commercial
2021	478,990	38,171	413	2,136	189	23	20
2022	482,368	38,262	991	2,136	189	23	20
2023	485,431	38,386	1,807	2,136	189	23	20
2024	488,208	38,511	2,975	2,136	189	23	20
2025	490,837	38,527	4,669	2,136	189	23	20
2026	493,325	38,463	7,157	2,136	189	23	20
2027	495,670	38,404	10,853	2,136	189	23	20
2028	497,874	38,342	16,412	2,136	189	23	20
2029	499,938	38,299	24,873	2,136	189	23	20
2030	501,863	38,258	37,795	2,136	189	23	20



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Figure 9 and Table 7 present customer count forecasts by customer segment over the ten-year (2021 to 2030) study period.

Figure 9. Customer Count by Customer Segment

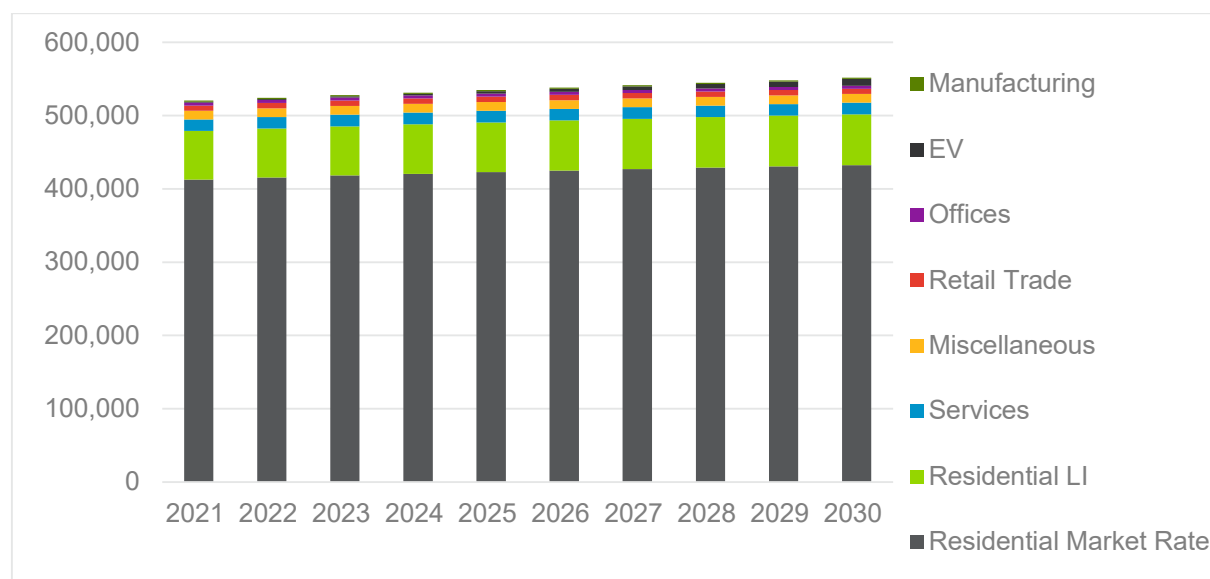


Table 7. Customer Count by Customer Segment

Year	Residential Market Rate	Residential LI	Services	Miscellaneous ⁵	Retail Trade	Offices	EV	Manufacturing
2021	412,698	66,292	15,719	11,848	7,225	4,123	886	1,624
2022	415,608	66,760	15,751	11,881	7,241	4,131	1,258	1,626
2023	418,247	67,184	15,798	11,920	7,262	4,143	1,726	1,631
2024	420,640	67,568	15,845	11,959	7,284	4,155	2,305	1,636
2025	422,905	67,932	15,848	11,969	7,285	4,156	3,063	1,637
2026	425,049	68,276	15,820	11,956	7,272	4,149	3,958	1,634
2027	427,069	68,601	15,794	11,944	7,260	4,143	5,033	1,631
2028	428,968	68,906	15,766	11,933	7,247	4,136	6,255	1,628
2029	430,747	69,191	15,746	11,926	7,238	4,131	7,627	1,626
2030	432,405	69,458	15,728	11,919	7,230	4,125	9,151	1,624

⁵ The customer segmentation follows what was considered for the “Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045; prepared for: EfficiencyOne; August 14, 2019”. The miscellaneous segment includes all BNI customers that are not classified into any of the other categories, including offices, retail trade, services, and manufacturing.



2.1.4 Peak Period Definition and Baseline Peak Demand Projections

A key element of market characterization for the DR portfolio assessment is to develop disaggregated bottom-up peak demand projections by customer class, segment and end use, which serves as the foundation for the DR portfolio estimates. Figure 10 summarizes the approach used to develop baseline peak demand projections.

Figure 10. Baseline Peak Projection Steps



The first step in this approach was to define the peak period. Based on analysis of hourly system load data, Guidehouse determined that 5-8 pm for the months of December, January, and February constitute the peak period. On average, the demand across these hours is 80% of the single hour peak. Guidehouse used this peak definition to develop coincident peak demand estimate by customer class, building type and end use. The primary data sources for developing these estimates were 8760 system data⁶, forecasted retail sales data, end-use model results from NS Power, and EE scenario results. Guidehouse used the data from these sources to develop coincident peak demand estimates by customer class and building type for the base year. Then Guidehouse projected these estimates for future years by scaling these values with the retail sales forecast. For coincident winter peak demand estimates for EVs, Guidehouse used per vehicle impacts and vehicle adoption forecasts from NS Power's 2021 Load Forecast Report.

⁶ Hourly total net Nova Scotia load from the Open Access Same-Time Information System (OASIS).
<https://www.nspower.ca/oasis/monthly-reports/hourly-total-net-nova-scotia-load>

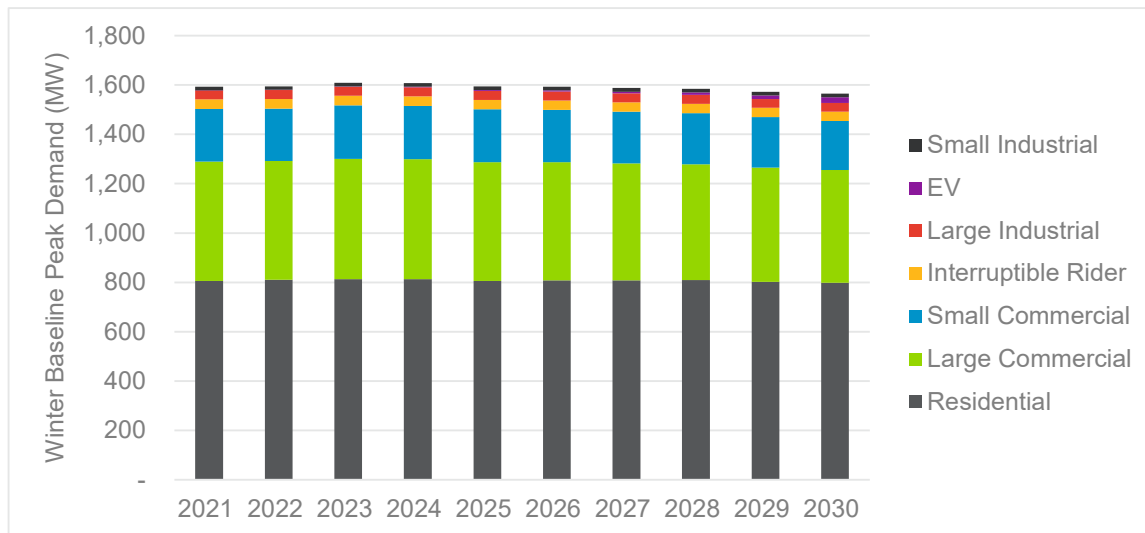


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The following figures show the baseline peak projections after the impacts of EE as represented in the Settlement Plan. As EE savings increase in the future, peak demand is projected to decrease. It is important to note that the peak period is defined differently than in the EE scenario modelling for the E1 2023-2025 DSM Plan.⁷

Figure 11 shows the estimated peak demand over the forecast period, broken out by customer class. Residential makes up the largest segment, followed by large and small commercial. The remaining customer classes – small industrial, large industrial, customers on Interruptible Rider, and EVs - constitute around 7% of the total peak demand.

Figure 11. Winter Baseline Peak Demand by Customer Class (Settlement Plan)



⁷ The baseline peak forecast represented here is different from the peak forecast by NS Power. The peak demand shown in the figure is the average peak demand over the 3-hour peak period (5 p.m. to 8 p.m.) from December through February. This serves as the baseline peak demand for estimating load reduction impacts from DR programs. Nova Scotia Power's peak forecast represents the single hour system peak demand. Therefore, the peak definition is different in the two cases. Moreover, the peak demand forecast shown in the graph represents the peak demand net of EE potential estimates from Guidehouse's analysis presented in this report, which is not incorporated in NS Power's peak demand forecast. The DR forecast also excludes Outdoor Recreational Lighting, Unmetered, GRLF, RTP, Shore Power, ELIADC, and Mining customers since these segments tend to be ineligible for DR programs.



EfficiencyOne Demand Response Roadmap

Figure 12 shows the baseline peak demand forecast broken out by customer segment.

Figure 12. Winter Baseline Peak by Customer Segment (Settlement Plan)

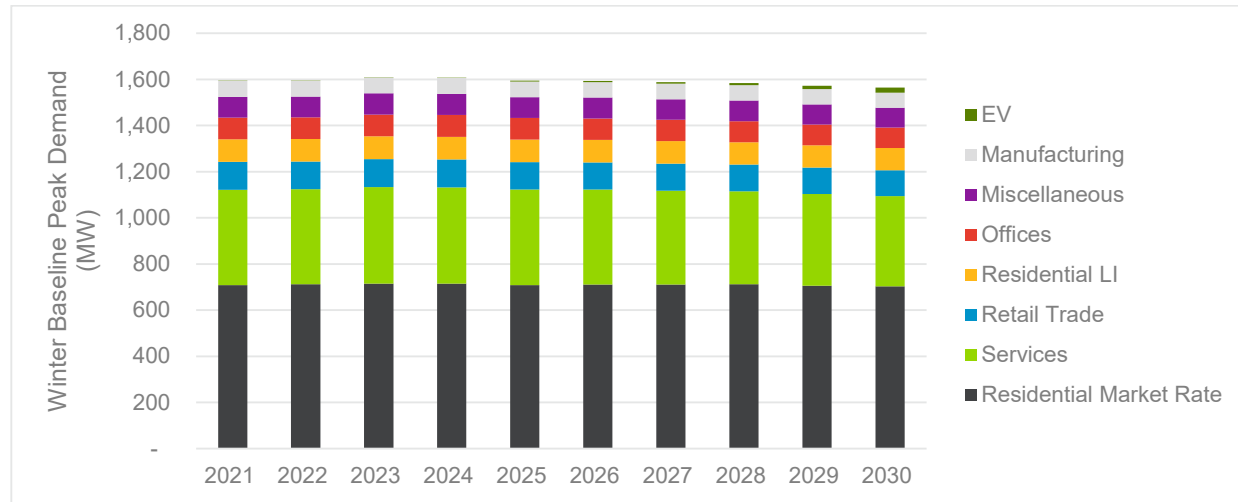
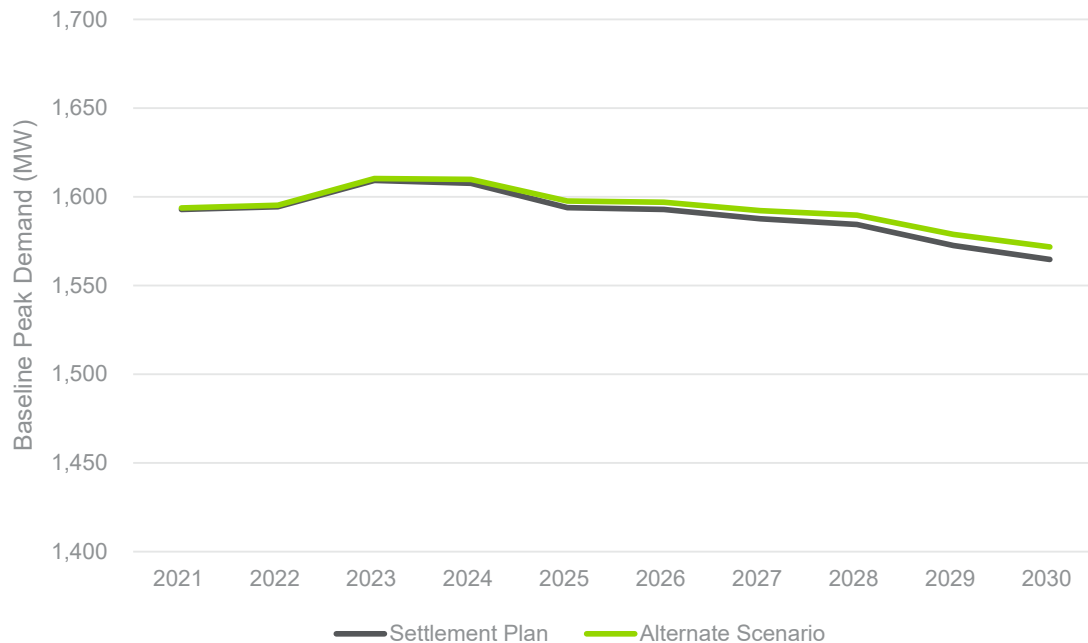


Figure 13 shows the baseline peak demand projections for the Settlement Plan and Alternate Scenario. The Alternate Scenario in the DR analysis aligns with that in the EE analysis. The baseline peak demand projections are adjusted with the EE savings from the Alternate Scenario. As is evident from Figure 13, there is minimal change in baseline peak demand between the two scenarios. The Alternate Scenario baseline peak demand is slightly higher due to lower EE savings in the Alternate Scenario vis-à-vis the Settlement Plan.

**Figure 13. Baseline Peak Demand Projections by Scenario**

2.1.5 Battery Adoption Projections

Due to a lack of information on battery adoption projections in Nova Scotia, Guidehouse developed high-level battery adoption forecasts using assumptions drawn from Guidehouse Insights reports and industry expertise.⁸

To project battery adoption by customer class, Guidehouse first estimated the size of the battery to be 5 kW and 10% of the customer demand, and the capacity to be two hours, since smaller capacities tend to be more economically feasible. Then, upfront costs and operational and maintenance (O&M) costs based on Guidehouse Insights data were used to calculate equipment costs borne by the customer. Capital costs are assumed to decline at 5% per year for the next 10 years. Annual customer bill savings were determined by obtaining demand and energy charges from NS Power tariffs and calculating the demand charge savings for BNI customers and energy arbitrage values for customers with a time-varying rate. This information was used to calculate the simple payback period for each customer class, which in conjunction with payback acceptance curves,⁹ determines the long-run equilibrium level of customer adoption. A non-economic adoption adder was added to residential customers to capture other causes of natural adoption including resiliency. The adoption was then simulated to follow a Bass-diffusion curve with a 10-year ramp rate.

⁸ Battery projections are typically an input to the DR analysis, but Guidehouse does not necessarily develop this as part of the analysis. Due to a lack of information/data on battery projections in Nova Scotia, Guidehouse developed high-level battery projections using a relatively simple approach that estimates battery adoption based on simple payback analysis. Detailed modelling of battery projections was outside the scope of the DR study.

⁹ Payback acceptance curves are based on Guidehouse studies on battery adoption for program administrators in other jurisdictions.



2.1.6 DR Options Characterization

Once the baseline peak demand projections are developed, the next step is to characterize DR options. Table 8 summarizes the DR options included in the study. These options are based on benchmarking with current and emerging DR options as well as existing DR pilot projects. While Time-of-Use (TOU) rates do provide peak reduction, this option is not included in the DR portfolio because it is solely implemented by NS Power and out of E1's scope.¹⁰

Table 8. Summary of DR Options Considered in the Study

DR Option	Description	Eligible Customer Classes	Eligible End Uses
Direct Load Control (DLC)	Control of electric loads by a thermostat and/or load control switch.	Residential Small Commercial Small Industrial	Electric Baseboard Central Heat Pump Mini-Split Heat Pump Water Heating
BNI Curtailment	Firm capacity reduction commitment. \$/kW payment based on delivered capacity, administered through third party aggregators and by NS Power.	Large Commercial Large Industrial Interruptible	HVAC Lighting Water Heating Total Facility
Behind The Meter (BTM) Battery Control	Use of batteries for load shifting and dispatching to the grid.	All classes	Batteries
EV Charging Control	Charging control to reduce EV demand during peak periods	EV	EV
Critical Peak Pricing (CPP)	A dynamic pricing option with high prices during critical peak event periods to incentivize customers to reduce load during those periods.	Residential Small Commercial Small Industrial	Total Facility
Behavioural Demand Response (BDR)	DR event notification with energy savings tips, followed by post-event peer comparisons (similar to Residential Behaviour program component in EE) to motivate customers to reduce demand during DR events.	Residential	Total Facility

¹⁰ Based on available literature, there is no empirical evidence that response to TOU rates is enhanced when coupled with enabling technologies such as smart thermostats, unlike dynamic rates such as Critical Peak Pricing. Given that, Guidehouse did not differentiate TOU impacts with and without enabling technology, and the current analysis did not separately consider TOU rates with enabling technology.



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These options were then mapped to eligible customer classes. Table 9 shows the mapping of applicable DR options by customer class.

Table 9. Customer Class and Applicable DR Options

Customer Class	DLC	BNI Curtailment	Behavioural DR	BTM Battery Control	EV Charging Control	Critical Peak Pricing	Time-of-Use Rates ¹¹
Interruptible Rider	-	√	-	√	-	-	-
Large Commercial	-	√	-	√	-	-	-
Large Industrial	-	√	-	√	-	-	-
Residential	√	-	√	√	√	√	√
Small Commercial	√	-	-	√	-	√	√
Small Industrial	√	-	-	√	-	√	√

2.1.7 Peak Load Reduction, Costs, and Cost-Effectiveness Assessment

The key inputs for peak load reduction estimation from DR are assumptions on participation rates in DR options (expressed as “% of eligible customers enrolled in DR options”) and unit load reductions (per customer load reduction expressed as either “kW reduction per customer” or as “% reduction in load”).

The savings estimates developed in the DR portfolio accounts for participation overlaps among DR options. Table 10 presents the participation hierarchy for this study, whereby achievable participation estimates are applied to eligible customers only. The participation hierarchy presented here is a well-tested approach, initially established in the *National Assessment of DR Potential Study* conducted by the Federal Energy Regulatory Commission (FERC)¹² and adopted in several other DR potential studies. The participation hierarchy helps avoid double counting of savings through common load participation across multiple DR options and is necessary to arrive at an aggregate savings estimate for the entire portfolio of DR options.

¹¹ The TOU rate represents the existing Time-of-Day (TOD) and the proposed TOU rate combined.

¹² <https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf>



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Table 10. DR Options Hierarchy to Account for Participation Overlaps

Customer Class	DR Option	Eligible Customers
Residential	DLC	Customers with eligible end-use devices
	CPP	Customers not enrolled in DLC
	TOU	Customers not enrolled in DLC or CPP
	Behavioural DR	Customers not enrolled in DLC, CPP, or TOU
	BTM Battery Control	All customers with BTM batteries
	EV Charging Control	All customers with qualified EV/electric vehicle supply equipment (EVSE)
Small Commercial, Small Industrial	DLC	Customers with eligible end-use devices
	CPP	Customers not enrolled in DLC
	TOU	Customers not enrolled in DLC or CPP
	BTM Battery Control	All customers with BTM batteries
Large Commercial, Large Industrial, Interruptible Rider	BNI Curtailment	All customers
	BTM Battery Control	All customers with BTM batteries

Source: Guidehouse

In addition to these two key inputs for peak load reduction calculations, assumptions are made on itemized program costs necessary for estimating annual program budgets and for undertaking cost-effectiveness assessment of individual DR options and the DR portfolio. These assumptions are primarily based on benchmarking with similar programs and options offered by other program administrators. Table 11 summarizes the key input variables for estimation of peak load reduction and costs for undertaking cost-effectiveness assessment.

Table 11. Key Variables for DR Savings and Cost Estimates

Item	Description
Participation Rates	Percentage of eligible customers/load that enroll in a DR Option
Unit Impacts	- kW reduction per device/customer - Reduction as % of enrolled load
Program Costs ¹³	- One-time fixed costs for program development. - One-time variable costs for customer recruitment and program marketing, equipment installation and enablement.¹⁴ - Recurring fixed and variable costs such as annual program admin. costs, customer incentives, O&M, etc.
Avoided Costs	- Avoided generation capacity costs - Avoided transmission and distribution (T&D) capacity costs
Global Parameters	Program Life, Discount Rate, Inflation Rate, Line Losses, Avoided Costs

¹³ The program costs have been assigned to E1 and NS Power based on their assumed roles.

¹⁴ The technology enablement costs for EE-DR measures such as smart thermostats are shared between EE and DR based on the Present Value (PV) of the EE and DR benefits from these measures over the measure life. The costs are split in the ratio of PV of benefits.



For assessing benefits from DR program options, the primary components are avoided generation and T&D capacity costs. The energy impacts from DR are often negligible since the energy reductions during DR events are often offset by load shaping activities before and after a DR event. For example, customers often undertake precooling/preheating of homes/premises to ride through a DR event and maintain comfort. Also, post-event snapbacks with a short-term increase in customer load are common. Both of these phenomena lead to negligible net energy impacts for DR. Additionally, storage technologies, such as batteries and water heaters (which act as thermal storage), lead to load shifting between peak and off-peak periods and do not result in net energy impacts. Therefore, avoided energy costs are not included in the benefits assessment for DR. Consequently, avoided greenhouse gas (GHG) reduction costs are also not accounted for in the benefits calculation for DR since the GHG benefits are tied to energy impacts.

Scenario Analysis

The DR analysis produced MW savings and costs for two scenarios, which are the Settlement Plan and Alternate Scenario. These align with the scenarios in the EE analysis and use the EE analysis results for the baseline peak demand projections adjustments and saturation of EE-DR enabling technologies. The Alternate Scenario assumes lower levels of incentives for DR participation and consequently lower enrollment in DR programs. Additionally, certain DR sub-options under the Direct Load Control (DLC) option that are tied to EE Direct Install measures and “CPP with enabling technology.” do not appear in the Alternate Scenario DR Portfolio since these measures are not included in the EE portfolio under the Alternate Scenario. Additionally, EV Charging Control and Behavioural DR are assumed not to be offered under the Alternate Scenario.

Treatment of Non-Energy Benefits and Costs for DR

The cost-effectiveness assessment conducted as part of the DR portfolio did not include non-energy impacts (NEIs) for DR and therefore did not quantify non-energy benefits or costs. The non-energy benefits (NEBs) and costs related to DR are briefly described below.

According to the California cost-effectiveness protocols for DR¹⁵, the three broad categories of non-energy benefits for DR include the following:

- *Social non-energy benefits*, such as environmental benefits, job creation benefits, and health benefits.
- *Utility non-energy benefits* such as fewer customer calls and improved customer relations.
- *Participant non-energy benefits*, such as “feeling green,” being good citizens by helping to prevent outages, resiliency benefits, improved ability to manage energy use, and having a better public image (for commercial enterprises).

The definitions of non-energy costs for DR primarily pertain to participant transaction costs and value of service lost from DR program participation. According to the California Public Utilities Commission’s (CPUC) cost-effectiveness protocols for DR¹⁶, transaction costs are the opportunity costs associated with education, equipment installation, program application, energy

¹⁵ <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/cost-effectiveness/2016-dr-cost-effectiveness-protocols---clean.docx>

¹⁶ <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/cost-effectiveness/2016-dr-cost-effectiveness-protocols---clean.docx>



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audits, developing and managing a load shed plan, etc. Examples of transaction costs are the personnel costs associated with time spent on activities such as filling out a DR program application, making decisions about whether or how to install DR equipment, developing and testing a load-shed plan, and enacting that plan during DR events. Value of service lost includes any losses in productivity that occur because of load reductions during DR events as well as “comfort costs,” which are the losses in comfort participants may experience or perceive when an end use becomes unavailable. These non-energy costs could be significant to the participant, but difficult to assign a monetary value. The CPUC protocol provides guidelines on estimating participant transaction costs and value of service lost as a function of the incentives provided to the customer for DR program participation.¹⁷

As stated earlier, the cost-effectiveness assessment as part of this DR portfolio did not include customer non-energy costs described above (transaction costs and value of lost service) since the Total Resource Cost (TRC) test in Nova Scotia currently does not include non-energy benefits in the benefit calculations.

The findings from the peak load reduction estimation and cost-effectiveness assessment are discussed in the next chapter.

¹⁷ According to the protocol, Load Serving Entities (LSEs) should assume that the *maximum possible* value of the transaction costs and value of service lost can be approximated as the value of all incentives paid to customers plus the customers’ total estimated bill reductions minus any participant capital costs. Because this is the *maximum* value possible for this quantity, it will be used as the high value in the sensitivity analysis for most DR programs. The base value of 75% of this quantity and a low value of 50% will be used for most DR programs.



3. Demand Response Portfolio Results

The discussion of a portfolio of DR program options for E1 outlines a strategy for acquisition and development of load management resources based on NS Power's current DR-related activities and an examination of different possibilities for future development of DR resources, which was based on a review of established and emerging DR programs offered by other program administrators. The DR Roadmap assessment, discussed in the previous chapter, establishes the foundation for E1's DR portfolio development. This chapter draws on the DR portfolio analysis results using the approach described in the previous chapter to present a suggested portfolio of DR program options and pilots for E1's consideration.

3.1 DR Portfolio Assessment Results

This section presents peak load reduction and cost estimates from the different DR options considered in the assessment and the cost-effectiveness findings for these options.

The DR analysis conducted in this study covers the period 2021-2030. However, the DR savings realized for 2021-2022 winter (which would include 2021 December and January-February of 2022), can be claimed in 2022 post EM&V of the DR activities for the season. To represent this lag in claiming the savings, the results shown in this section consider a one-year time shift to represent the year in which savings can be claimed.

This section first discusses the supply curve results from the analysis, which shows the 2031 peak load reduction estimates vs. the levelized costs for all DR options, and the benefit-cost ratio for each option based on the cost-effectiveness results. It then presents annual achievable peak load reduction estimates from all DR options included in the analysis, and separately calls out peak load reduction estimates from cost-effective DR options only. The peak load reduction results are shown by customer class, which help determine the relative contributions of different customer segments toward the total peak load reduction.

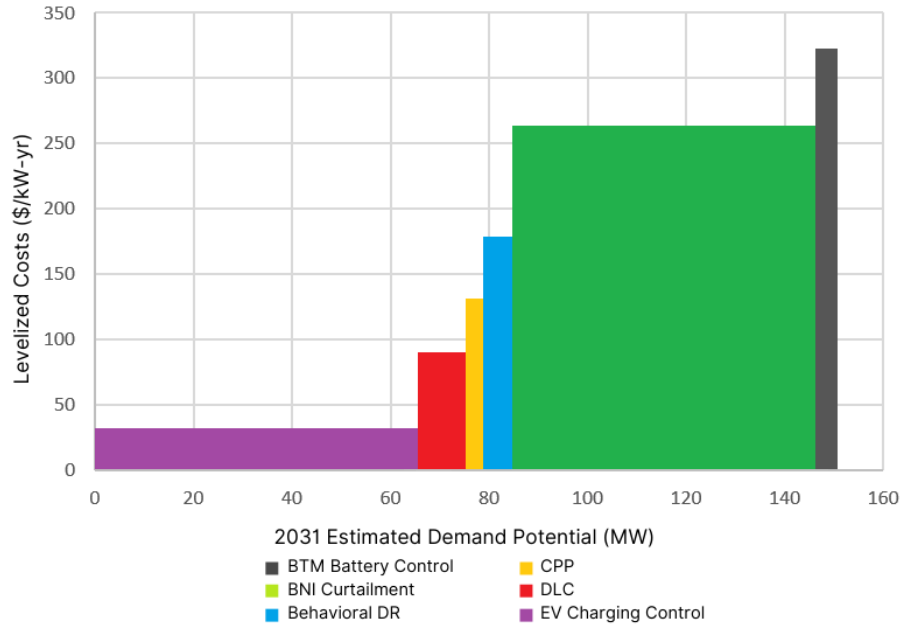
3.1.1 Levelized Costs and Supply Curve

As described previously, the supply curve helps determine the relative contributions from the different DR options vis-à-vis the costs for acquiring these resources. Figure 14 shows the supply curve for all DR options considered in the portfolio assessment, which includes the levelized costs on the y-axis and assumed achieved MW in 2031 on the x-axis. These costs represent TRC costs and therefore do not include customer incentives in the levelized cost calculations.



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Figure 14. Supply Curve of DR Options for Settlement Plan



BTM battery control is the least cost option and provides around 65 MW of peak demand savings in 2031. DLC (including both Bring Your Own and Direct Install options) has the next highest contribution in savings at 62 MW in 2031 but is the second most expensive option after EV charging control. Third highest contribution is from BNI Curtailment at around 10 MW peak demand savings in 2030 and it ranks second to BTM battery control in terms of ascending levelized costs. Other DR options have relatively small contribution. The savings from CPP are those that are attributable to the enabling technology portion only, since E1 would be able to claim only that portion of the CPP savings.



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Table 12 and Table 13 show the Net Present Value (NPV) of the benefits and costs, the TRC benefit-cost ratios, and TRC levelized costs, ordered by DR option from highest to lowest benefit-cost ratio for the Settlement Plan and Alternate Scenario, respectively. The TRC benefit-cost ratio is lower and the levelized costs are higher for the Alternate Scenario than the Settlement Plan since the fixed program costs are allocated over fewer participants in the Alternate Scenario when compared with the Settlement Plan (the Alternate Scenario assumes lower participation than the Settlement Plan). The Alternate Scenario does not EV Charging Control, and Behavioural DR; therefore, these options do not appear in Table 13.

Table 12. NPV Benefits, Costs, and Benefit-Cost Ratios by DR Option for Settlement Plan

DR Option	NPV of Benefits 2021-2030 (\$ million)	NPV of Costs 2021-2030 (\$ million)	TRC Benefit-Cost Ratio	TRC Levelized Costs (\$/kW-yr.)
BTM Battery Control	\$19.37	\$3.05	6.35	\$24.72
BNI Curtailment	\$6.99	\$4.33	1.61	\$81.37
Behavioural DR	\$1.54	\$1.31	1.18	\$124.67
CPP	\$7.86	\$8.40	0.94	\$165.11
DLC	\$20.70	\$33.56	0.62	\$258.05
EV Charging Control	\$0.79	\$1.48	0.53	\$314.75
Total DR Portfolio	\$57.26	\$52.14	1.10	\$139.54

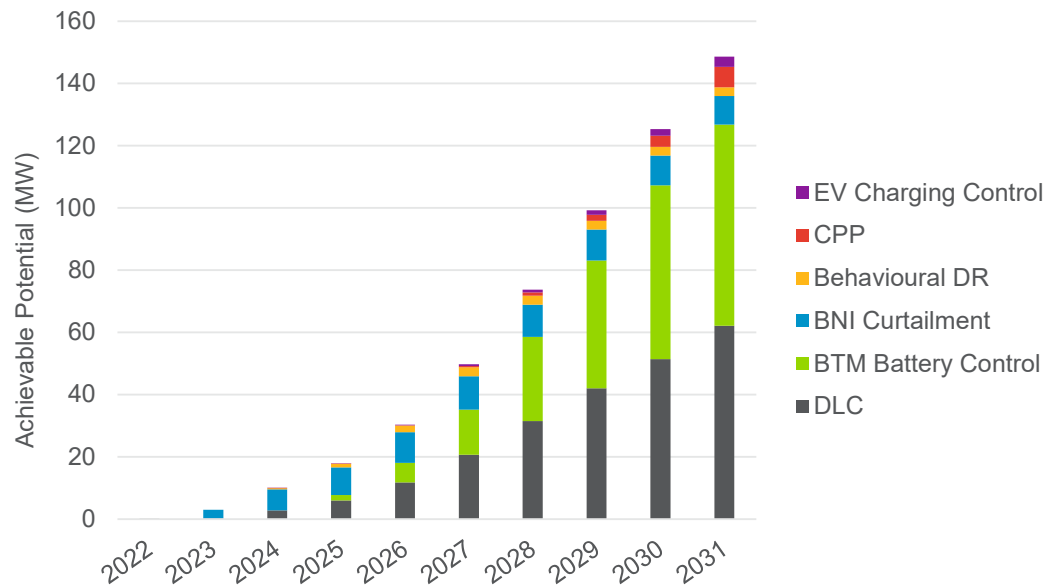
Table 13. NPV Benefits, Costs, and Benefit-Cost Ratios by DR Option for Alternate Scenario

DR Option	NPV of Benefits 2021-2030 (\$ million)	NPV of Costs 2021-2030 (\$ million)	TRC Benefit-Cost Ratio	TRC Levelized Costs (\$/kW-yr.)
BTM Battery Control	\$9.69	\$2.24	4.33	\$36.27
BNI Curtailment	\$3.60	\$3.32	1.08	\$121.44
CPP	\$3.54	\$3.31	1.07	\$142.19
DLC	\$8.99	\$17.17	0.52	\$299.95
Total DR Portfolio	\$25.81	\$26.04	0.99	\$141.70

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Figure 15 shows the achievable peak load reduction over time from all DR options included in the assessment for the Settlement Plan. The total peak load reduction from all E1 DR options is estimated at 18 MW by 2025 and 149 MW by 2031. BTM Battery Control and DLC have highest shares at 40% to 45% of the total. BNI Curtailment is the third largest contributor and has significantly lower share than the top two at less than 10%. The individual contribution from the other DR options is at less than 5%.

Figure 15. Peak Load Reduction from All DR Options for Settlement Plan (MW at generator)

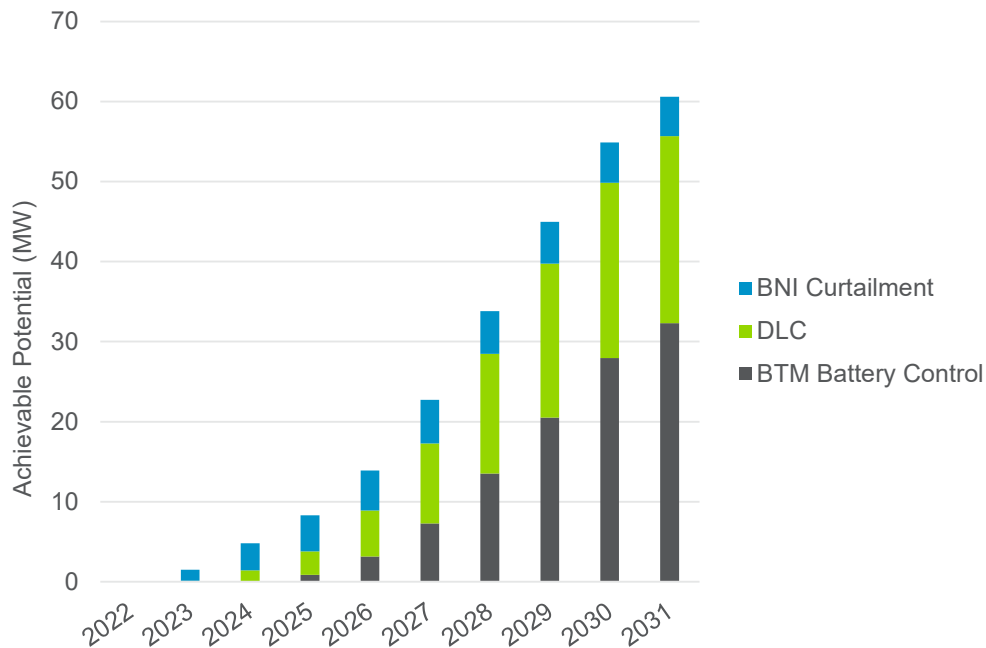




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Figure 16 shows the achievable peak load reduction for 2022-2031 from all DR options included in the assessment for the Alternate Scenario. As discussed previously, the Alternate Scenario considered a smaller set of DR options and assumed lower participation than the Settlement Plan. Consequently, estimated savings in the Alternate Scenario are 40% to 50% lower than the Settlement Plan.

Figure 16. Peak Load Reduction from All DR Options for Alternate Scenario (MW at generator)





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Figure 17 shows the customer class shares in the total achievable peak load reduction in 2025 for the Settlement Plan. Figure 18 shows the applicable DR options for each customer class which lead to the peak load reduction estimated for these classes.

Figure 17. Customer Class Shares in Estimated 2025 DR Savings for Settlement Plan

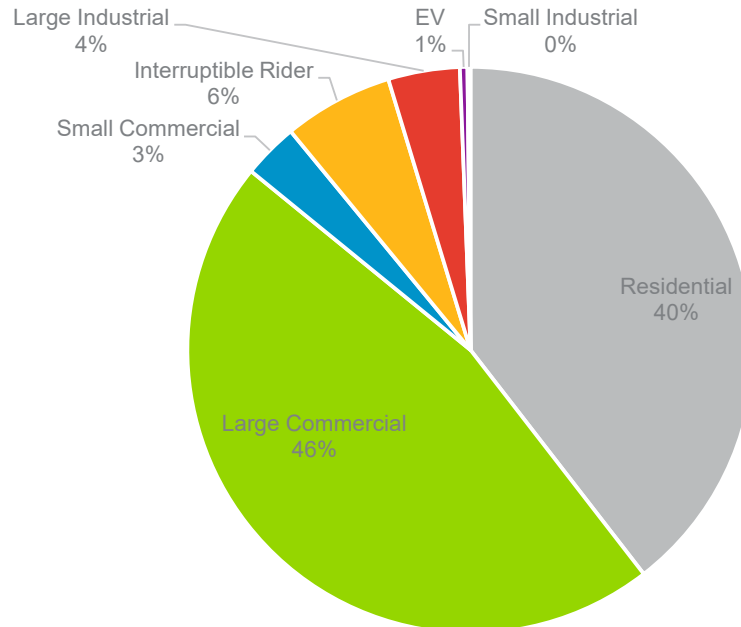
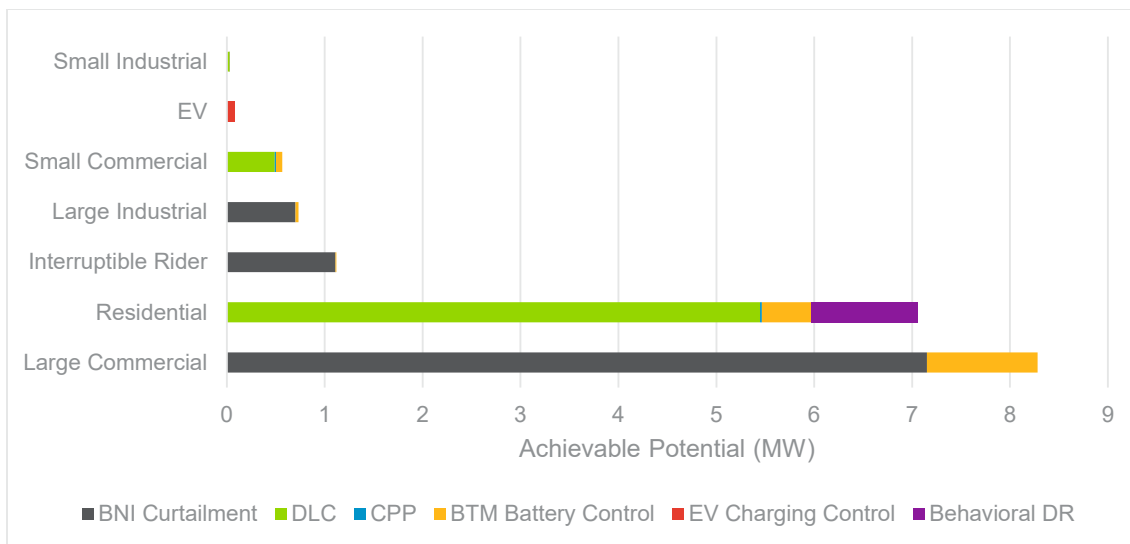


Figure 18. 2025 DR Savings by Customer Class and DR Option for Settlement Plan



The Large Commercial and Residential classes are the two largest contributors to the total peak load reduction in 2025. DLC and BNI curtailment comprise the majority of the Residential and Large Commercial segments, respectively.

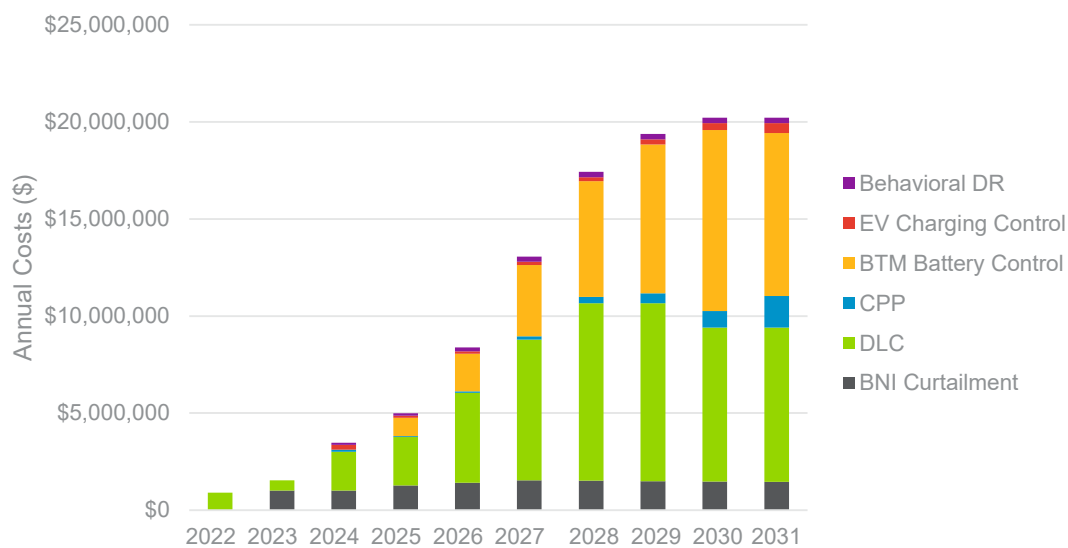


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The next section describes the DR options in greater detail and presents the planned DR portfolio for E1.

Figure 19 shows the total annual costs of the portfolio for the Settlement Plan. The E1 2023-2025 DSM Plan period costs for DR are \$10.01 million. Annual portfolio costs increase as the programs ramp up. For DLC, costs grow and then slightly decline since enabling technology costs (e.g., for smart thermostats) have a high share in the total DLC costs during the customer acquisition and the growth phase, and their share decreases over time as the programs mature, which result in a decline of the total costs for DLC. However, for other DR options, where enabling technology costs have a lower share in total costs, the overall DR option costs progressively increase over time.

Figure 19. Annual E1 Costs by DR Option for Settlement Plan

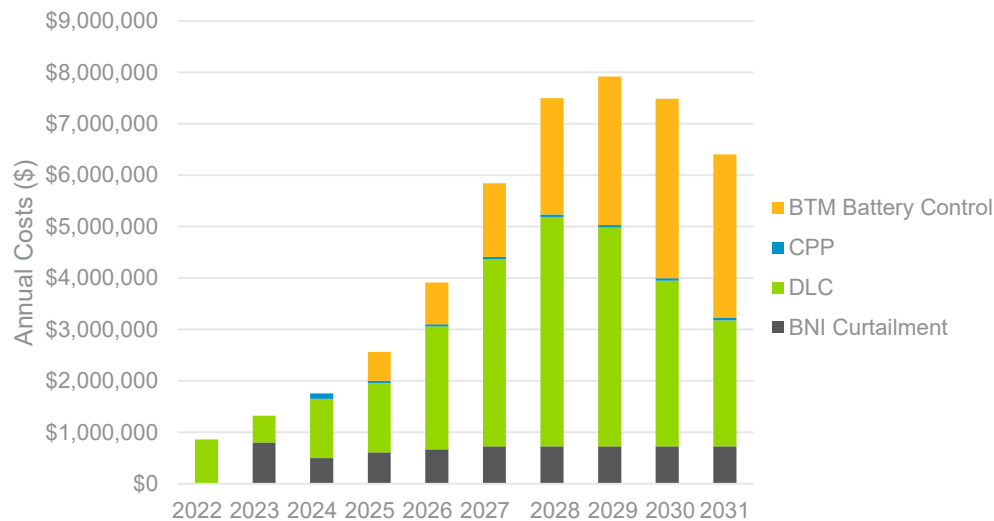




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Figure 20 shows the total annual costs of the portfolio for the Alternate Scenario. The 2023-2025 Plan period costs are \$5.65 million.¹⁸

Figure 20. Annual E1 Costs by DR Option for Alternate Scenario



¹⁸ The Alternate Scenario does not include any CPP impacts since E1 does not plan to incentivize Direct Install smart thermostat measures in the Alternate Scenario. However, note that the Alternate Scenario includes CPP costs. The reason for that is there are certain common costs related to setting up the CPP offer and administering it, plus conducting customer outreach and education activities that the CPP option bears regardless of whether CPP is offered as a rate-only option or paired with enabling technology. So, even though CPP impacts with enabling technology do not exist in the Alternate Scenario, that E1 could claim savings for, the CPP costs accrued are due to cross promotion of flexible demand measures in Instant Savings/Small Business Energy Solutions/Business Energy Rebates with CPP, and education and outreach on the CPP rate.



EfficiencyOne Demand Response Roadmap

Figure 21 shows an itemized breakdown of the annual E1 portfolio costs for the Settlement Plan. Incentives consistently constitute the highest share in costs, comprising an increasing percentage with time. As previously noted, technology enablement costs have relatively higher shares in the total annual costs during the program ramp up phase, and then decrease as programs mature. Program administrative and development costs similarly increase, and then decrease.

Figure 21. Itemized Annual E1 DR Portfolio Costs for the Settlement Plan

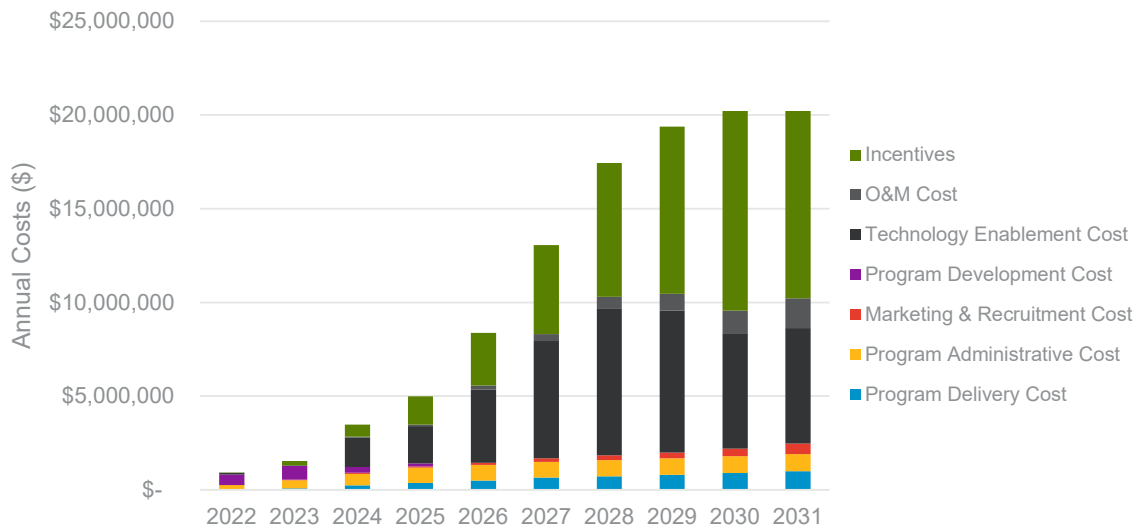
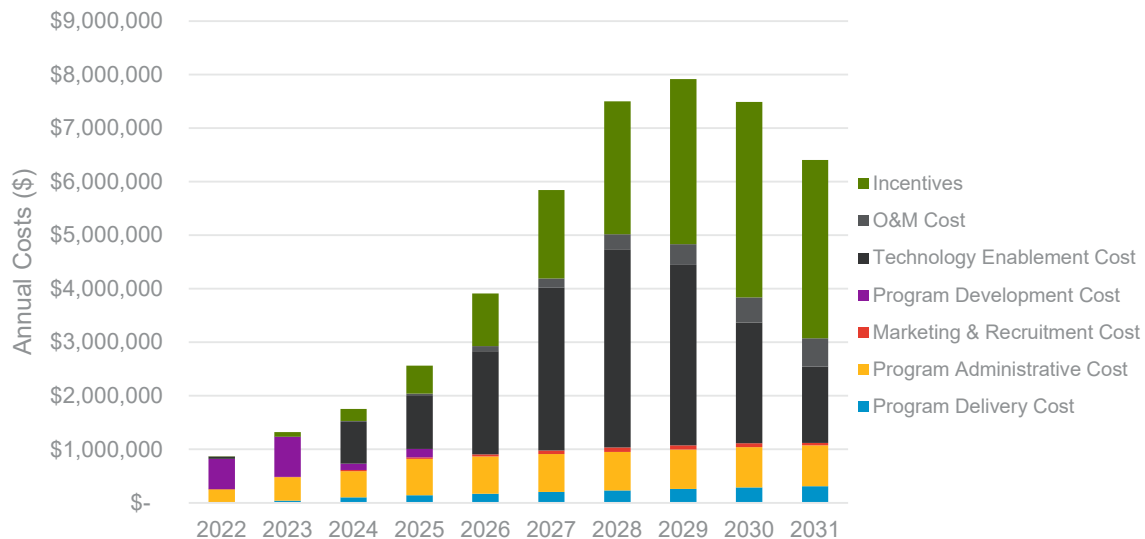


Figure 22 shows an itemized breakdown of the annual portfolio costs for the Alternate Scenario.

Figure 22. Itemized Annual E1 DR Portfolio Costs for the Alternate Scenario





3.2 Summaries by DR Option¹⁹

This section presents detailed summaries for each DR option. The savings and costs discussed in this section are for the Settlement Plan.

3.2.1 Direct Load Control (DLC)-Thermostat (BYOT and DI)

The 2023-2025 DR Portfolio includes a Direct Load Control (DLC) option with both Bring-Your-Own-Thermostat (BYOT) and Direct Install (DI) delivery approaches. BYOT applies to residential, small commercial, and small industrial customers with Wi-Fi thermostats and is expected to provide approximately 0.39 MW of load reduction by 2025. In the DI approach, customers are provided with free installed thermostats, and this is expected to provide approximately 0.10 MW of load reduction by 2025. These estimates are based on the analysis discussed in the previous chapter. Approximately 90 percent of the total reduction is expected to be realized from residential customers, with the remaining 10 percent from small commercial and industrial (C&I) customers. Table 14 presents a high-level design and outlines the key characteristics.

Table 14. DLC Thermostat-BYOT and DI Characteristics

Item	Description
Program Description	- Direct Load Control option to customers with Wi-Fi enabled smart thermostats, where customer electric space heating is controlled during DR events, typically using a temperature reset strategy. - Under BYOT, E1 would contract with a BYOT service provider, where multiple smart thermostat brands are controlled using the provider platform. - Residential customers receive smart thermostat rebates offered by E1 as part of the Efficient Product Rebates-Instant Savings component and enroll these thermostats in the BYOT component of the DLC option. - Small Commercial and Small Industrial customers receive smart thermostat rebates offered by E1 as part of the Efficient Product Rebates-Business Energy Rebates component and enroll these thermostats in the BYOT component of the DLC option. - Under the DI approach, smart thermostats are installed at no-cost to customers enrolled in this option. - Residential customers receive direct install smart thermostats, at no-cost, through the Efficient Product Installation component of the Existing Residential program. - Small Commercial and Small Industrial customers receive direct install smart thermostats, at no-cost, through the Small Business Energy Solutions component of the Direct Installation program.

¹⁹ The savings and costs for the years indicated in the option summary tables in this section represent the potential demand savings and cost results for DR activities incurred in the prior year. These years represent when the savings could be claimed and are shown for reporting purpose only.



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Item	Description
Eligible Customers	Residential, small commercial, and small industrial customers with central heat pumps (HP), mini-split heat pumps (MSHP), or baseboard heaters and with smart thermostats to control the different equipment types.
Program Enrollment Assumptions	- Steady state participation levels²⁰ range from 10% to 50% of eligible customers depending on the customer segment and the type of delivery (BYOT and DI). - Eligible customers are those that receive a rebate on a smart thermostat purchase or receive a direct installed smart thermostat through EE programs. - Residential and Small C&I participation ramp - Ramps up to 15% of steady state participation level by 2023 - Ramps up to 39% of steady state participation level by 2025
Program Parameters	<i>The key parameters are listed below with initial assumptions, subject to further revisions during the detailed design stage prior to launch.</i> Operating Months - Winter peak reduction (Dec. through Feb.) - Events may be called anytime, all year round to address system emergencies and to help meet operating reserve requirements Event Window - Winter peak period (5-8 pm) - Operating reserves and system emergencies (anytime and all-year round) Event Notification - Depends on the thermostat provider - Customers may be allowed advance notification for preheating their homes Event Duration: Max. 3 hours; average 2 hours Max. total event hours: 40 hours during winter (Dec. through Feb.)
	Unit Impacts - Residential - Central HP (only considered under Direct Install approach): 1.21 kW/thermostat, 1 thermostat/participant, which translates to 1.21 kW/participant. - Baseboard and MSHP: 0.2 kW/thermostat, 2.5 thermostats/participant, which translates to 0.5 kW/participant. - Small C&I - Central HP (only considered under Direct Install approach): 1.21 kW/thermostat, 2 thermostats/participant, which translates to 2.42 kW/participant. - Baseboard and MSHP: 0.2 kW/thermostat, 5 thermostats/participant, which translates to 1 kW/participant.
Unit impacts (kW reduction per thermostat)	

²⁰ Represents participation levels in mature programs after an option is fully ramped up.



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Item	Description
Participation Incentives	- Residential - Central HP: \$25/new participant (one-time enrollment), \$50/participant/yr. annual participation incentive. - Baseboard and MSHP: \$5/new participant (one-time enrollment), \$10/yr. existing participant (annual participation incentive) - Small C&I - Central HP: \$50/new participant one-time enrollment incentive, \$100/participant/yr. annual participation incentive. - Baseboard and MSHP: \$10/new participant (one-time enrollment), \$20/participant/yr. (annual participation incentive)
Projected Load Reductions and Costs²¹	0.5 MW projected peak load reduction in 2025 - Cumulative E1 costs for DLC using smart thermostats over 2023-2025 are estimated at around \$443.3k

3.2.2 Direct Load Control (DLC)-Water Heater (BYOD and DI)

The 2023-2025 DR Portfolio includes a Bring Your Own Device (BYOD) controllable water heater and Direct Install (DI) water heater switch option to residential and small C&I customers. This option is expected to provide approximately 5.5 MW of load reduction by 2025. These estimates are based on the analysis discussed in the previous chapter. Approximately 80-95% of the total reductions is expected to be realized from residential customers and the remaining from small C&I customers. Table 15 presents a high-level design and outlines the key characteristics.

Table 15. DLC Water Heater-BYOD and DI Characteristics

Item	Description
Program Description	- Direct Load Control option that controls electric water heater during peak demand periods. - Under the BYOD approach, customers enroll already purchased controllable water heaters (water heaters with integrated controls) in the DLC option. - Under the DI approach, controllers are retrofitted to existing water heaters, at no-cost.
Eligible Customers	- BYOD: Residential, small commercial, and small industrial customers with electric water heaters that have integrated controllers - DI: Residential small commercial, and small industrial customers with electric water heater. Controllers are installed to existing electric water heaters, at no-cost.

²¹ Peak reduction and cost results are for the Settlement Plan.



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Item	Description
Program Enrollment Assumptions	- Steady state participation levels²² range from 10% to 30% of eligible customers depending on the customer segment and the type of delivery (BYOD and DI). - Eligible customers are those that either purchase a water heater with integrated controls or receive a direct installed controller retrofitted to an existing electric water heater. - Residential and Small C&I participation ramp - Ramps up to ~5% to 15% of steady state participation level by 2023 - Ramps up to ~25% to 40% of steady state participation level by 2025
<i>The key parameters are listed below with initial assumptions, subject to further revisions during the detailed design stage prior to launch.</i>	
Program Parameters	Operating Months - Winter peak reduction (Dec. through Feb.) - Events may be called anytime, all year round to address system emergencies and to help meet operating reserve requirements
	Event Window - Winter (5-8 pm) - Operating reserves and system emergencies (anytime and all-year round)
	Event Notification - Typically, no notification - Customers on TOU rates can choose advance notification and may receive pre-heating notification
	Event Duration: Max. 3 hours; average 2 hours Max. total event hours: 40 hours during winter (Dec. through Feb.)
	Unit Impacts - Residential: 0.5 kW/controller, 1 controller/participant; translates to 0.5 kW/participant. - Small C&I: 0.5 kW/controller, 1.08 controllers/participant; translates to 0.54 kW/participant.
Unit impacts (kW reduction per participant)	
Participation Incentives	\$5 sign-up payment per new customer enrolled in the option \$10 annual recurring payment per participant
Projected Load Reduction and Costs²³	5.5 MW projected peak load reduction in 2025 - Cumulative program costs over 2023-2025 Plan period estimated at approximately \$4.6 million

3.2.3 BNI Curtailment Option

The 2023-2025 DR Portfolio includes a BNI Curtailment option for large C&I customers from 2023 onward. The option is projected to provide around 9 MW of load reduction by 2025.

²² Represents participation levels in mature programs after an option is fully ramped up.

²³ Peak reduction and cost results are for the Settlement Plan.



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Approximately 80 percent of the total reduction is expected to be realized from large commercial customers and the remaining 20 percent from large industrial and interruptible rider customers. Table 16 presents a high-level design and outlines the key characteristics.

This option considers two delivery approaches – one approach includes an aggregator-managed option in which the program delivery is outsourced to an aggregator, while in the other approach, the option is delivered in-house. These two approaches will be equally split with 50 percent of the enrollment through the aggregator approach (referred to as the turnkey approach) and 50 percent of the enrollment through in-house delivery (referred to as the “enabling technology” approach).

Table 16. BNI Curtailment Option Characteristics

Item	Description
Program Description	E1 will offer the BNI Curtailment option to Large C&I and Interruptible customers. - Customers agree to reduce load by a fixed contracted amount when events are called; enrolled customers are paid based on contracted load reduction quantity, referred to as nominated amount (when events are not called) and actual performance (when events are called). - Load reductions are realized by controlling different types of end uses (e.g., lighting, HVAC, industrial processes, refrigeration, pumps, fans and blowers, etc.) depending on the business and facility type. - Under the aggregator-managed turnkey approach, the aggregator is responsible for delivering a contracted amount of load reduction under a pay-for-performance turnkey contract. E1 does not pay any separate enabling technology incentive (described below) under this approach. - Under the in-house delivery approach (referred to as the “enabling technology” approach), load curtailment can be manual and/or Auto-DR enabled. Under Auto-DR, customer loads will be curtailed automatically, via a building energy management control system (EMCS) or other types of end-use equipment controls in place at the facility, in response to a signal from NS Power. Auto-DR is a platform to automatically execute pre-programmed load reduction strategies in response to a signal from a Demand Response Automation Server (DRAS), without manual interventions. The customer always retains the ability to override the curtailment sequence in the event a site cannot participate in a specific demand response dispatch. Auto-DR ensures higher reliability of response than manual curtailment. Under the enabling technology approach, - E1 provides rebates for installation of advanced lighting controls through Business Energy Rebates program component of the Efficient Product Rebates program. Qualified products can be enrolled in the Auto-DR component. - E1 assists in EMCS installation for institutional and industrial participants through EMIS component of the Custom Incentives program. Qualified products can be enrolled in the Auto-DR component. - This option will primarily be offered for winter peak reduction but could also be offered year-round to provide load reductions during other months.



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Item	Description
Eligible Customers	- Interruptible Rider - Large C&I
Program Enrollment Assumptions	- Enrollment varies by customer segment (business type) and ranges from 5% to 50% of total eligible customers/load. These percentages represent steady state participation levels after the option matures. - Enrollment ramps up to 90% of steady state participation levels by the final Plan year in 2025.
Program Parameters	<i>The key parameters are listed below with initial assumptions, subject to further revisions during the detailed design stage prior to launch.</i> E1 could consider a flexible design with choices to customers on key parameters such as event notification and total maximum event hours for which customers are willing to be curtailed so as to better meet customer needs and make the option attractive to customers. Operating Months - E1 plans to utilize this for winter peak reduction (Dec. through Feb.) - Events may be called anytime, all year round to address system emergencies and to help meet operating reserve requirements. Event Window - Winter (5-8 pm) - Operating reserves and system emergencies (anytime and all-year round) Event Notification - Typically, day-ahead notification - Customers may be offered advanced notification choices (day-ahead; 2 to 4-hr. day-of; 30 minutes or 10 minutes for operating reserves), depending on need Event Duration: Max. 3 hours; average 2 hours Max. total event hours: 40 hours during winter (Dec. through Feb.)
Unit impacts (reduction per participant)	- Large C&I and Interruptible Rider unit impact: 5 to 50% of end-use load, depending on combination of type of end use and enabling technology. - Unit impacts for the Interruptible Rider class have been derated by 50% because there may be challenges in these customers participating in both the Interruptible Rider and BNI Curtailment.
Participation Incentives	\$88/kW-year based on either nominated/performed load reduction.
Projected Load Reductions and Program Costs²⁴	9 MW projected peak load reduction in 2025 - Cumulative E1 program costs for the 2023-2025 Plan period estimated at approximately \$3.3 million

²⁴ Peak reduction and cost results are for the Settlement Plan.



3.2.4 Critical Peak Pricing (CPP) Option

The 2023-2025 DR Portfolio includes a Critical Peak Pricing offer to Residential and Small C&I customers.²⁵ Customers enrolled in the CPP rate will be offered smart thermostats as an enabling technology to provide enhanced response to the rate. Participants receive direct installation of smart thermostats, at no-cost, through E1's EE programs and consequently E1 can claim only the portion of the CPP savings that is associated with the smart thermostats. The CPP savings associated with the smart thermostat portion only is projected at 0.03 MW by 2025. Approximately half of the total estimated reduction from CPP is expected to be realized from residential customers and the remaining portion from small commercial and small industrial. Table 17 presents a high-level design and outlines the key characteristics.

Table 17. Critical Peak Pricing Option Characteristics

Item	Description
Program Description	- NS Power plans to offer voluntary opt-in to Residential and Small C&I customer classes starting in 2023, based on the approved CPP rate submitted under "19479 NS Power Time Varying Pricing Project Submission", with a 150 cents/kWh critical peak rate. - Under the enabling technology component of the CPP rate, participants enrolled in the CPP rate will receive no-cost direct installed smart thermostats for customers to provide greater load reductions when CPP events are called than what customers could otherwise provide without the enabling technology. - For residential customers enrolled in the CPP rate, smart thermostats are direct installed, at no-cost, through the Efficient Product Installation component of the Existing Residential program. - For small C&I customers enrolled in the CPP rate, smart thermostats are direct installed, at no-cost, through the Small Business Energy Solutions component of the Direct Installation program.
Eligible customers	- All residential customers - Small commercial, small industrial Customers who are not enrolled in the DLC option are eligible to enroll in the CPP rate. Customers cannot dually enroll in both DLC and CPP.
Program Enrollment assumptions	15% of eligible customers (represents steady state participation levels after the option matures over a 5-year timeframe (2023-2027)).

²⁵ The CPP rate is currently only approved as a pilot. NS Power plans to continue beyond the pilot but that is contingent on pilot results and future NSUARB approval.



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Item	Description
	<i>The key parameters are listed below with initial assumptions, subject to further revisions during the detailed design stage prior to launch.</i> Operating Months - E1 plans to utilize this for winter peak reduction (Dec. through Feb.) Event Window 5-8 pm Event Notification Day-ahead and/or day-of (one to two hours in advance of the event) Event Duration: 4 to 8 hours, depending on need Max. event hours: Likely 40 hours during winter
Critical Peak Event Parameters	
Unit impacts (average load reduction per enrolled participant)	- For Residential: 10% reduction without enabling technology; 19% reduction with enabling technology. - For small C&I customers: 7.5% reduction without enabling technology; 14% reduction with enabling technology.
Projected Load Reduction and Costs²⁶	0.03 MW projected peak reduction in 2025 (portion of savings attributable to smart thermostats only)²⁷; - Cumulative program costs over 2023-2025 estimated at approximately \$156k

²⁶ Peak reduction and cost results are for the Settlement Plan.

²⁷ Note that the total estimated peak reduction from CPP in 2025 estimated at 2.2 MW, which is from the rate and the enabling technology.



3.2.5 Electric Vehicle (EV) Charging Control

The 2023-2025 DR Portfolio includes an Electric Vehicle Charging Control option for customers with EVs. The option is projected to provide approximately 0.08 MW of load reduction by 2025. Table 18 presents a high-level design and outlines the key characteristics.

Table 18. EV Charging Control Option Characteristics

Item	EV Charging Control
Description	This option will manage EV charging by controlling either through the EVSE or through onboard telematics at the vehicle. This option could potentially be integrated under a single BYOD option platform that controls multiple devices such as smart thermostats, water heaters and EVs/EVSEs.
Eligible Customers	All residential customers with qualified EV/EVSE that can be supported by NS Power's Distributed Energy Resource Management System (DERMS) or similar aggregator platform.
Enrollment Assumptions	20% steady state participation level (as % of eligible vehicles) - Ramps up to 60% of steady state participation level by 2025
Event Parameters	<i>The key parameters are listed below with initial assumptions, subject to further revisions during the detailed design stage prior to launch.</i> Operating Months - E1 plans to utilize this for winter peak reduction (Dec. through Feb.) Event Window 5-8 pm Event Notification - Day-ahead and/or day-of (one to two hours in advance of the event) Event Duration: 4 to 8 hours, depending on need Max. event hours: Likely 40 hours during winter
Unit Impacts	99% reduction in charging load coincident peak demand
Participation Incentives	\$32/kW-yr. for charging load reduction
Projected Load Reductions and Costs²⁸	0.08 MW projected peak reduction in 2025 - Cumulative E1 costs over 2023-2025 estimated at around \$352k

²⁸ Peak reduction and cost results are for the Settlement Plan.



3.2.6 Behind-the-Meter (BTM) Battery Control

The 2023-2025 DR Portfolio includes a BTM Battery Control option to residential and C&I customers with controllable battery storage systems. This option is projected to provide around 1.75 MW of load reduction by 2025. Table 19 presents a high-level design and outlines the key characteristics.

Table 19. BTM Battery Control Option Characteristics

Item	BTM Battery Control
Description	Under this option, BTM batteries will be dispatched for supply to the grid during DR events. E1 will share 20% of the installed Battery Energy Storage System (BESS) costs to help reduce customer payback and enhance adoption. In exchange, customers agree to have the BESS available for dispatch during DR events.
Eligible Customers	All customers with qualified BTM batteries that can be supported by NS Power's DERMS, or similar aggregator platform.
Enrollment Assumptions	• 50% steady state participation level (as % of eligible BTM batteries) • Ramps up to 15% of steady state participation level by 2025
Unit Impacts	For Residential and all C&I customers: 85% of battery installed kW
Participation Incentives	• 10% upfront BESS cost sharing • \$63/kW-yr. ongoing participation incentive
Projected Load Reductions and Program Costs²⁹	• 1.75 MW projected peak reduction in 2025 • Cumulative E1 program costs over 2023-2025 are estimated at approximately \$0.95 million (includes incentives for upfront cost sharing)

²⁹ Peak reduction and cost results are for the Settlement Plan.



3.2.7 Behavioural DR

E1 expect to offer a Behavioural DR option to residential customers. This option is projected to provide approximately 1.1 MW of load reduction by 2025. Table 20 presents a high-level design and outlines the key characteristics.

Table 20. Behavioural DR Option Characteristics

Item	Behavioural DR
Description	Residential customers will be offered the BDR option on an opt-in basis. BDR does not offer any financial incentives for customers to reduce their usage, nor does it require the installation of technology at a customer's premise. Instead, it provides customers with pre/post-event communications and social comparisons specifically aimed at reducing usage on event days. The fundamental concepts of BDR are like those in the Residential Behaviour program component in EE, with the key difference being that BDR is designed to target only a few hours on days when electricity demand is high. E1 would contract with a third-party vendor to offer the option and pay the vendor an all-in delivery charge per participant.
Eligible Customers	All residential customers not enrolled in the DLC and CPP options.
Enrollment Assumptions	• 20% steady state participation level (as % of eligible customers) • Ramps up to 60% of steady state participation level by 2025
Unit Impacts	2% reduction in participant demand during events
Participation Incentives	None
Projected Load Reductions and Program Costs³⁰	• 1.1 MW projected peak reduction in 2025 • Cumulative program costs over 2023-2025 Plan period estimated at approximately \$233k

³⁰ Peak reduction and cost results are for the Settlement Plan.



4. Demand Response Program Delivery

This chapter covers the following topics related to DR program delivery:

- Assumed DR Business Functions and roles and responsibilities of E1 and NS Power
- Energy Efficiency and Demand Response integration considerations
- Performance metrics for DR

4.1 DR Business Functions and E1 and NS Power Roles and Responsibilities

This section describes the core DR-related business activities and indicates E1's assumed responsibilities and NS Power's assumed responsibilities for performing these activities. The roles and responsibilities presented here are based on E1-NS Power discussions through the E1/NS Power Joint Demand Response Working Group and supported by Guidehouse's expertise in the area. Table 21 lists these functions and indicates the assumed level of responsibility for E1 and NS Power. These roles and responsibilities are likely to vary by option type.

Table 21. DR Business Functions and Assumed Responsibilities

	Business Function	Responsible Party	
		E1	NS Power
Foundation	Define Program Parameters and Initiate DR Events	Support	Perform
	Provision of DRMS/DERMS		Perform
	Marketing, Customer Recruitment & Outreach*	Perform, Support	Perform, Support
	End-use Technology Installation and Enablement	Perform	Support
Operations	Program Administration, Data and Performance Analysis	Perform, Support	Perform, Support
	Billing and Settlement	Perform	Support
Maintenance & Optimization	EM&V	Perform	Support
	Customer Service and Satisfaction	Perform	Support
	Coordination with EE programs	Perform	

*Varies by DR option type. For example, for DLC, E1 would play an active role in marketing and customer reach, whereas for CPP it would mostly be NS Power performing these activities.

4.1.1 Responsibilities by Business Function

E1's and NS Power's responsibilities toward performing these business functions are briefly described below, differentiated by DR option type, where applicable.

Define Program Parameters and Initiate Load Control Events

NS Power is assumed to undertake the following:

- Define dispatch criteria (economic, reliability, emergency, operating reserves, non-wire alternatives (NWA), etc.)



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- Define program parameters (e.g., applicable months, event hours, minimum load curtailment amount, notification, event duration, annual limit on event hours, event frequency)
- Initiate load control events

E1 would support NS Power in this business function.

Provision of DRMS/DERMS

NS Power is piloting a DERMS which it may use to manage dispatch of DR events and collect performance data. Individual technology provider and aggregator platforms may need to integrate with the existing DERMS.

Marketing, Customer Recruitment & Outreach

The roles and responsibilities of E1 and NS Power for this function could vary by DR option. For example, for the DLC option (for both Bring your Own Device - BYOD and Direct Install – DI approaches), E1 is assumed to be primarily responsible for program marketing and customer education and outreach activities and would undertake these in conjunction with EE program delivery, where applicable.

However, for CPP, NS Power would be responsible for these activities, except for the case where E1 provides enabling technologies to customers for enhancing response to the CPP rates, or where opportunities for cross-promotion and education of CPP arise through EE programs.

For all other DR options, namely - BNI Curtailment, BTM Battery Control, EV Charging Control, and Behavioural DR, E1 would be primarily responsible for undertaking program marketing and customer education and outreach activities.

Technology/Equipment Installation and Enablement

For all DR options, E1 is assumed to be primarily responsible for enabling end-use technology installation at customer sites/premises. E1 would provide incentives for enabling end-use technologies for applicable DR sub-options (e.g., smart thermostats in Direct Install delivery approach under the DLC option, EMIS and lighting controls in BNI Curtailment Option, smart thermostats for customers enrolled in CPP, and for BTM battery installation) and would be responsible for enabling technology installation and enablement for DR. Exceptions are the BYOT/BYOD option where customers bring their own devices, and the aggregator-managed turnkey BNI Curtailment delivery approach in which the aggregator is responsible for the technology installation and enablement activities.

Program Administration, Data and Performance Analysis

E1 is assumed to be primarily responsible for administering the DR program and for undertaking data and performance analysis based on data provided by NS Power and/or third-party DR service provider. E1 would be responsible for developing program performance tracking database and for data analysis for program performance calculations. NS Power would utilize the performance data to assess whether system needs are met based on the use case for DR. For the CPP rate, E1 would support NS Power in administering the rate.



Billing and Settlement

For all DR options, E1 is assumed to be responsible for billing and settlement (customer incentive payments). NS Power would support this function by providing program performance tracking data necessary to undertake settlement calculations. The only exception is CPP, where there is no incentive payment and NS Power is responsible for administering the CPP rate to its customers.

Evaluation, Measurement and Verification (EM&V)

E1 is assumed to be responsible for sponsoring independent ex-post impact and process evaluation of the program, establish baseline development methodologies and analytical framework for conducting annual impact and process evaluations. NS Power and/or third-party DR service providers would help support this function by providing all necessary data to support the EM&V analysis. NS Power would utilize the EM&V analysis information to assess whether system needs are met based on the use case for DR.

Customer Service and Satisfaction

E1 is assumed to be responsible for assessing customer satisfaction at all major customer touchpoints and for conducting periodic customer satisfaction surveys and focus groups, where relevant.

Some responsibilities could vary by option type, depending on the type of program administration. A few such examples are provided below.

- For the BYOT delivery approach, E1 could develop customer satisfaction metrics with BYOT provider and obtain relevant customer and program performance data from BYOT provider.
- For BYOT option, the service provider is responsible for call center operations, customer complaint handling and tracking.
- For BNI Curtailment, E1 is responsible for conducting periodic reviews with customers to assess satisfaction.

Coordination with EE Activities

E1 is assumed to be responsible for all aspects of coordination and integration with EE activities, where relevant. This is further described below.

4.1.2 Integrated EE-DR Program Delivery

This section describes how existing EE programs could be utilized to offer incentives for DR enablement and participation, specifically identifies EE measures that provide both EE and DR benefits and provides a framework for how DR incentives could be combined with existing EE program incentives to increase customer attractiveness and enhance participation.

Table 22 provides a mapping of residential EE programs and program components to corresponding residential DR options and outlines an integrated EE-DR approach toward program implementation. Similarly, Table 23 provides a mapping of BNI EE programs and program components to corresponding BNI DR options and outlines an integrated EE-DR approach toward program implementation.



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Table 22. Residential EE-DR Integration Considerations

EE Program	EE Program Component	EE-DR Measure for Integration	Corresponding DR Option for Integration Considerations	Brief Description of EE-DR Integration Approach
Efficient Product Rebates	Instant Savings	Smart Thermostats for the following end-use equipment types: • Baseboards • Ductless Mini Split Heat Pumps	Direct Load Control (DLC) Option with a “Bring Your Own Thermostat” (BYOT) delivery approach	• E1 provides rebates for smart thermostat purchase through the Instant Savings program component of the Efficient Product Rebates program. • Customers purchasing these smart thermostats are offered the choice to enroll in the DLC-BYOT option, which provides additional incentives for DR participation (both upfront enrolment and ongoing participation incentive).
		Smart Water Heaters (<i>water heaters with communication to be able to respond to external signals</i>)	Direct Load Control Option with a “Bring Your Own Device” delivery approach	• E1 provides rebates for purchase of smart water heaters (water heaters that can communicate and respond to external signals) purchase through the Instant Savings program component. • Customers purchasing these smart water heaters are offered the choice to enroll in the DLC-BYOD option, which provides additional incentives for DR participation (both upfront enrolment and ongoing participation incentive).



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EE Program	EE Program Component	EE-DR Measure for Integration	Corresponding DR Option for Integration Considerations	Brief Description of EE-DR Integration Approach
Existing Residential	Efficient Product Installation (EPI)	Smart Thermostats for the following end-use equipment types: - Baseboards - Ductless Mini Split Heat Pumps	Direct Load Control Option with a “Direct Install” (DI) delivery approach	- Direct installation of smart thermostats free-of-charge through the Efficient Product Installation component of the Existing Residential program. - Customers with installed smart thermostats are offered the choice to enroll in the DLC-DI option, which provides additional incentives for DR participation (both upfront enrolment and ongoing participation incentive).
			Critical Peak Pricing (CPP) with enabling technology	- Direct installation of smart thermostats free-of-charge through the Efficient Product Installation component of the Existing Residential program. - Customers with installed smart thermostats are offered the choice to enroll in the Critical Peak Pricing option offer by Nova Scotia Power. The CPP rate offers a discounted off-peak rate when compared with the customer’s Otherwise Applicable Tariff (OAT), so customers are incented to switch from existing to CPP rate.³¹

³¹ Customers can also enroll in the rate without enabling technology such as smart thermostats.



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Table 23. BNI EE-DR Integration Considerations

EE Program	EE Program Component	EE-DR Measure for Integration	Corresponding DR Option for Integration Considerations	Brief Description of EE-DR Integration Approach
Efficient Product Rebates	Business Energy Rebates	Smart Thermostats for the following end-use equipment types: - Central Heat Pumps - Baseboards - Ductless Mini Split Heat Pumps	Direct Load Control (DLC) Option with a "Bring Your Own Thermostat" delivery approach	- E1 provides rebates for smart thermostat purchase through the Business Energy Rebates program component of the Efficient Product Rebates program. - Customers purchasing these smart thermostats are offered the choice to enroll in the DLC-BYOT option, which provides additional incentives for DR participation (both upfront enrolment and ongoing participation incentive).
		Advanced Lighting Controls	BNI Curtailment	- E1 provides rebates for installation of advanced lighting controls through Business Energy Rebates program component of the Efficient Product Rebates program. - Customers installing the advanced lighting controls are offered the choice to enroll in the BNI Curtailment option, which provides additional incentives for DR participation. For DR participation, the lighting controls need to be DR-enabled. E1 pays additional upfront incentives for Auto-DR enablement.



EfficiencyOne Demand Response Roadmap

EE Program	EE Program Component	EE-DR Measure for Integration	Corresponding DR Option for Integration Considerations	Brief Description of EE-DR Integration Approach
Direct Installation	Small Business Energy Solutions	Smart Thermostats for the following end-use equipment types: • Central Heat Pumps • Baseboards • Ductless Mini Split Heat Pumps	Direct Load Control Option with a “Direct Install” delivery approach	• Direct installation of smart thermostats free-of-charge through the Small Business Energy Solutions component of the Direct Installation program. • Customers installing these smart thermostats are offered the choice to enroll in the DLC-DI option, which provides additional incentives for DR participation (both upfront enrolment and ongoing participation incentive).
			Critical Peak Pricing (CPP) with enabling technology	• Direct installation of smart thermostats free-of-charge through the Small Business Energy Solutions component of the Direct Installation program. • Customers installing these smart thermostats are offered the choice to enroll in the Critical Peak Pricing option offer by Nova Scotia Power. The CPP rate offers a discounted off-peak rate when compared with the customer's Otherwise Applicable Tariff (OAT), so customers are incented to switch from existing to CPP rate.³²

³² Customers can also enroll in the rate without enabling technology such as smart thermostats.



EfficiencyOne Demand Response Roadmap

EE Program	EE Program Component	EE-DR Measure for Integration	Corresponding DR Option for Integration Considerations	Brief Description of EE-DR Integration Approach
Custom Incentives	Energy Management Information System (EMIS)	Energy Management Control System (EMCS)		E1 assists in EMCS installation for institutional and industrial participants through EMIS component of the Custom Incentives program.
			BNI Curtailment	Customers installing EMCS are offered the choice to enroll in the BNI Curtailment option, which provides additional incentives for DR participation. E1 pays additional upfront incentives for Auto-DR enablement with the EMCS.
			Critical Peak Pricing (CPP) with enabling technology	- E1 assists in EMCS installation for institutional and industrial participants through EMIS component of the Custom Incentives program. - Customers installing EMCS are offered the choice to enroll in the Critical Peak Pricing option offer by Nova Scotia Power. The CPP rate offers a discounted off-peak rate when compared with the customer's Otherwise Applicable Tariff (OAT), so customers are incented to switch from existing to CPP rate.³³ E1 pays additional upfront incentives for Auto-DR enablement with the EMCS.

³³ Customers can also enroll in the rate without enabling technology such as smart thermostats.

4.2 Energy Efficiency and Demand Response Integration Considerations

4.2.1 Modelling Approach to Represent EE-DR Interactions

This section discusses aspects of the DR portfolio that are integrated with the inputs and outputs of ProCESS™ modelling activities conducted for energy efficiency implementation planning, namely baseline peak adjustment, eligibility alignment, and cost-sharing. In addition, there is discussion on joint cost-effectiveness testing and integration of EE and DR programs.

To account for planned energy efficiency savings, Guidehouse subtracts the projected EE portfolio savings from the sales forecast used to develop the baseline peak forecast. This step enables a more accurate estimation of peak load reduction.

In addition, Guidehouse uses the projected adoption of smart thermostats and EMCS systems from the EE portfolio in the DR estimation as an input to constrain the eligible customers for DLC and C&I Curtailment, respectively, to only customers with the appropriate enabling technology. Customers that obtained a smart thermostat through the Instant Savings program component could enroll in the BYOT offer, while those that obtained a smart thermostat through the Efficient Product Installation program component could enroll in either the DI smart thermostat offer or CPP with enabling technology offer. Similarly, customers that obtained Energy Management Information Systems through the EE program are thus eligible for the C&I Curtailment DR offering.

Per discussions with E1, Guidehouse apportioned the incremental cost of smart thermostats across the EE and DR portfolios instead of fully burdening one program with the full cost. The incremental costs were split across the portfolios based on the ratio of total measure lifetime TRC benefits. The benefits from the EE “With Carbon” scenario was used. The section below describes approaches for representing EE-DR integration considerations in cost-effectiveness assessment.

4.2.2 Integrated EE-DR Cost-Effectiveness

The cost-effectiveness of EE technologies that can provide DR benefits can be assessed from a joint EE-DR perspective under an Integrated Demand Side Management (IDSMS) framework. Examples of technologies where such an integrated approach can be followed to assess cost-effectiveness include technologies that provide EE and DR co-benefits such as smart thermostats, Energy Management Control Systems (EMCS) and advanced lighting controls.

There are two approaches for assessing cost-effectiveness of EE-DR measures from an integrated perspective, which are described below:

Option 1 – Include full EE-DR measure costs and EE and DR benefits in TRC calculations to ensure symmetry in benefits and costs for these measures. Under this option, EE and DR cost-effectiveness assessment is conducted jointly under a single framework. This entails considering the following benefits and cost items for the EE-DR measures for cost-effectiveness screening under TRC, shown in Table 24.

Table 24. Single Cost-Effectiveness Framework Used to Assess EE-DR Cost-Effectiveness

Benefits	Costs
1. Energy efficiency benefits from EE-DR measures	1. Full EE-DR measure costs (e.g., cost of a smart thermostat) plus EE program admin. and O&M costs
2. Add DR benefits for all EE-DR measures	2. Increase in program administrative costs for EE-DR measures to account for full costs of an integrated EE-DR (IDSM) program <i>Similar to EE incentives, DR incentives are assumed to be transfer payments from the utility to the customer and are not included in TRC.</i>

Option 2 – Split EE-DR measure cost in TRC calculations in EE and DR potential study/portfolio uses the split costs to assess cost-effectiveness separately under EE and DR. This entails considering the following benefits and cost items for the EE-DR measures for cost-effectiveness screening under TRC, shown in Table 25.

Table 25. Separate Cost-Effectiveness Assessment for EE-DR Measures with Split in Costs

Benefits	Costs
1. Energy efficiency benefits only from EE-DR measures in the EE potential/scenario cost-effectiveness assessment framework.	1. Develop a fraction to discount the full cost of the EE-DR measure to account for the portion attributable to EE and DR separately.
2. DR benefits only from EE-DR measures in the EE potential/scenario cost-effectiveness assessment framework.	The split in costs is based on the ratio of Net Present Value (NPV) of EE and DR benefits over the lifetime of the measure.

The two options differ in their approaches in how symmetry in benefits and costs are incorporated for cost-effectiveness tests but are expected to lead to the same conclusion in terms of cost-effectiveness of measures. The pros and cons associated with the two options are presented in Table 26.

Table 26. Pros and Cons of EE-DR Cost-Effectiveness Options

Approach for benefits and costs symmetry	Pros	Cons
Option 1	Including both EE and DR benefits ensure alignment with the programmatic/policy goals toward IDSM (integrated EE-DR). It could help foster integration at the EE and DR program levels to allow for a wider range of EE-DR measures to be included in programs.	- Setting of EE goals based on selected measures from the joint EE-DR cost-effectiveness screening require policy agreement on how integrated EE and DR options are viewed and cost-effectiveness is treated. - Basis for assumptions for increase in program administration and O&M costs for IDSM programs need to be developed, which may be difficult to estimate.
Option 2	Easier to implement since policy implications could be lower if one were to use discounting of costs instead of considering integrated benefits, even though it would still necessitate agreement on the approach for discounting costs.	Does not consider EE-DR measures holistically within an IDSM programmatic framework with joint cost-effectiveness screening of measures.

In light of the above, Guidehouse, in discussions with E1, decided to follow option 2 for assessing cost-effectiveness of measures that provide both EE and DR benefits. As outlined above, Guidehouse used the ratio of NPV of EE and DR benefits over the measure lifetime to split measure costs for EE and DR.

A few jurisdictions, such as California, Massachusetts, and Michigan in the U.S. have been interested in the joint EE-DR cost-effectiveness framework. California has been leading EE-DR integration considerations and recently incorporated joint EE-DR cost-effectiveness testing as part of the statewide EE potential study.³⁴ It was considered as part of the EE-DR integration scenario analysis in the potential study and was not included as part of the core analysis for determination of the EE goals for California utilities. EE-DR integrated cost-effectiveness was considered from a theoretical perspective since no IDSM cost-effectiveness protocols or policy guidelines for technologies that can provide dual EE-DR benefits exists in the state. Consequently, absent policy directives, developing an IDSM framework for joint EE and DR cost-effectiveness remains a challenge in California. Historically, the cost-effectiveness frameworks for EE and DR were developed in different proceedings over the course of many years, and they each have different cost-effectiveness reporting tools. Additionally, the

³⁴ <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/energy-efficiency-potential-and-goals-studies/2021-potential-and-goals-study>

estimation techniques used to determine the cost and benefit inputs for EE and DR differ. These factors hinder an integrated EE-DR cost-effectiveness approach.

Table 27 summarizes the benefits and costs for EE-DR technologies used in the cost-effectiveness calculations under the total resource cost (TRC) test as part of the EE potential study in California. Under the program administrator cost (PAC) test, both EE and DR incentives need to be included under costs. For DR, the incentive costs include upfront DR program enrollment incentives and ongoing DR participation incentives. The California study found that integrated EE-DR cost-effectiveness assessment resulted in higher B/C ratios of EE-DR measures and led to certain measures that were not cost-effective on EE basis only being cost-effective.

Table 27. California Benefits and Costs from EE-DR Measures in the Cost-Effectiveness Calculations (based on TRC)³⁵

Benefits	Costs
• Avoided energy and demand costs from EE • Avoided capacity, energy, and greenhouse gas (GHG) emissions costs for DR	• Full EE-DR measure costs (e.g., cost of a smart thermostat) • EE incentives for free riders³⁶ • EE administration costs • DR program administration costs • EE operations and maintenance (O&M) costs • DR O&M costs

Source: Guidehouse

A similar integrated EE-DR cost-effectiveness framework was followed in assessing cost-effectiveness of EE-DR measures in the statewide EE and DR potential studies for Michigan.³⁷ However, similar to California, cost-effectiveness tools and policy guidelines for treating EE and DR cost-effectiveness are different, and therefore it may take some time for utilities in Michigan to adopt an integrated cost-effectiveness framework as part of their EE and DR program plans. In Massachusetts, Program administrators administering EE and DR programs have expressed interest in EE-DR integration in cost-effectiveness assessment, and plan to undertake additional research to explore this area further.

Therefore, based on pros and cons of the two options presented above for EE-DR integration for cost-effectiveness and what other jurisdictions have been considering, Guidehouse recommends that E1 should follow “Option 2” with cost sharing between EE and DR measures until an integrated framework is adopted.

³⁵ This is included in the California Statewide Potential and Goals study under the EE-DR integration discussion. The study is available at <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/energy-efficiency-potential-and-goals-studies/2021-potential-and-goals-study>

³⁶ DR does not have any free riders, so free rider incentives do not apply to DR.

³⁷ EE Potential study available at https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Report_-_Final_735360_7.pdf

DR Potential Study available at: https://www.michigan.gov/documents/mpsc/MI_DR_Statewide_Potential_Study_Report_-_Final_736593_7.pdf

Filed Electronically

Appendix A

Attachment 6: 2023-2025 Demand Response Technical Tables

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Appendix B

Rate and Bill Impact Analysis of the 2023-2025 DSM Plan

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1. EXECUTIVE SUMMARY

EfficiencyOne (E1) delivers energy efficiency (EE) programs that offer benefits to customers and the electric utility. While cost-effective energy efficiency is a key resource option for delivering clean, affordable, reliable and safe energy services to Nova Scotian customers, concerns about possible rate impacts often represent a significant barrier to expanding investments in energy efficiency.

It is generally understood that demand side management (DSM) programs typically result in reductions in customer bills that more than offset any increase in rates, if they do occur. These rate and bill effects impact customers in different ways. Those customers that participate in DSM programs may experience higher rates but lower bills, while those customers that do not participate in DSM programs may only experience the higher rates. Thus, rate and bill impact concerns are effectively an issue of customer equity. Understanding the degree to which rates may increase over the long-term, together with the expected bill reductions and the level of participation in energy efficiency programs can help inform how ratepayers fare overall from investments in DSM.

E1's Rate and Bill Impact Analysis (RBIA) provides insight on the questions above through an assessment of the rate and bill impacts of DSM in Nova Scotia. E1's 2023-2025 DSM Resource Plan Rate and Bill Impact Analysis, provides a broad trend-based picture of the rate and bill impacts of proposed DSM activities to be carried out during the 2023-2025 period, looking forward until 2039, when the modelled impacts of 2025 measures expire. These results offer a frame of reference for considering the appropriate balance of these impacts across electricity customers.

Two DSM plans have been modelled within this analysis – E1's Settlement 2023-2025 DSM Resource Plan (Settlement Plan) and its Alternate Scenario – each with different levels of DSM investment and savings. For each of these plans, the differences between two scenarios are compared – a no-DSM scenario that does not include 2023-2025 DSM impacts, and a DSM scenario that allocates program investments, avoided costs, and recovery of lost revenues arising from 2023-2025 DSM activities to each participating rate class, excluding Unmetered. It is important to note that the RBIA examines DSM effects in isolation of utility effects, such as timing of infrastructure upgrades or general rate applications. As such, it provides insight into the average pressure of the proposed DSM Plan investment on rates and bills and is not intended to estimate the actual rates or bills experienced by customers in a particular rate class or year. The RBIA is intended to provide insight into average long-term trends of rate and bill impacts on rate classes, comparing

a scenario with DSM and a counter-factual scenario of no-DSM. Key outputs of the analysis are how much more non-participants will pay due to DSM (non-participant bill impacts), and how many non-participants there are. Cost effectiveness testing of DSM Plans demonstrates whether the investment is beneficial for customers as a whole; while the RBIA looks more closely at the worst-case scenario (a non-participant in each rate class) to see how much higher their bills are due to DSM. This information is critical in addressing issues of DSM affordability.

From the time E1 filed its forward looking RBIA for the 2020-2022 DSM Resource Plan on 28 February 2019 a significant level of stakeholder engagement was undertaken through a RBIA Technical Session with the Demand Side Management Advisory Group (DSMAG), written stakeholder submissions, and subsequent stakeholder discussions. As a result, several revisions were made for the 2020 Historical RBIA, the most significant of which was the removal of all cost allocation functionality. Effective with the 2020 RBIA, this work is now performed by Nova Scotia Power (NS Power) to align with their Cost-of-Service Study (COSS) more closely, such that rate impacts presented in the RBIA more accurately reflect NS Power's cost recovery across all rate classes. The general perspective remains the same – rate impacts are measured relative to a scenario with no DSM at all; they are not incremental impacts relative to 2022 rates. Following the filing of the 2020 Historical RBIA in December 2020, stakeholder engagement was undertaken through meetings and email correspondence to discuss the remaining items raised by stakeholders in the 2020 Historical RBIA proceeding. The most significant change made to E1's subsequent RBIA, in 2021, was the use of updated avoided costs from the 2020 Integrated Resource Plan (IRP). The new avoided costs of energy and avoided costs of capacity, used for the 2021 RBIA (2023-2040), were 30 percent lower, and 41 percent lower, respectively, compared to the avoided costs from the 2014 IRP, used for the 2020 RBIA. In addition, NS Power also made improvements to the NS Power Rate Model by incorporating transfer tables and cost allocation summary tables.

Since the filing of E1's 2021 RBIA on 1 November 2021, the most significant changes made in the 2023-2025 DSM Plan RBIA are the:

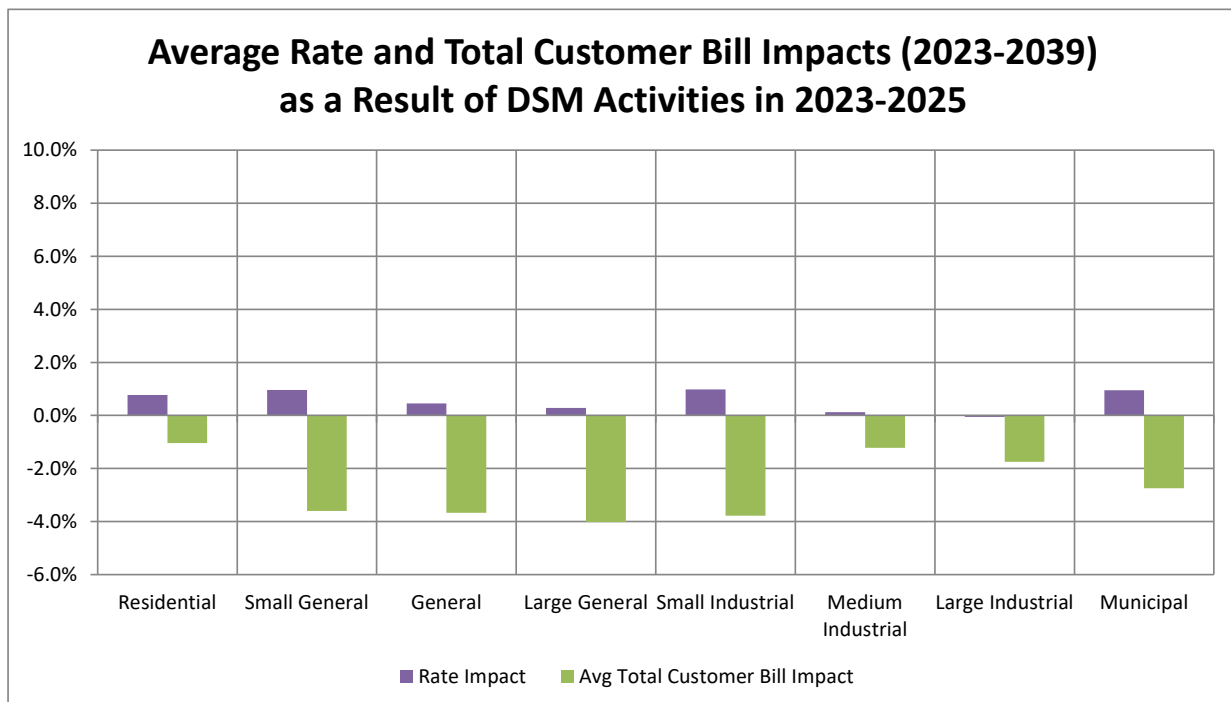
- use of avoided costs of carbon for the first time in DSM planning;
- incorporation of demand response (DR) program components into the E1 RBIA and NS Power cost of service models; and
- addition of partial year measure lives in the E1 and NS Power model.

Key highlights of the 2023-2025 Settlement Plan RBIA¹ include:

- Over the 17-year study period, participants in DSM programs see average annual bill reductions ranging from a low of 1.2 percent (typical Medium Industrial participant) to a high of 7.9 percent (typical Small General participant).
- Over the 17-year study period, the average bill impacts to non-participants (by rate class) range from -0.1 to +1.0 percent.
- Over the 17-year study period, the average upward rate pressure of DSM varies from a low of -0.1 to a high of +1.0 percent across all rate classes.
- Nova Scotian ratepayers will save \$0.4 billion² as a result of energy and demand reductions achieved by 2023-2025 DSM programs.
- Maximizing customer participation in DSM programs mitigates rate impacts by increasing the number of customers who experience net bill reductions.

Average rate and bill impacts of DSM for total ratepayers are shown below in Figure 1.

Figure 1: Average Rate and Bill Impacts (2023-2039) as a Result of DSM Activities in 2023-2025 (Settlement Plan)



¹ Includes both energy efficiency and demand response activities

² \$376.9M net benefits (EE) + (-\$8.2M) net benefits (DR) = \$368.8M total net benefits

2. INTRODUCTION

E1 files an historical RBIA to provide insight into the rate and bill impacts resulting from DSM activities that have been carried out since 2011, as well as those that have been approved by the Nova Scotia Utility and Review Board (NSUARB) for future years (2020-2022). E1's most recent historical RBIA was filed on 1 November 2021. Differences between the two scenarios are compared – a counterfactual no-DSM scenario that does not include impacts from 2011-2022 DSM programs, and a DSM scenario that includes program investments, avoided costs, and recovery of lost revenues arising from 2011-2022 DSM activities for each major participating rate class. The analysis examines DSM effects in isolation of utility effects such as the specific timing of infrastructure upgrades or general rate applications, or the creation of rate stability periods. As such, it provides insight into the average pressure of DSM on rates and bills over the long term, as opposed to forecasting NS Power rates with a high degree of specificity in any given year.

E1 also files a RBIA impact analysis with its DSM Resource Plan Applications. In this case, the RBIA is an analysis of the rate and bill impacts associated with the proposed DSM investment only. The forward-looking rate and bill impact analysis associated with a DSM Plan Application compares the impacts of the proposed DSM investment to a scenario where there is no DSM investment during the DSM Plan period. It does not assess the rate pressure of the incremental investment amount proposed in the DSM Plan compared to what is currently being collected by ratepayers for DSM. E1, the NSUARB, and other stakeholders use this forward-looking RBIA to inform their consideration of the proposed DSM Resource Plan investment levels; in particular, it augments cost effectiveness test results by estimating the effects of DSM on non-participants.

The analysis provides the reader with a picture of these impacts for the following groups of ratepayers (excluding Unmetered) in total, and by rate class:

- Non-participants – those ratepayers that do not participate in DSM program activities;
- Participants – those ratepayers that do participate in DSM program activities and achieve statistically 'average' savings; and
- Total Customers – a perspective that does not consider participation and allocates DSM savings equally among all class members.

1 The current analysis estimates annual impacts from 2023 to 2039, when the impacts of measures installed
2 in 2023 expire. The forward-looking analysis has been performed for both E1's 2023-2025 Settlement Plan
3 and Alternate Scenario.

4
5 Both the historical and forward-looking RBIA analysis allow stakeholders to obtain an understanding of how
6 DSM investment may impact participating and non-participating ratepayers. Broadly speaking, this is
7 primarily a question of customer equity, given that participants see lower bills, while non-participants
8 experience higher bills (however, in some rate classes, it is likely that all customers participate each year).
9 The results of the historical RBIA can be used by stakeholders as one frame of reference to qualitatively
10 assess any trade-offs between investment in cost-effective DSM and rate impacts. According to the
11 National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, "*there*
12 *is no bright line to determine how to balance these different impacts. Instead, this balance will need to be*
13 *drawn by efficiency planners, ultimately with guidance and final approval of regulators.*"³

14
15 The original RBIA model, filed on 14 November 2013, along with a detailed methodology report, was
16 designed to show the average, long-term effect of DSM on rates and bills. The model was developed by
17 Efficiency Nova Scotia Corporation and Elenchus Research Associates (Elenchus) and built on a sample
18 framework provided by the NSUARB's consultant on this Matter, Synapse Energy Economics (Synapse).
19 Prior to the 2013 filing, it was reviewed several times by Synapse and subsequently revised to ensure it
20 served its required purposes. It has been further revised several times since then, based on feedback from
21 past filings and discussions with the DSMAG. The model includes enhancements made to the version used
22 for the 2021 RBIA, which are described in Section 3.

23
24 Section 4 provides an overview of the model framework and discusses key assumptions. Results are
25 discussed in Section 5, with overall trends followed by individual rate class impacts. Section 6 compares the
26 RBIA results between the Settlement Plan and Alternate Scenario. Section 7 provides an outlook on future
27 work that will influence the next application of the RIBA. Concluding remarks are made in Section 8.

28
29 Attachment 1 provides a Summary of Results (Filed Electronically) for both the Settlement Plan and
30 Alternate Scenario. Attachments 2 and 3 provide outputs from the model for each rate class analyzed for

³ National Efficiency Screening Project (NESP), National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, May 18, 2017, page 126.

1 the Settlement Plan and Alternate Scenario, respectively. A list of assumptions, and their derivations, are
2 included as Attachment 4. Attachment 5 has been provided by NS Power and details the methodology they
3 used to generate the cost allocation inputs used in E1's RBIA model for the 2021 Historical RBIA, which
4 remains consistent for the 2023-2025 DSM Plan RBIA. Both versions of NS Power's Rate Model (Filed
5 Electronically) have been included as Attachments 6 and 7. Both versions of E1's RBIA Model (Filed
6 Electronically) have been included in the electronic version of this filing as Attachments 8 and 9.

3. UPDATE ON MODEL EVOLUTION

E1 filed its 2021 RBIA Report with the NSUARB on 1 November 2021. In response to requests by Synapse and Resource Insights (RI), to increase transparency in the NS Power rate analysis, NS Power incorporated the following into the 2021 NS Power Rate Model:

- Transfer tables ('Transfer Function & Cost Factor' tab); and
- Cost allocation summary table ('Summary' tab).

The 2021 RBIA also incorporated the updated avoided costs of energy and capacity from the 2020 IRP Reference Plan.

3.1 UPDATES IN THE RBIA FOR THE 2023-2025 DSM PLAN

3.1.1 MODEL EVOLUTION

The 2023-2025 DSM Plan includes a demand response (DR) program for the first time. In response to this new program, E1 worked with its RBIA consultant Elenchus to integrate DR into the E1 RBIA model and NS Power Rate Model. Based on these changes the model can now provide results of total DSM (energy efficiency plus demand response), only energy efficiency, or only demand response. For the purposes of this report, total DSM results are presented.

E1 also worked with Elenchus to modify measure life treatment within the E1 RBIA model and NS Power Rate Model. Prior to the 2023-2025 DSM Plan model rate class measure lives were truncated to the nearest whole number in the model. For example, if the 2020 residential rate class weighted average measure life was 10.5 years, 10 years would be used in the model. This resulted in measures lives being consistently conservative in the model and the exclusion of some DSM impacts near the end of the study period. This also meant that random variation in how much of a partial year remainder was truncated could impact the results, particularly when comparing DSM Plans that may otherwise be relatively similar. For instance, if one plan had a weighted average measure life of 10.1 years and another 9.9 years, in the model these would become 10 years and 9 years respectively, which would disadvantage the second plan compared to the first by a full year of savings, despite the actual difference being only one fifth of a year.

Based on these observations, Elenchus recommended a more precise methodology whereby the measure life fraction would be included in the model. For example, if a rate class had a weighted average measure

life of 10.5 years the model would include 50% of the savings in the 11th year. This change was made in both E1 and NS Power's models.

3.1.2 AVOIDED COSTS

The RBIA for the 2023-2025 DSM Plan used the following avoided costs. All values are nominal.

ENERGY: Updated avoided costs of energy from the recent NS Power 2020 IRP. Specifically, the Actual Annual avoided costs of energy as calculated by NS Power for the IRP Reference Plan (scenario 2.0C) and provided to the DSMAG on August 20, 2021. These values are provided in Table 1, below.

Table 1: Actual Annual Avoided Cost of Energy Values used for This Analysis

Year	Actual Annual Escalating Series – AVC – Energy (\$/MWh)
2023	\$92
2024	\$65
2025	\$77
2026	\$83
2027	\$85
2028	\$76
2029	\$76
2030	\$89
2031	\$85
2032	\$85
2033	\$85
2034	\$84
2035	\$85
2036	\$91
2037	\$94
2038	\$91
2039	\$88
2040	\$87

CAPACITY: Updated avoided costs of capacity from the recent NS Power 2020 IRP. Specifically, E1 used the Fitted Series Planning Reserve Margin (PRM) adjusted stream of avoided costs of capacity, as calculated by NS Power for the IRP Reference Plan (Scenario 2.0C) and provided to the DSMAG on 20 August 2021 for the E1 RBIA. These values are provided in Table 2, below.

Table 2: PRM Adjusted Fitted Series Avoided Cost of Capacity Values Used for This Analysis

Year	PRM Adjusted Fitted Series – AVC – Capacity (\$/kW-year)
2023	\$26
2024	\$40
2025	\$54
2026	\$67
2027	\$80
2028	\$91
2029	\$102
2030	\$112
2031	\$122
2032	\$130
2033	\$138
2034	\$145
2035	\$152
2036	\$157
2037	\$162
2038	\$167
2039	\$170
2040	\$173

TRANSMISSION & DISTRIBUTION (T&D): System-wide avoided costs of T&D as calculated by NS Power and distributed to the DSMAG on 22 May 2021. The calculated values are presented as a snapshot in time for the year 2021. For the 2023-2025 DSM Plan RBIA, E1 applied a 2 percent inflation rate to this starting point to produce a stream of annual values. These values are presented in Table 3, below.

1

Table 3: Avoided T&D Cost Values Used for This Analysis

Avoided T&D Costs – System Wide			
Year	Transmission (\$/kW-year)	Distribution (\$/kW-year)	Total (\$/kW-year)
2021	\$23.20	\$20.20	\$43.40
2022	\$23.66	\$20.60	\$44.27
2023	\$24.14	\$21.02	\$45.15
2024	\$24.62	\$21.44	\$46.06
2025	\$25.11	\$21.87	\$46.98
2026	\$25.61	\$22.30	\$47.92
2027	\$26.13	\$22.75	\$48.88
2028	\$26.65	\$23.20	\$49.85
2029	\$27.18	\$23.67	\$50.85
2030	\$27.73	\$24.14	\$51.87
2031	\$28.28	\$24.62	\$52.90
2032	\$28.85	\$25.12	\$53.96
2033	\$29.42	\$25.62	\$55.04
2034	\$30.01	\$26.13	\$56.14
2035	\$30.61	\$26.65	\$57.27
2036	\$31.22	\$27.19	\$58.41
2037	\$31.85	\$27.73	\$59.58
2038	\$32.49	\$28.28	\$60.77
2039	\$33.14	\$28.85	\$61.99
2040	\$33.80	\$29.43	\$63.23

2

3 CARBON: Avoided costs of carbon are being incorporated for the first time in DSM planning in the 2023-
4 2025 DSM Resource Plan, per direction from the NSUARB. E1 used the Federal Carbon Pollution Pricing
5 Benchmark⁴ as provided in Table 4, below.

⁴ <https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html>

Table 4: Federal Carbon Pollution Pricing Benchmark Values Used for This Analysis

Year	Federal Carbon Pollution Pricing Benchmark (\$/tonne)
2020	\$30
2021	\$40
2022	\$50
2023	\$65
2024	\$80
2025	\$95
2026	\$110
2027	\$125
2028	\$140
2029	\$155
2030	\$170
2031-2040	Extrapolated using 2% annual inflation

The carbon prices outlined in Table 4, above, were applied to the estimated avoided carbon emissions from DSM, determined using the Difference in Carbon Emissions (DICE) methodology, to determine the avoided costs of carbon. The DICE method is similar to the treatment of avoided costs of energy. The amount of carbon reduction due to DSM was calculated by comparing the IRP carbon emissions between scenarios with, and without, DSM that are otherwise the same. A savings-intensity was then developed in order to model levels of DSM that differ from what was modeled in the IRP. The avoided cost of carbon has been calculated by multiplying the Federal Carbon Pollution Pricing Benchmark by the emissions intensity, determined using the DICE method. This resulted in an avoided cost of carbon per MWh saved by DSM, which are based on a comparison between the IRP Scenario 2.0C with Base-DSM, and with No-DSM, shown in Table 5, below. More detail on the DICE methodology is provided in Attachment 2 to Appendix A.

Table 5: Carbon Savings Intensity Used for This Analysis

Year	Carbon Savings Intensity (t/MWh)
2021	0.693
2022	0.930
2023	0.861

Year	Carbon Savings Intensity (t/MWh)
2024	0.898
2025	0.632
2026	0.448
2027	0.355
2028	0.431
2029	0.393
2030	0.086
2031	0.159
2032	0.320
2033	0.360
2034	0.369
2035	0.269
2036	0.355
2037	0.288
2038	0.239
2039	0.218
2040	0.221

1

2 The full range of avoided cost values used in this analysis are presented in Table 6.

3

4 Table 6: Full Range of Avoided Cost Values Used for This Analysis

Category	Years	Details
Capacity (\$/kW-year)	2023-2040	Fitted series PRM adjusted stream (AVC 2.0C NPV 2023) of avoided costs of capacity, as calculated by NS Power for the IRP Reference Plan (Scenario 2.0C) and provided to the DSMAG on 20 August 2021.
Transmission (\$/kW-year)	2023-2040	23.2 \$/kW-year in 2021 - System-wide avoided costs of transmission as calculated by NS Power for 2021. 2% inflation applied for all other years to produce a stream of annual values.
Distribution (\$/kW-year)	2023-2040	20.2 \$/kW-year in 2021 - System-wide avoided costs of distribution as calculated by NS Power for 2021. 2% inflation applied for all other years to produce a stream of annual values.
Energy (\$/MWh)	2023-2040	Actual annual AVC energy stream (AVC 2.0C NPV 2023) of avoided costs of energy, as calculated by NS Power for the IRP Reference Plan (Scenario 2.0C) and provided to the DSMAG on 20 August 2021.

Category	Years	Details
Carbon (\$/MWh)	2023-2040	• Based on the Federal trajectory of the cost of carbon, starting at \$30 per tonne in 2020, and escalating to \$170/tonne in 2030, and escalating by 2% annual inflation beyond 2030. • The price of carbon (\$/tonne) is multiplied by NS Power's emissions intensity for Base DSM savings (tonne/MWh), established using the Difference in Carbon Emissions (DICE) method for the IRP Reference Plan (Scenario 2.0C), to result in a \$/MWh avoided cost of carbon.

4. METHODOLOGY AND ASSUMPTIONS

This section describes the overall modelling and key assumptions.

4.1 SETTLEMENT PLAN AND ALTERNATE SCENARIO

The 2023-2025 DSM Plan includes both a Settlement Plan and an Alternate Scenario, which contain different investment levels and savings over the three years of DSM delivery. A RBIA was performed for both, using separate Excel models, both of which have been filed electronically. The model for both Plans is identical; the only differences are the DSM costs, savings, and participation estimates for the 2023-2025 period.

4.2 SCENARIOS

E1's RBIA models both compare two scenarios: a DSM scenario and a no-DSM scenario. The DSM scenario includes the estimated utility costs and resulting energy and system-peak demand reductions of DSM programs that are proposed to operate in 2023 through 2025 (which are different for the Settlement Plan and Alternate Scenario). The no-DSM scenario excludes DSM costs and benefits resulting from DSM in 2023 through 2025.

The rate and bill impacts calculated in each of E1's RBIA models are differences in rates and bills between the DSM and no-DSM scenarios for the same year, thereby isolating the effects of 2023-2025 DSM. For example, a calculated one-percent rate impact in 2025 indicates that the variance between 2025 rates in the DSM scenario, as compared to the no-DSM scenario, is one percent, all else being equal; not that the rate increase from 2024 to 2025 in the DSM scenario is one percent. A one-percent rate impact in all years would indicate that rates increased by one percent in the first year of DSM programming to begin recovering DSM program costs, after which no further rate changes were caused by DSM. In addition, the rate impact does not reflect actual rate timing increases that will be experienced by ratepayers.

4.3 CUSTOMER CLASSES

E1's RBIA model present results, by rate class, for the following NS Power customer classes:

- Residential (rate codes 2, 3, 4, 5, 6, 9 and 16);
- Small General (rate code 10);
- General (rate code 11);

- Large General (rate code 12);
- Small Industrial (rate code 21);
- Medium Industrial (rate code 22);
- Large Industrial (rate codes 23 and 25, and customers under the ‘one-part high voltage real time pricing’ tariff); and
- Municipal (rate code 24)⁵.

4.4 TIME PERIOD DEFINITIONS

In this analysis, the following time period definitions apply:

- DSM delivery period: the timeframe over which DSM programs are delivered. The DSM delivery period is 2023-2025.
- cost recovery period: the timeframe over which DSM program costs are recovered. Program costs for 2023-2025 are assumed to be completely recovered within each of those years. 2015 program costs recovery, which was amortized over a period of 2016-2023, has not been modelled because the objective of the DSM Plan RBIA is to isolate the impacts of 2023-2025 DSM activities.
- study period: the full timeframe over which impacts are modelled, and the period over which temporal average impacts are calculated. The study period ends once all average rate class DSM impacts have expired. The study period is 2023-2039.

4.5 PROGRAMS

Since the entire portfolio of electricity DSM programs impacts future rates and bills, the analysis includes all DSM programs that are funded by NS Power and for which costs are recovered from electricity system ratepayers.

4.6 CALCULATING RATE IMPACTS

Using the RBIA approach implemented for the first time in the 2020 RBIA, rate impacts are now calculated in NS Power’s Rate Model (Attachment 6 for the Settlement Plan and Attachment 7 for the Alternate

⁵ The number of Municipal Electric Utilities (MEUs) was updated from six to five in the 2021 RBIA as a result of the Canso Electric Light Utility dissolving and all assets and customers being transferred to NS Power as of 1 January 2020. The five MEUs are treated as the only five customers in NS Power’s Municipal rate class, and each MEU is considered to be a participant in E1 programs when any customer within their distribution system participates in a program. Participation of individual customers connected to MEU distribution systems is not modelled.

Scenario, both filed electronically) to reflect NS Power's Cost of Service in a more precise manner. NS Power's Rate Model methodology is described in Attachment 5.

E1 utilizes Forecast Unit Revenues with, and without, DSM from NS Power's Rate Model as inputs into E1's RBIA Model, to assess the bill impacts. The unit revenues, provided by NS Power's model, blend DSM energy and demand impacts into one \$/kWh rate, which E1 utilizes in its RBIA Model. E1 incorporates customer charges into the E1 RBIA as this does have a small impact on the relative rate impacts for rate classes with customer charges (Residential and Small General). NS Power's Rate Model presents rate impacts without customer charges in the tab "COSS Outputs 1," while results with customer charges added back in are presented in the tab "COSS Outputs 2."

The RBIA does not forecast the timing of general rate applications, or the occurrence of any future rate adjustments. By presenting results as differences between the DSM and no-DSM scenarios, the effects of DSM are isolated from all other utility effects that may also impact rates. Any rate effects presented here should be interpreted as the annual 'rate pressure' from DSM, in comparison to a theoretical scenario where no DSM was undertaken.

4.7 CALCULATING BILL IMPACTS

This section describes key elements of the bill impact calculations.

4.7.1 NO-DSM CONSUMPTION

In the no-DSM scenario, for each rate class, and for each year, the estimate of total class energy consumption is divided by the number of customers to produce an estimate of the average customer's consumption. This average consumption, along with no-DSM scenario rates, are used to calculate average bills for the no-DSM scenario.

4.7.2 NON-PARTICIPANT CONSUMPTION AND BILL IMPACTS

In the DSM scenario, non-participants in DSM programs are assumed to use the same amount of energy as they do in the no-DSM scenario. Their bill impacts are therefore driven only by changes in rates under the with-DSM scenario. Although non-participant bill impacts are only driven by changes in rates, the percentage bill impacts are often different than the percentage rate impacts; this is due to fixed customer charges on bills, which are unaffected by DSM.

4.7.3 PARTICIPANT CONSUMPTION AND BILL IMPACTS

For the DSM scenario, within each rate class in each year, total annual savings (i.e. current-year savings plus persistent savings from past years) are divided equally amongst the cumulative number of participants within the study period. The model does not estimate impacts for multiple ‘depths of participation,’ i.e. all participants in each class are assumed to save the same amount of energy and system-peak demand. In reality, some participants would save more, and others would save less. This average savings, along with the with DSM scenario rates, are used to calculate average bill impacts for participants.

4.7.4 TOTAL CUSTOMER CONSUMPTION AND BILL IMPACTS

The output graphs include a third category of participants, called Total Customers. Impacts for this category are determined by allocating DSM savings for the class equally among all customers in the class. This average savings, along with the DSM scenario rates, are used to calculate the average bill savings for Total Customers. It provides an estimate of bill impacts for the class without differentiating between participants and non-participants.

4.8 CALCULATING PARTICIPATION IMPACTS

This section describes the development of participation figures, which are used for the participant bill impact calculations.

For illustrative purposes, participation graphs, provided in Attachments 2 and 3, include historical/planned participation in 2011-2022 DSM programs. These participation figures are identical to those used in E1’s revised historical 2021 RBIA (filed 20 January 2022).

4.8.1 CUMULATIVE AND ANNUAL PARTICIPATION

Each year, E1 combines participant records (for programs that track participant information) with participant records from previous years. In this way, E1 can identify the first year that a customer participated in a program, so that they are counted only once, as a unique participant, and cumulative participation rates can be determined. For the presentation of annual participation figures, customers are counted once in each year they participate.

POINT-OF-SALE DISCOUNT PROGRAM COMPONENTS

E1 operates two program components that offer rebates at the point-of-sale: residential Instant Savings and the Instant Rebates portion of Business Energy Rebates (BER-IR). These program components do not collect participant information, so E1 estimates the number of customers that participate each year, and to which rate classes they belong, based on transaction records and ad-hoc primary research. E1 employs the assumption that all customers in large commercial, industrial, and municipal classes (12, 22, 23/25, 24) participate in BER-IR each year. Attachment 4 provides a full description of the methodology of these estimations.

4.8.2 PARTICIPATION FOR 2023-2025 DSM PLAN YEARS

E1 has estimated 2023-2025 annual and new participation figures based on actual participation records from 2020⁶, scaling factors to account for planned savings in 2023-2025, and changes in measure mix. The two scaling factors are:

- The ratio of program component energy savings between 2023-2025 and 2020; the application of this factor relies on the assumption that the number of participating NS Power accounts will vary in proportion with the program energy savings.
- The ratio of the number of rebated products per GWh of energy savings between 2023-2025 and 2020; the application of this factor relies on the assumption that the number of participating NS Power accounts will also vary in proportion with the number of products rebated.

Scaling factors were not applied to Affordable Multi-family Housing and Non-Profit Organizations, Affordable Single-family Homes, Home Energy Assessment, Mi'kmaw Home Energy Efficiency Project, New Home Construction, and Residential Behaviour, where number of participants were estimated directly as inputs to Guidehouse's ProCESS™ model. For Custom Incentives, the measure-mix factor was not required as the program does not contain 'measures' in the same sense as other programs within the Guidehouse model, and so differences in the measure mix for Custom Incentives between 2020 actuals and 2023-2025 could not be quantified.

By scaling 2020 participation by planned 2023-2025 energy savings, coronavirus disease (COVID-19) energy impacts are accounted for, and do not skew 2023-2025 estimated participation numbers. For example, if a

⁶ The most recent year with participant records at the time of the 2021 Historical RBIA development.

program had 1,000 participants and achieved 1 GWh of savings in 2020, and is planned to achieve 2 GWh in 2023, then the participation for that program would be scaled by a factor of 2 to 2,000 participants.

In order to properly calculate participant bill savings resulting from the Plan, it was necessary to also estimate the number of cumulative participants (i.e. unique NS Power accounts) *within the three-year DSM delivery period*. The number of annual participants in the first year of the Plan are all considered 'new' in this context. Estimates were then developed for the number of participants in each of the second and third years of the Plan that would not have already participated within this three-year period. The model already contains estimates of new participants in these years; however, these new participants are incremental to all past years, starting in 2011.

In order to estimate new participants relative to 2023, the ratio of new to annual participants in 2011-2013 was calculated for each class, which approximates an exponential decay curve, and accounts for the fact that delivering the same programs for the same customer base over several years will result in fewer new, unique NS Power accounts that participate, even if annual participation rates remain the same. It was assumed that, within each class, the decay rate of new participants over 2023-2025 would reflect that which occurred over 2011-2013, and so the ratio of new to annual participants in the 2011-2013 period was applied to 2023-2025 annual participants. A cumulative sum of these figures within each class, starting in 2023, is considered the number of cumulative DSM participants within the three years of the Plan. Total annual energy and system-peak demand savings in each year are divided by these participation figures to determine the average DSM participant consumption, which is used to calculate participant bill savings. The calculation of rates and, therefore, non-participant bills is not affected by these participation estimates.

Participation for Demand Response is estimated based on Guidehouse's DRSim™ model results. For total DSM results, the RBIA model uses the greater of either the energy efficiency rate class participation or demand response rate class participation. This is a reasonable assumption given E1 does not currently have any data on what the overlap between energy efficiency and demand response participation will be.

4.9 DEMAND RESPONSE

This section discusses how demand response has been incorporated into the E1 RBIA model and NS Power Rate Model.

Demand Response costs, savings, measure life, and customer incentives are first calculated and provided separately in the model from energy efficiency inputs. Demand response inputs are determined separately from energy efficiency to allow multiple scenarios to be produced, including:

- No DSM – no energy efficiency or demand response
- Energy Efficiency – without demand response
- Demand Response – without energy efficiency

These scenarios are analyzed relative to the ‘with DSM’ scenario, which includes both energy efficiency and demand response.

Demand response programs are associated with demand savings and are assumed to have no energy savings. This assumption implies that demand response programs cause customers to shift energy consumption to off-peak times, but no energy or energy-related costs are avoided. Demand response programs are assumed to be well-targeted to the extent that demand-related savings reduce class coincident peak and non-coincident peak demands.

Demand response programs are assumed to have an average measure life of one year. Energy and demand savings from energy efficiency programs persist for multiple years, but demand response program savings are assumed to impact only the year in which the program was implemented. A demand response program that is in place for multiple years is treated as a distinct program in each year. For example, a demand response program that is in place for three years is included as a program with a one-year average measure life in each of the three years. This modelling approach is representative of what would occur if demand response programs do not continue beyond the years being analyzed (i.e. 2023-2025). In order for demand response benefits to occur beyond 2025, further investment is required; this differs from energy efficiency where once the first-year investment is made, savings can generally be assured for the lifetime of the measure without further programmatic intervention being required. It should be noted that, if the full demand response program life of 10 years was modelled (i.e. 2022-2031) rather than three years (i.e. 2023-2025) then it’s likely the rate and bill impact results would improve because there are more up-front costs required in the early years related to recruiting customers and bringing new capacity online.

Specifically, within the NS Power Rate Model, demand response costs, savings, and average measure lives are included in the ‘E1 Data Inputs’ tab. The data is referenced in the ‘Simulated DSM Data Inputs’ tab,

which is the source of DSM data used in the 'Savings' tabs, for each class, and the 'COSS DSM Simulated' tab. Demand response data is used when either the 'no DSM' or 'Energy Efficiency' (No Demand Response)" scenarios are selected in 'E1 Data Inputs' (cell C2). When one of these scenarios is selected, the MW avoided from demand response programs are added back to the 'COSS DSM Simulated' tab and the associated demand response program costs are removed. Relative to the 'COSS DSM Benchmark' tab, which provides the 'with DSM' scenario, adding back avoided savings adds avoided costs to the 'COSS DSM Simulated' tab. With the incremental DSM costs associated with demand response also removed, the 'COSS DSM Simulated' tab will provide a scenario without demand response. The resulting class revenue requirements and unit costs of the 'COSS DSM Benchmark' and 'COSS DSM Simulated' tabs then reflect the impacts of demand response.

The results of the four scenarios (No DSM, DSM, energy efficiency, and demand response) are then copied to the E1 RBIA Model. The scenarios can be selected in the 'Inter-class Outputs' tab (cells D1:D2) and the results will show differences between the scenarios selected.

In E1's RBIA Model, annual customer incentive payments are an input and are assumed to behave as participant bill reductions. Demand response incentive payments are made to compensate participants for participating in demand response, not to offset other participant costs. In many jurisdictions it is common for demand response incentive payments to be provided to participants as on-bill credits.

The NS Power Rate Model uses forecast savings and avoided cost figures to derive distinct revenue requirement scenarios, and it approximates NS Power's cost allocation methodology to derive class-specific revenue requirements in those scenarios. The class-specific revenue requirements are used to derive unit costs (¢/kWh) for each class that are used as an approximation for unit revenues. Typical rate design would further divide class revenue requirements for most classes into demand-related and energy-related revenue requirements to produce separate ¢/kW and ¢/kWh rates. The model directly estimates total bill impacts for average customers (a customer with average demand and average consumption), so this additional step is not required.

The extent to which actual rates are aligned with unit costs depends on revenue rebalancing and rate design that occurs only in rebasing years. The results of the RBIA model therefore reflect impacts in rebasing years,

1 which is when avoided costs and lost revenue impacts will be realized by NS Power customers and issues
2 related to class cross-subsidization are relevant.

3
4 Savings related to energy efficiency programs are correlated with similar reductions to the associated billing
5 determinants. This means a class's energy and demand savings reduce the class's contribution to costs and
6 the revenues recovered from that class. This is not the case with demand response programs, for which
7 savings have minimal impacts on billing determinants. However, this is only relevant in non-rebasing years.

8
9 Though demand response does not meaningfully impact a class's billing determinants, the avoided costs
10 realized from demand reductions will be properly attributed to the class. The reduction of revenues from
11 a class will not come from a reduction in consumption at a given rate, but rather a reduction in the class-
12 specific revenue requirement that will translate to lower bills after rebasing.

5. 2023-2025 SETTLEMENT PLAN ANALYSIS RESULTS

The results in this section are for the Settlement Plan. All impacts are calculated relative to a scenario where no DSM is conducted in 2023-2025. Results are summarized in Attachment 1, for both the Settlement Plan and Alternate Scenario, and have been presented for EE and DR separately, as well as combined. Summary sheets for rate, bill, and participation impacts for each applicable rate class are included in Attachment 2 for the Settlement Plan, and Attachment 3 for the Alternate Scenario. The graphs presented on the summary sheets have been selected based on representative outputs from the model.

5.1 OVERALL RATE IMPACTS

DSM can lower rates by avoiding different types of electricity system costs (avoided energy, capacity, transmission and distribution, and carbon costs). DSM may also increase rates, a result of recovering program costs as well as lost revenues due to reduced sales. All of these upward and downward pressure impacts on rates from DSM are examined in the 2023-2025 DSM Plan RBIA to identify the overall impact on rates to each rate class over the long-term. The impacts presented in the analysis should not be read to be the actual rate increases or decreases that are experienced by customers in any year; the important takeaway is the percentage variance between with DSM and no DSM scenarios.

The RBIA for the 2023-2025 DSM Settlement Plan demonstrates the following rate impacts associated with DSM activities:

- average rate impacts (by rate class) over the study period (2023-2039) range from -0.1 to +1.0 percent (shown in Figure 2);
- average rate impacts (by rate class) over those years where DSM program costs are recovered (2023-2025) range from +1.8 to +5.0 percent; and
- average rate impacts (by rate class) over the study period following DSM program cost recovery (2026-2039) range from -0.5 to +0.3 percent.

Figure 2: Average Rate Impacts (2023-2039) as a Result of DSM Activities in 2023-2025 (Settlement Plan)

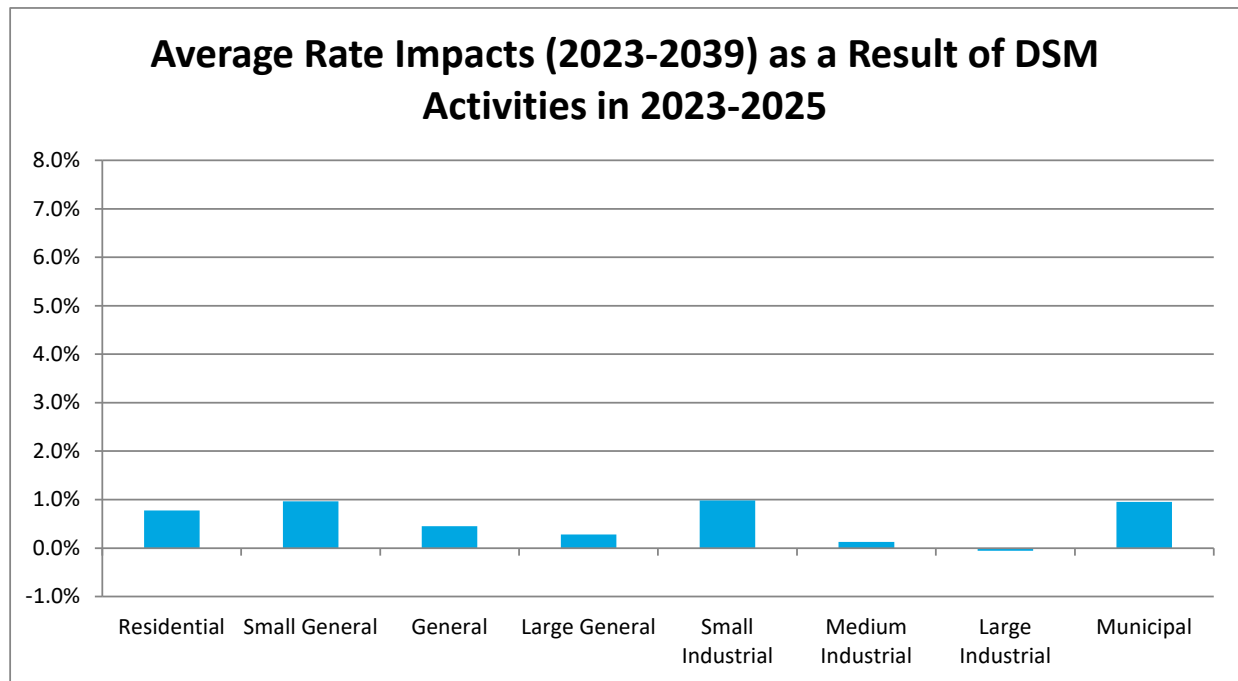
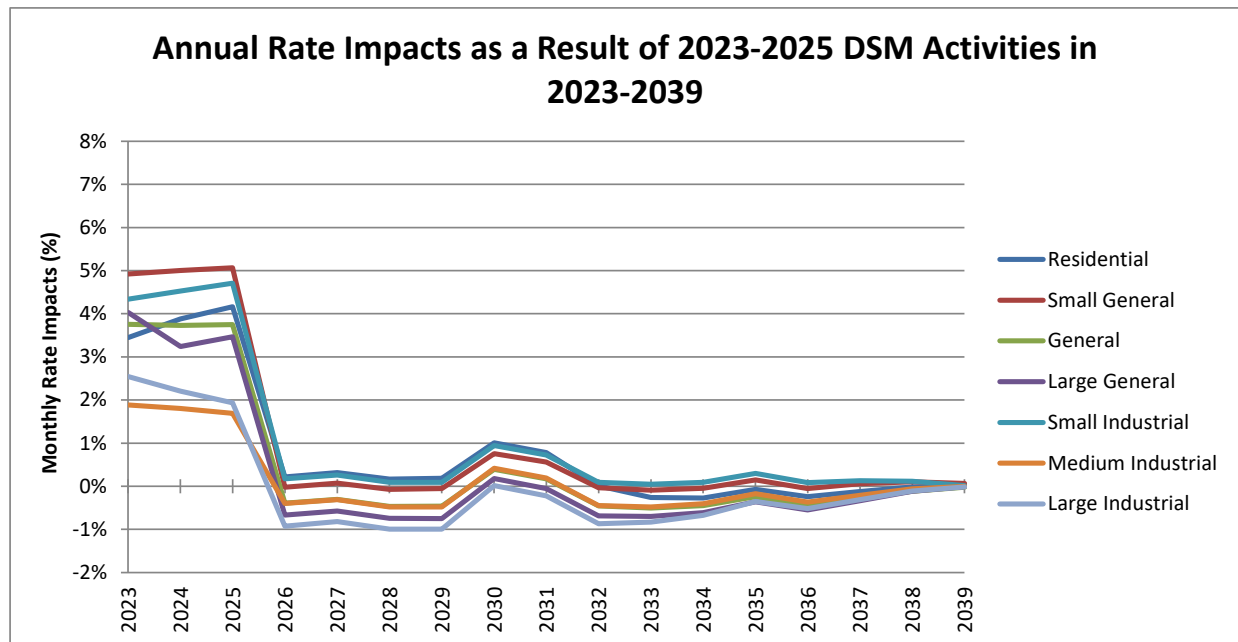


Figure 3 illustrates the annual rate effects (difference between the no-DSM scenario and the DSM scenario for each year), assuming that rates change every year. Changes in rate impacts are driven by two main factors: whether DSM program costs are being recovered, and fluctuations in annual avoided costs. The annual impacts depicted in Figure 3 should not be interpreted to be the actual rate changes that will occur in these years as experienced by customers.

Figure 3: Annual Rate Impacts (2023-2039) as a Result of 2023-2025 DSM Activities (Settlement Plan)



NS Power's RBIA Pricing Methodology (Attachment 5) discusses the generic COSS results, including why there are different rate impacts over time and why rate impacts differ between rate classes. Notably, NS Power explains that "classes whose total cost of service bear a relatively higher share of fuel costs, such as the Large Industrial, Municipal, Medium Industrial, and Large General, see higher reduction rate benefits due to the DSM-induced reduction in system costs because more of the utility cost savings come from the reduced fuel consumption than lower utilization of its fixed cost infrastructure. The opposite holds true for rate classes with higher responsibility for the fixed infrastructure costs such as the Domestic and Small General Classes."⁷

Another factor in the variation of rate impacts over time is the simplification of lifetime savings to a single weighted-average measure life within each class, and again for the system total, which introduces discontinuous jumps in savings, and which would not be experienced in reality. For example, the model assumes that all Residential measures installed in 2025 have a lifespan of exactly 8.1 years, after which the annual load reduction caused by those measures reappears. In actuality, the lifespan of measures within that class varies widely, and the load reduction will most often never reappear (although it would no longer be accredited to E1's resource acquisition activities, which is the context of this analysis).

⁷ Attachment 5, NS Power, Methodology for determination of changes in NS Power's base cost rates as a result of DSM-induced changes in class usage and total system costs, page 8.

Table 7 presents the average rate impacts over the study period (the same values as in Figure 2) compared to the rate impacts from the 2020-2022 Preferred Plan RBIA. There are a number of differences between the 2020-2022 RBIA and the 2023-2025 RBIA, including but not limited to:

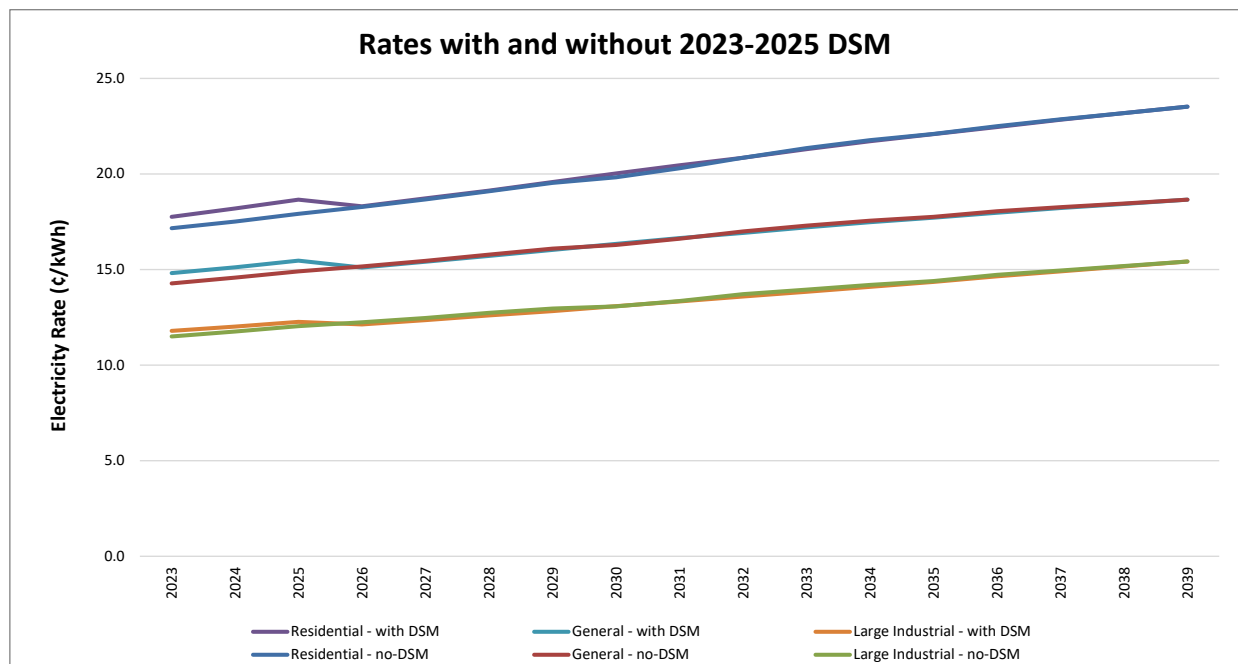
- Savings and investment levels
- Rate calculation methodology (RBIA now employs NS Power's Rate Model)
- Avoided costs updates
- Study period differences (16 years for the 2020-2022 RBIA; 17 years for the 2023-2025 RBIA)
- Changes to load forecasts, customer counts, rates etc.
- Integration of demand response

Table 7: Average Rate Impact compared to No-DSM Scenario, 2020-2022 Preferred Plan to 2023-2025 DSM Plan Results Comparison

Rate Class	2020-2022 Preferred Plan RBIA Result (average rate impact over 2020-2035)		2023-2025 Settlement Plan RBIA Result (average rate impact over 2023-2039)	
	(cents/kWh)	(%)	(cents/kWh)	(%)
Residential	+0.136	+0.80%	+0.137	+0.78%
Small General	+0.175	+1.09%	+0.156	+0.96%
General	+0.145	+1.31%	+0.061	+0.45%
Large General	+0.152	+1.52%	+0.030	+0.28%
Small Industrial	+0.174	+1.66%	+0.148	+0.98%
Medium Industrial	+0.066	+0.77%	+0.013	+0.13%
Large Industrial	+0.090	+1.00%	-0.014	-0.06%
Municipal	+0.090	+1.00%	+0.138	+0.95%

Figure 4 puts rate impacts from 2023-2025 DSM in context with other assumed rate impacts over the study period. Using the assumption that rates escalate by two percent per year for years when they are not explicitly known, rates will rise by 37 percent (Residential class) over the study period due to factors other than DSM. Both the DSM and no-DSM rates are shown in Figure 4 for three representative classes: Residential, General and Large Industrial. The pattern is similar for the other classes.

Figure 4: Rates with and without 2023-2025 DSM for three classes (Settlement Plan)



5.2 OVERALL BILL IMPACTS

Generally speaking, ratepayers that participate in DSM programs directly benefit by reducing their electricity consumption and thereby lowering their electricity bills. Together, the level of reduced consumption (or lack thereof in the case of non-participants) and the rate impacts, determine the bill impacts of DSM on customers.

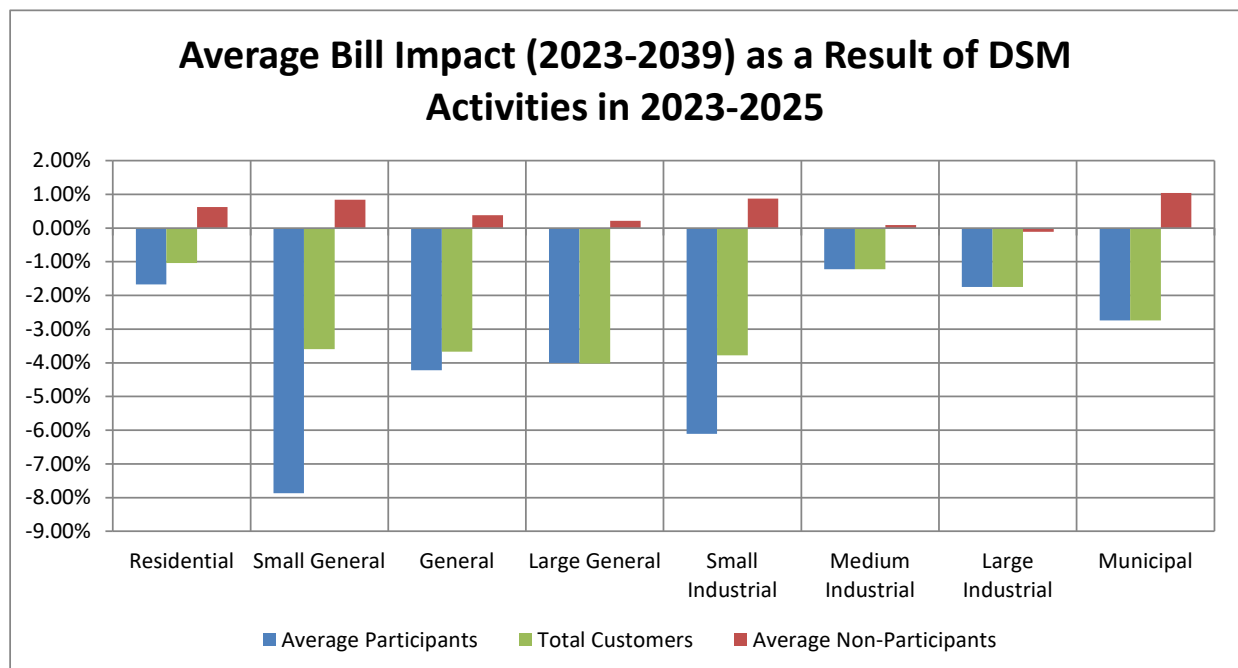
The 2023-2025 DSM Settlement Plan RBIA demonstrates the following bill impacts associated with DSM activities:

- average participant bill impacts (by rate class) over the study period (2023-2039) range from -7.9 to -1.2 percent;
- average non-participant bill impacts (by rate class) over the study period (2023-2039) range from -0.1 to +1.0 percent;
- average total customers bill impacts (by rate class) over the study period (2023-2039) range from -4.0 to -1.0 percent; and
- net impacts to Nova Scotia ratepayers are \$0.4 billion⁸ in savings as a result of a reduction in revenue requirement from DSM programs implemented in 2023-2025.

⁸ \$376.9M net benefits (EE) + (-\$8.2M) net benefits (DR) = \$368.8M total net benefits

Average bill impacts for participants, non-participants and total customers are presented in Figure 5, by rate class. Variations in average participant savings between classes reflect the ability of a typical energy efficiency project (i.e. a project with a statistically average level of savings) to impact a customer's total bill. Generally, participants in lower-consumption classes can lower their bills by a significant amount through installation of relatively simple lighting, heating, and hot water measures. Implementing these same simple measures for participants in higher-consumption classes, particularly medium and large industrial, typically lowers the bill by a smaller proportion, as a significant portion of their electricity consumption is tied to industrial processes that are more complex in nature.

Figure 5: Average Bill Impact (2023-2039) as a Result of DSM Activities in 2023-2025 (Settlement Plan)



When examining non-participant bill impacts, it is important to note the broad reach of E1's point-of-sale rebate program components, Instant Savings and the Instant Rebates portion of Business Energy Rebates (BER-IR). These offerings provide discounts on products that can be installed in every home and business; in larger classes it is assumed that each customer does participate every year, either directly or indirectly through contractors that perform work in their facilities. The result is that there are likely very few actual non-participants in the General, Large General, Medium Industrial, Large Industrial and Municipal classes. Additionally, for an average-consumption customer in any class, the non-participant results represent a 'minimum savings' scenario, where zero DSM savings are included, whereas the participant results

represent an ‘average-savings’ scenario. Consequently, the various depths of savings achieved do not all occur *between* the non-participant and participant results; roughly half of participants save more than the participant results shown.

5.3 OVERALL PARTICIPATION IMPACTS

Figures 6 through 9 present actual participation for 2011-2020 and estimates for 2021 through 2025. The estimates for 2021 and 2022 are the same as used in the revised historical 2021 RBIA (filed 20 January 2022). Two types of participation figures are presented – tracked and untracked. Tracked participants are those for which E1 has had direct contact with the customer and has collected identifying information such as address and NS Power account number. Untracked participants are those for which E1 has not collected such identifying information, who participate in point-of-sale programs such as Instant Savings and BER-IR.

Cumulative participation is presented in Figure 6 (tracked participants only) and Figure 7 (tracked plus untracked participants), including estimates of participation for 2021-2025.

Figure 6: Cumulative Participation Rates by Rate Class (tracked only) (Settlement Plan)

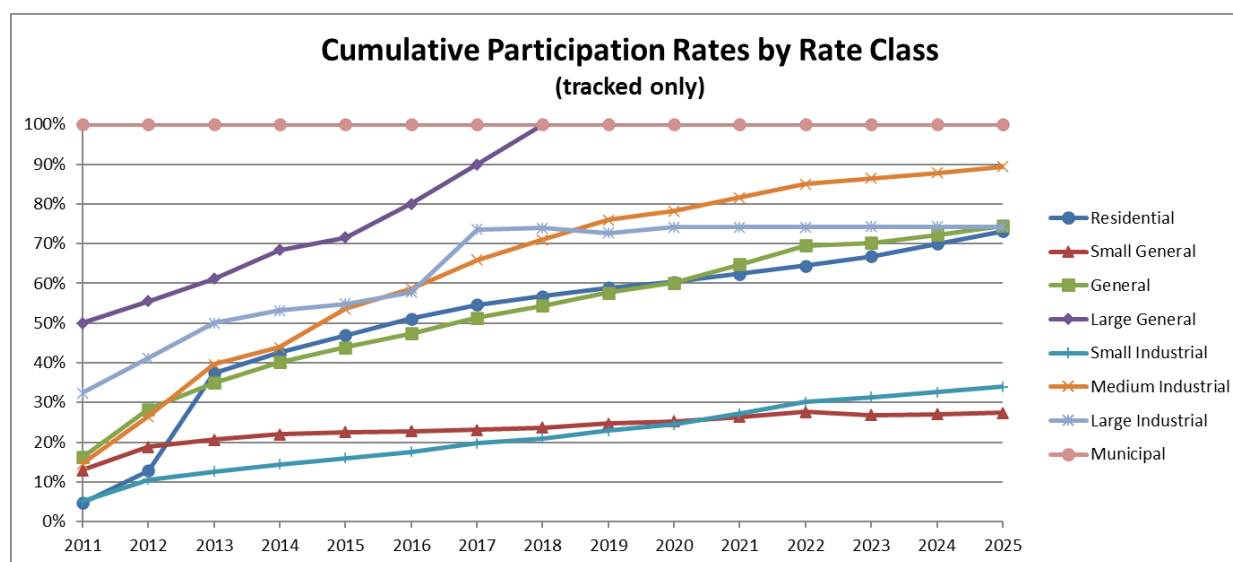
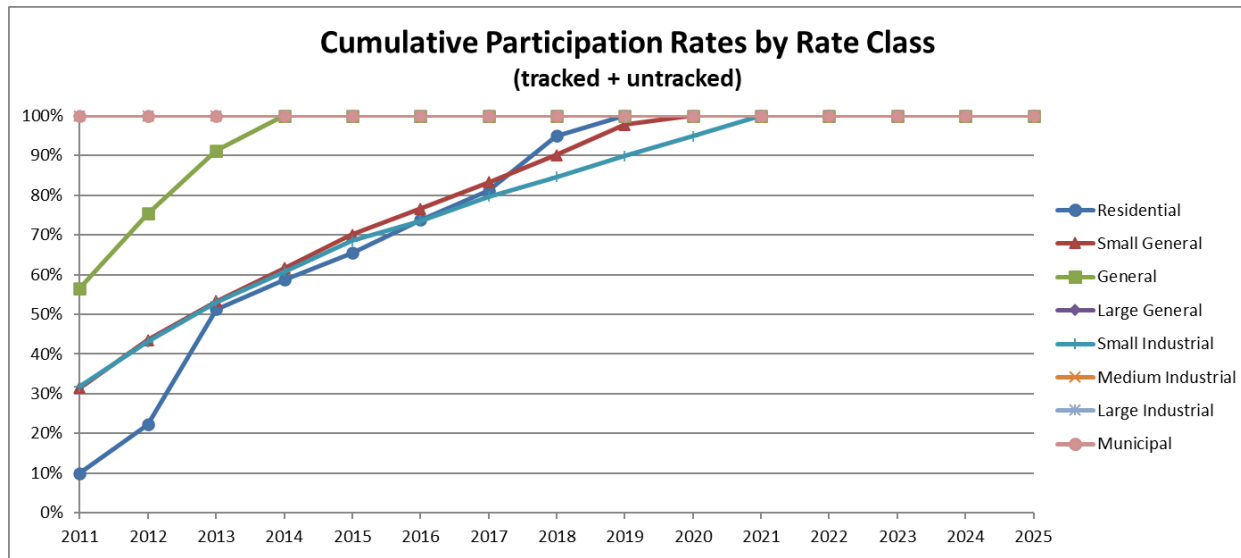


Figure 7: Cumulative Participation Rates by Rate Class (tracked + untracked) (Settlement Plan)



E1 employs the assumption that all customers in the Large General, Medium Industrial, Large Industrial and Municipal classes participate in BER-IR each year, so these classes show 100 percent participation in Figure 7 for all years. The other, smaller-customer-consumption classes show that cumulative participation rates have been steadily climbing since 2011. Figure 8 and Figure 9 present annual participation rates.

Figure 8: Annual Participation Rates by Rate Class (tracked only) (Settlement Plan)

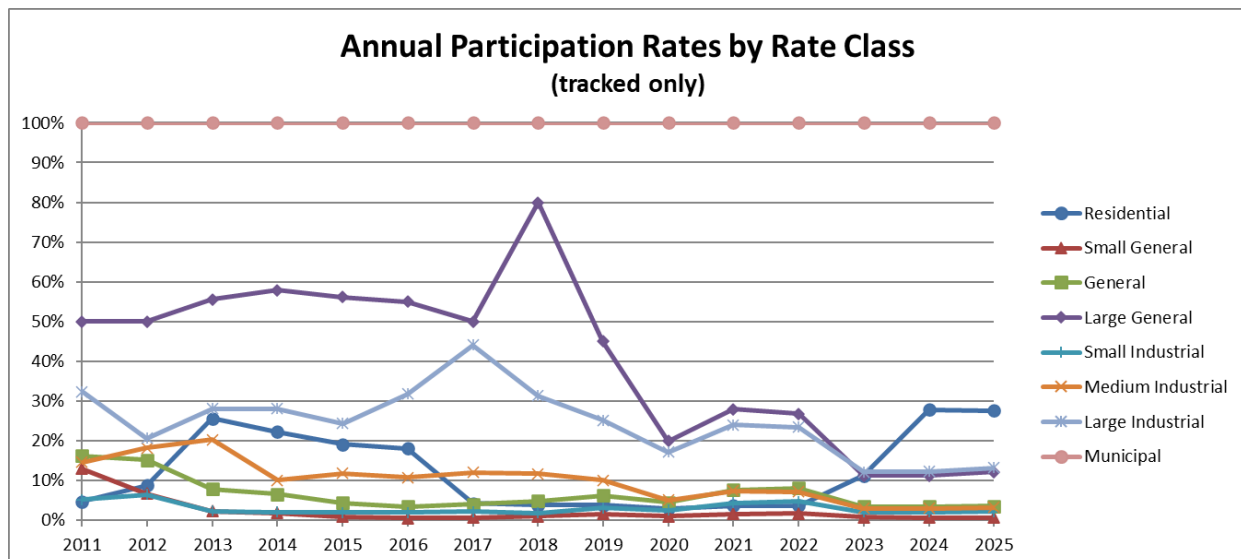
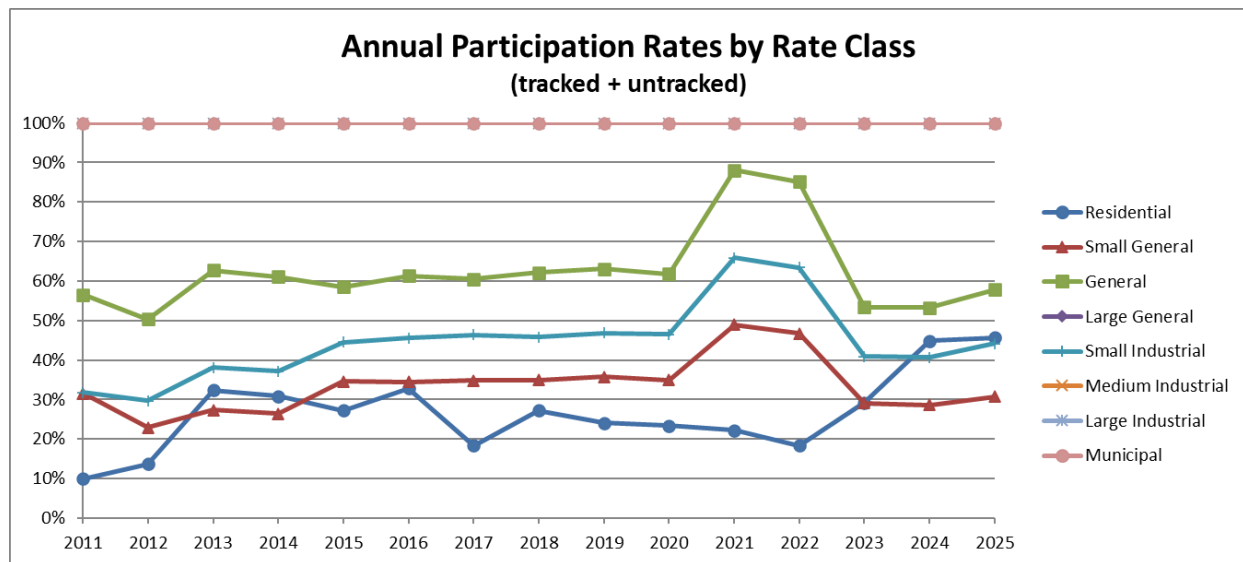


Figure 9: Annual Participation Rates by Rate Class (tracked + untracked) (Settlement Plan)



5.4 RESULTS BY RATE CLASS

This section highlights results in more detail, by individual rate class for the Settlement Plan.

5.4.1 RESIDENTIAL

- As modelled, the Residential class includes Rate Codes 2, 3, 6, 9 and 16 (Domestic), as well as 4 and 5 (Charitable).
- The average rate impact over the study period is an increase of 0.8 percent, or 0.14 cents/kWh.
- Participants in the Residential class see an average bill decrease of 1.7 percent over the study period.
- Non-Participants see an average bill increase of 0.6 percent over the study period.
- The class overall sees an average bill decrease of 1.0 percent over the study period.

Residential

↑ 0.8% Rates
 ↓ 1.7% Participant Bills
 ↑ 0.6% Non-Participant Bills
 ↓ 1.0% Total Customer Bills

5.4.2 SMALL GENERAL

- As modelled, the Small General class includes Rate Code 10 only.
- The average rate impact over the study period is an increase of 1.0 percent, or 0.16 cents/kWh.

Small General

↑ 1.0% Rates
 ↓ 7.9% Participant Bills
 ↑ 0.8% Non-Participant Bills
 ↓ 3.6% Total Customer Bills

- Participants in the Small General class see an average bill decrease of 7.9 percent over the study period.
- Non-Participants see an average bill increase of 0.8 percent over the study period.
- The class overall sees an average bill decrease of 3.6 percent over the study period.

5.4.3 GENERAL

- As modelled, the General class includes Rate Code 11 only.
- The average rate impact over the study period is an increase of 0.5 percent, or 0.06 cents/kWh.
- Participants in the General class see an average bill decrease of 4.2 percent over the study period.
- Non-Participants see an average bill increase of 0.4 percent over the study period.
- The class overall sees an average bill decrease of 3.7 percent over the study period.

General

↑ 0.5% Rates
 ↓ 4.2% Participant Bills
 ↑ 0.4% Non-Participant Bills
 ↓ 3.7% Total Customer Bills

5.4.4 LARGE GENERAL

- As modelled, the Large General class includes Rate Code 12 only.
- The average rate impact over the study period is an increase of 0.3 percent, or 0.03 cents/kWh.
- Participants in the Large General class see an average bill decrease of 4.0 percent over the study period.
- Non-Participants see an average bill increase of 0.2 percent over the study period.
- The class overall sees an average bill decrease of 4.0 percent over the study period.

Large General

↑ 0.3% Rates
 ↓ 4.0% Participant Bills
 ↑ 0.2% Non-Participant Bills
 ↓ 4.0% Total Customer Bills

- In this rate class, all customers are assumed to participate in BER-IR each year, so cumulative participation reaches 100 percent in 2023. For this reason, the bill effects for the participant group reflect the bill effects for total customers. The non-participant line is still shown, even though no non-participants may exist in the rate class.

5.4.5 SMALL INDUSTRIAL

- As modelled, the Small Industrial class includes Rate Code 21 only.
- The average rate impact over the study period is an increase of 1.0 percent, or 0.15 cents/kWh.
- Participants in the Small Industrial class see an average bill decrease of 6.1 percent over the study period.
- Non-Participants see an average bill increase of 0.9 percent over the study period.
- The class overall sees an average bill decrease of 3.8 percent over the study period.

Small Industrial

↑ 1.0% Rates
 ↓ 6.1% Participant Bills
 ↑ 0.9% Non-Participant Bills
 ↓ 3.8% Total Customer Bills

5.4.6 MEDIUM INDUSTRIAL

- As modelled, the Medium Industrial class includes Rate Code 22 only.
- The average rate impact over the study period is an increase of 0.1 percent, or 0.01 cents/kWh.
- Participants in the Medium Industrial class see an average bill decrease of 1.2 percent over the study period.
- Non-Participants see an average bill increase of 0.1 percent over the study period.
- The class overall sees an average bill decrease of 1.2 percent over the study period.
- In this rate class, all customers are assumed to participate in BER-IR each year, so cumulative participation reaches 100 percent participation in 2023. For this reason, the bill effects for the participant group reflect the bill effects for total customers. The non-participant line is still shown, even though no non-participants may exist in the rate class.

Medium Industrial

↑ 0.1% Rates
 ↓ 1.2% Participant Bills
 ↑ 0.1% Non-Participant Bills
 ↓ 1.2% Avg. Total Cust. Bills

5.4.7 LARGE INDUSTRIAL

- As modelled, the Large Industrial class includes Rate Code 23 (Large Industrial), Rate Code 25 (Large Industrial, interruptible service), and the one-part high voltage real time pricing tariff.
- The average rate impact over the study period is a decrease of 0.1 percent, or an average decrease of 0.01 cents/kWh.

Large Industrial

↓ 0.1% Rates
 ↓ 1.8% Participant Bills
 ↓ 0.1% Non-Participant Bills
 ↓ 1.8% Total Customer Bills

- Participants in the Large Industrial class see an average bill decrease of 1.8 percent over the study period.
- Non-Participants see an average bill decrease of 0.1 percent over the study period.
- The class overall sees an average bill decrease of 1.8 percent over the study period.
- In this rate class, all customers are assumed to participate in BER-IR each year, so cumulative participation reaches 100 percent participation in 2023. For this reason, the bill effects for the participant group reflect the bill effects for total customers. The non-participant line is still shown, even though no non-participants may exist in the rate class.

5.4.8 MUNICIPAL

- As modelled, the Municipal class includes Rate Code 24 only.
- The average rate impact over the study period is an increase of 1.0 percent, or 0.14 cents/kWh.
- Municipal utilities see an average bill decrease of 2.7 percent over the study period.
- Since there was participation in E1 programs from all Municipal Electric Utilities in each year of the DSM delivery period, the bill impacts for participants match those for total customers exactly. This is a simplification of the rate and bill effects for individual MEU customers, as their individual participation is not modelled in the analysis.

Municipal

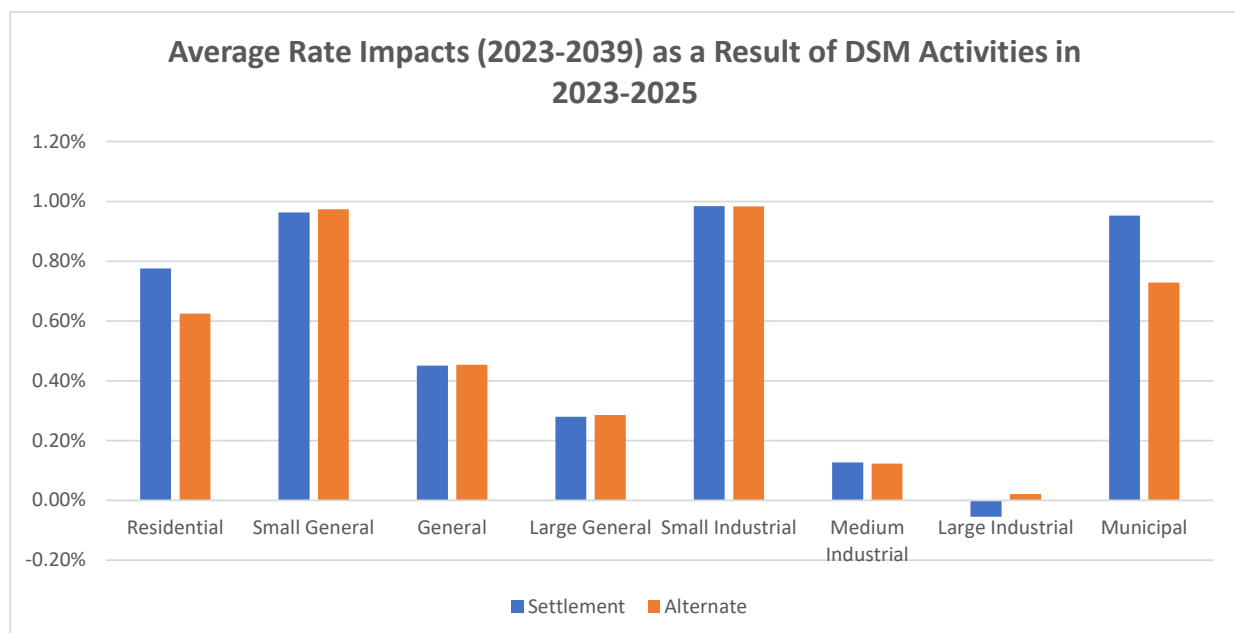
↑ 1.0% Rates
↓ 2.7% Average Bills

6. COMPARISON OF SETTLEMENT AND ALTERNATE PLANS

Full results, by rate class, are provided in Attachments 2 and 3 for the 2023-2025 Settlement Plan and Alternate Scenario, respectively. This section compares key outputs between the two.

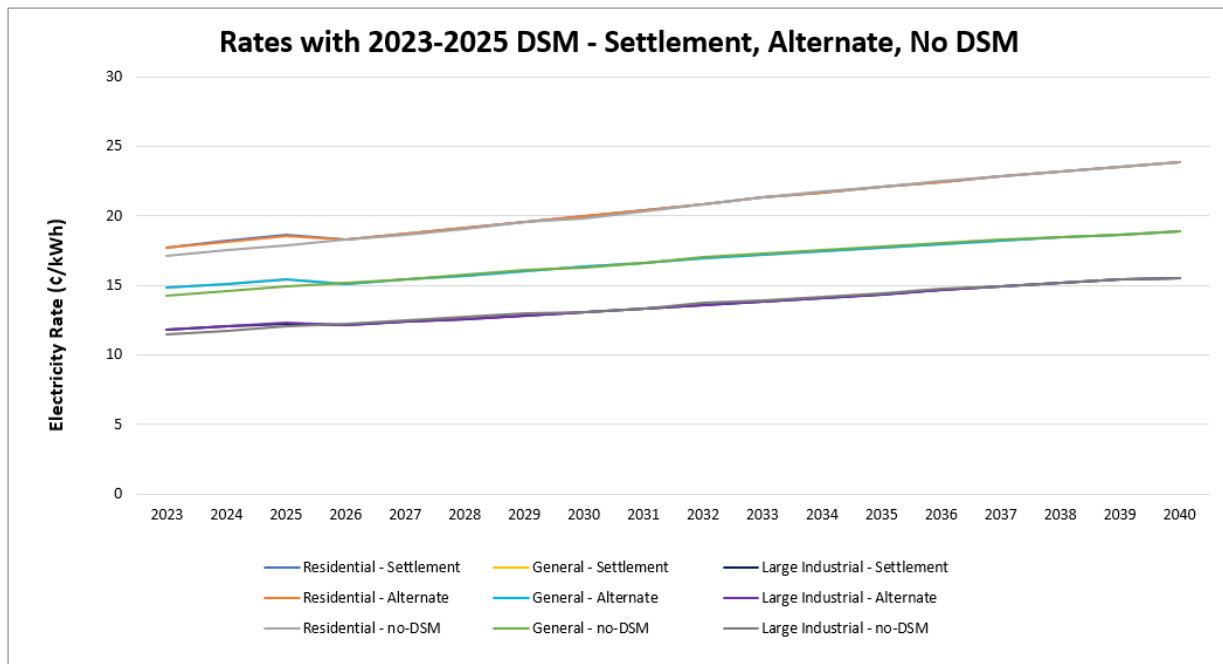
Rate impacts for both the Settlement Plan and Alternate Scenario are similar. On average across classes, the Settlement Plan produces average (2023-2039) rate impacts that are 0.04 percent higher than the Alternate Scenario, as shown in Figure 10. Since avoided costs and lost revenues are approximately in balance for each class in both, this difference in rate impacts is primarily driven by the difference in DSM program costs.

Figure 10: Average Rate Impacts (2023-2039) as a Result of DSM Activities in 2023-2025 (Settlement Plan vs. Alternate Scenario)



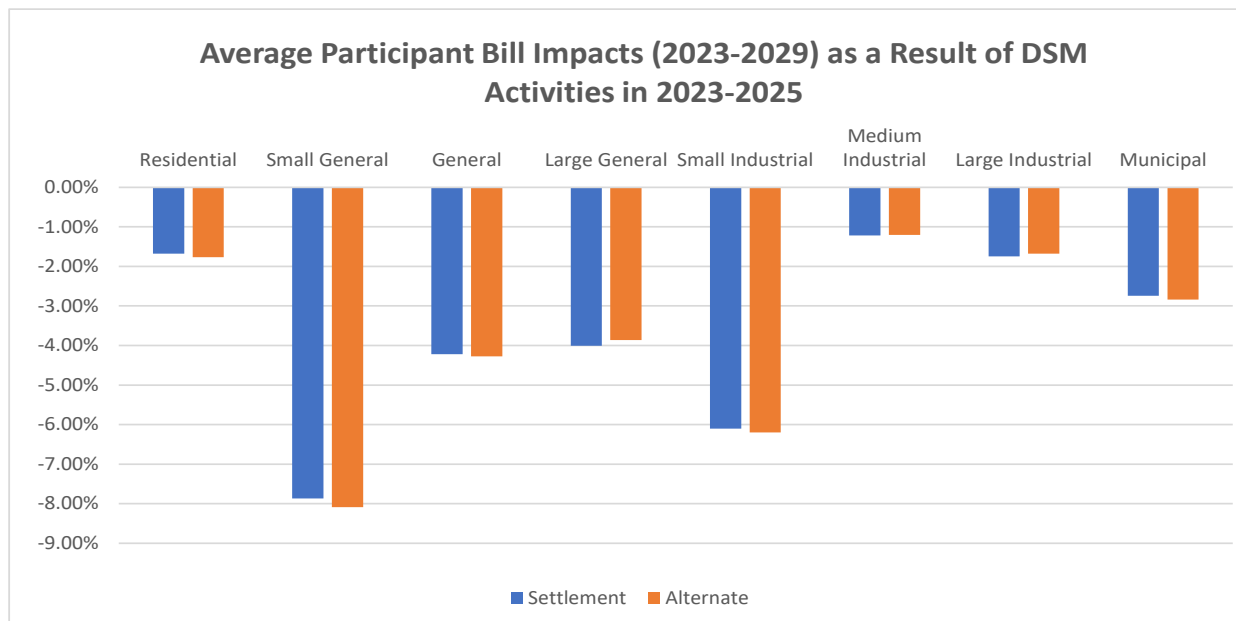
Full rates with DSM impacts are presented for three representative classes in Figure 11, for both the Settlement Plan, Alternate Scenario, and No DSM. The Settlement Plan and Alternate Scenario figures in this graph lay almost exactly on top of each other, as the rate impacts do not differ significantly between the two.

Figure 11: Rates with 2023-2025 DSM – Settlement, Alternate, No DSM Scenarios



Average participant bill impacts are presented in Figure 12 for both the Settlement Plan and Alternate Scenario. Since there is a different program mix in the Alternate Scenario with differing assumptions, there are minor differences in the average savings per participant.

Figure 12: Average Participant Bill Impact (2023-2039) as a Result of DSM Activities in 2023-2025 (Settlement Plan vs. Alternate Scenario)



- 1 As shown in the previous figures, the rate and participant bill impacts for the Settlement Plan and Alternate
- 2 Scenario are similar; the main difference is that under the Settlement Plan, a greater number of customers
- 3 would have the opportunity to participate.

7. FUTURE CONSIDERATIONS

E1 understands, from NS Power's January 2022 IRP Action Plan Update, that NS Power will be engaging with stakeholders in an Evergreen IRP Update in 2022. E1 will work with stakeholders to consider any potential implications to the RBIA as a result of this or future Evergreen IRP Updates, and how best to reasonably address in the RBIA.

On 27 January 2022, NS Power filed its 2022-2024 General Rate Application with the NSUARB. E1 will work with stakeholders to consider any implications to the RBIA as a result of the outcomes of this Matter, and how best to reasonably address them in the RBIA.

The next application of the RBIA model will be for the historical 2022 RBIA, filed in October 2022. E1 looks forward to working with stakeholders in advance of that filing.

8. CONCLUSION

Highlights from the 2023-2025 DSM Settlement Plan RBIA analysis include:

- Over the 17 years of the study period, participants in DSM programs see average annual bill reductions ranging from a low of 1.2 percent (typical Medium Industrial participant) to a high of 7.9 percent (typical Small General participant).
- Over the 17 years of the study period, the average bill impacts to non-participants (by rate class) range from -0.1 to +1.0 percent.
- Over the 17 years of the study period, the average upward rate pressure of DSM varies from a low of -0.1 to a high of 1.0 percent across all rate classes.
- Nova Scotian ratepayers will save \$0.4⁹ billion as a result of energy and demand reductions caused by 2023-2025 DSM programs.
- Maximizing customer participation in DSM programs mitigates rate impacts by increasing the number of customers who experience net bill reductions.

Through collaboration with the DSMAG and NS Power, E1's RBIA has evolved considerably over the last several years. Since the 2019 RBIA there have been substantial enhancements, notably the use of an expanded set of rate class allocation factors applied to system-level avoided costs and lost revenues for the 2019 RBIA, the removal of all cost allocation functionality from the E1 model to more accurately reflect NS Power's COSS in the 2020 RBIA, the use of updated avoided costs and incorporation of transfer tables and cost allocation summary tables in the NS Power Rate Model in the 2021 RBIA, and the integration of demand response in the 2023-2025 RBIA.

The RBIA for the 2023-2025 DSM Plan estimates the effects of 2023-2025 DSM programs on customer rates and bills throughout the full lifetime of the DSM impacts as compared to a no-DSM scenario, all else being equal. Over the lifetime of measures installed in this period, after accounting for DSM program costs, utility avoided costs, and the reallocation of 'lost' fixed revenues, NS Power customers will save \$0.4 billion on electricity bills.

It is important to recognize that the RBIA is not intended to represent a comprehensive evaluation of total DSM impacts. The model excludes benefits that do not directly impact rates or bills, such as the societal

⁹ \$376.9M net benefits (EE) + (-\$8.2M) net benefits (DR) = \$368.8M total net benefits

benefits of reduced greenhouse gas emissions, reduction of energy poverty, investment in local businesses that deliver efficiency services instead of investment in foreign fuel supplies, increased productivity in businesses, and increased occupant comfort in homes and businesses, among others.

DSM investments produce net benefits for Nova Scotian ratepayers over the long term, as demonstrated through cost-effectiveness testing using the Total Resource Cost (TRC) test and the Program Administrator Cost (PAC) test. However, these tests look at ratepayers as a whole, and do not examine to what degree non-participants may be subsidizing programs that mainly benefit participants. This RBIA subdivides each rate class into groups of participants and non-participants to examine impacts to their rates and more importantly to their total electricity bills, respectively.

Cost effective energy efficiency resources are generally understood to impact both electricity rates and bills. All ratepayers experience the rate impacts from DSM for their applicable rate class as described in Section 4. However, ratepayers will experience different bill impacts depending on whether they participate in E1's DSM programs, in which programs they participate, and how often they participate. One of the main benefits of DSM programs, the reduction of customer energy and demand consumption (i.e. lower bills), are only realized by participants in DSM programs. The analysis shows that on average, their reductions in consumption drive bill decreases that far outweigh the increases caused by higher rates. Thus, achieving higher participation rates through a broad portfolio of programs that addresses all customer types, including underserved and hard to reach markets, limits the number of customers that may only experience higher rates and who do not benefit from lower bills due to reduced consumption.

Filed Electronically

Appendix B

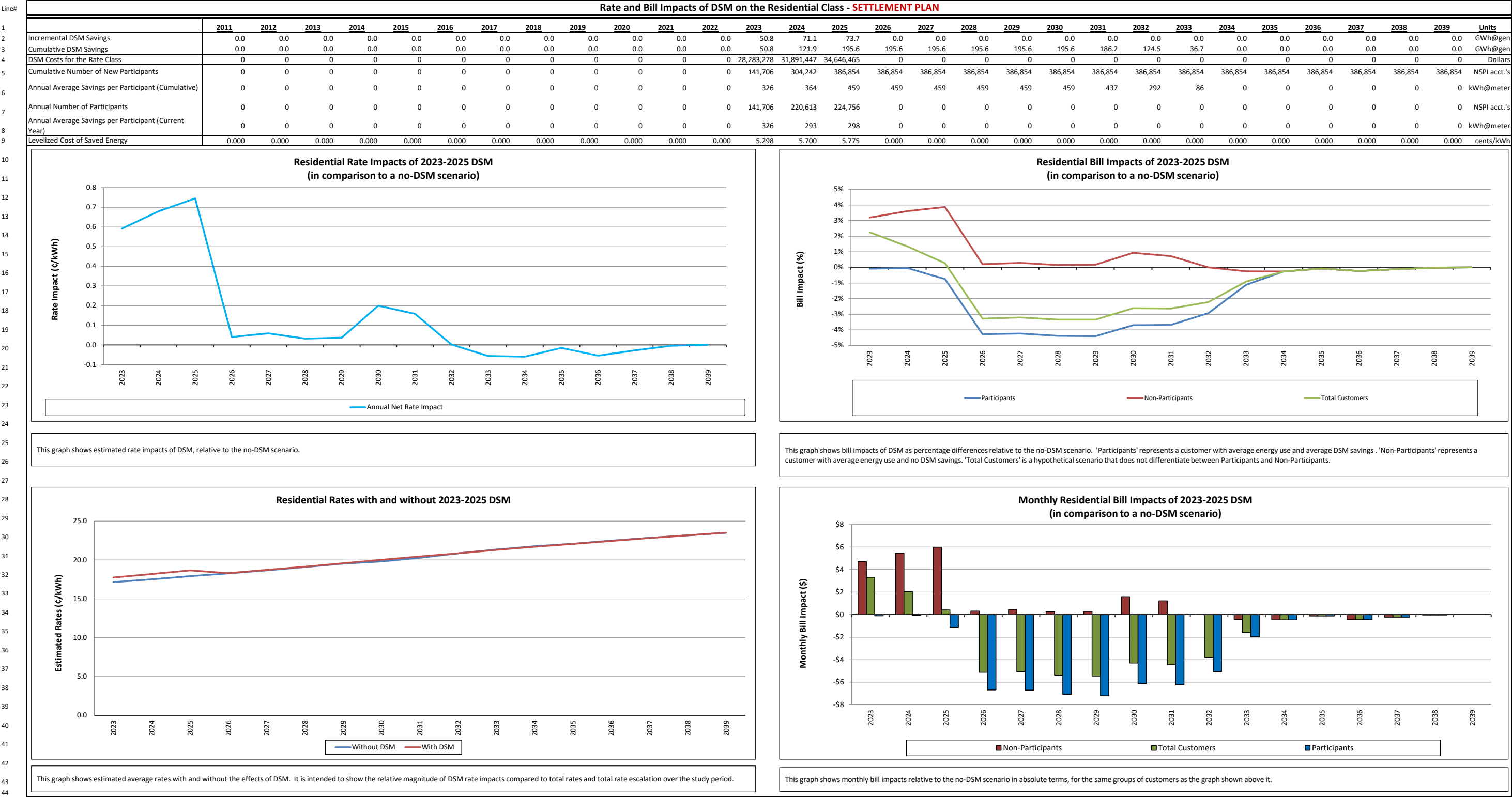
Attachment 1: 2023-2025 Summary Results

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Appendix B

Attachment 2: Results by Rate Class (Settlement Plan)

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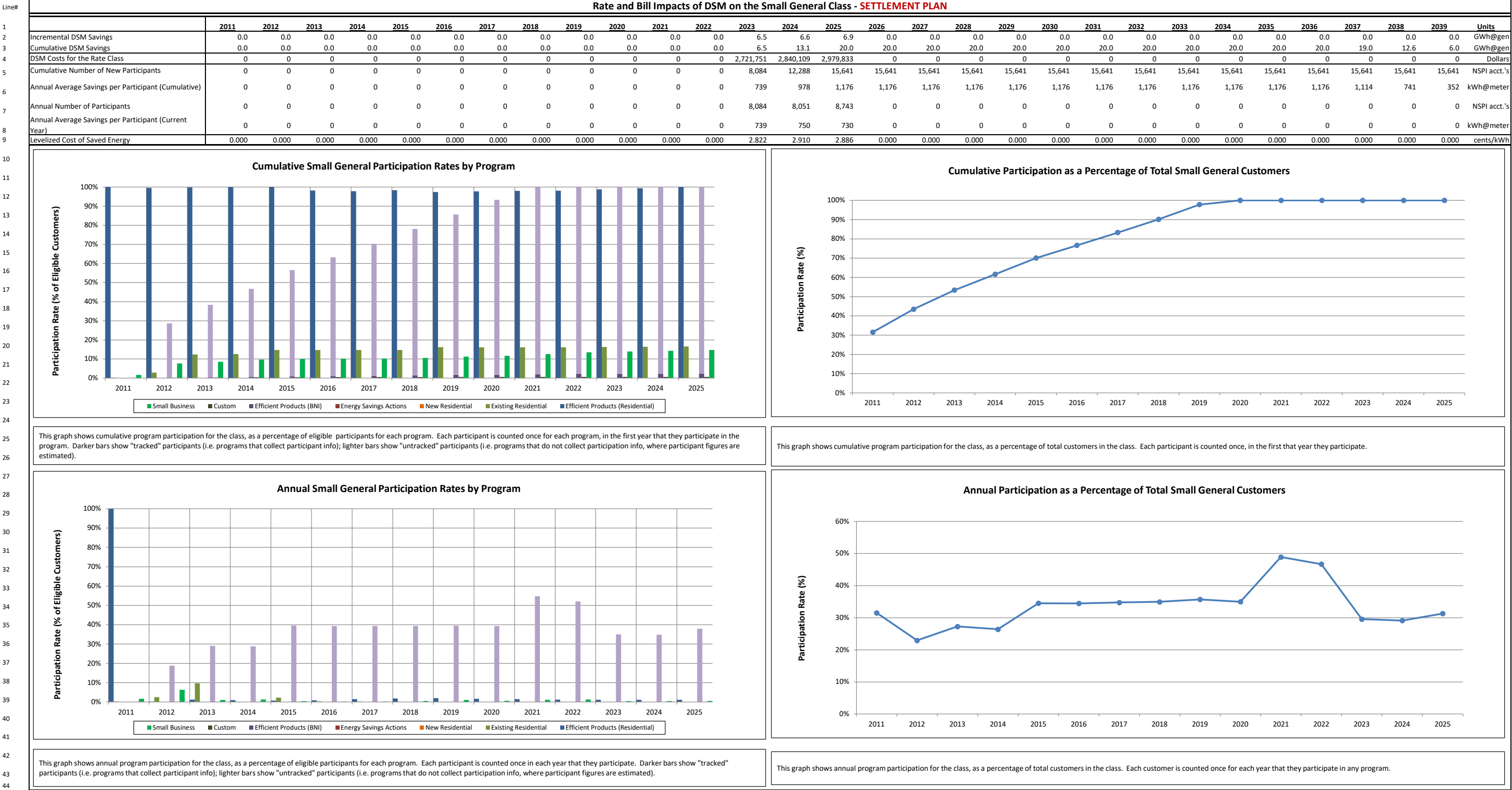


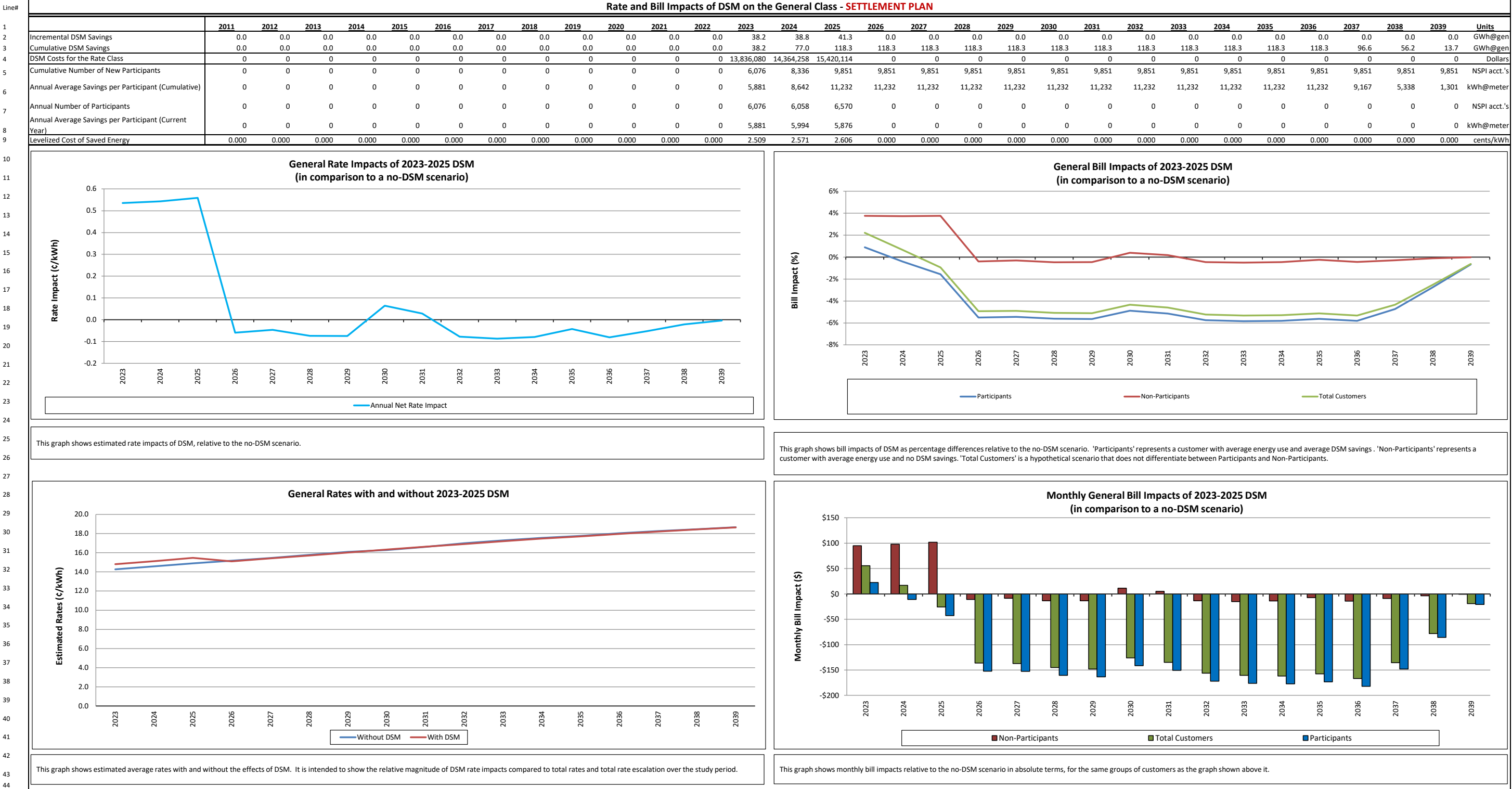
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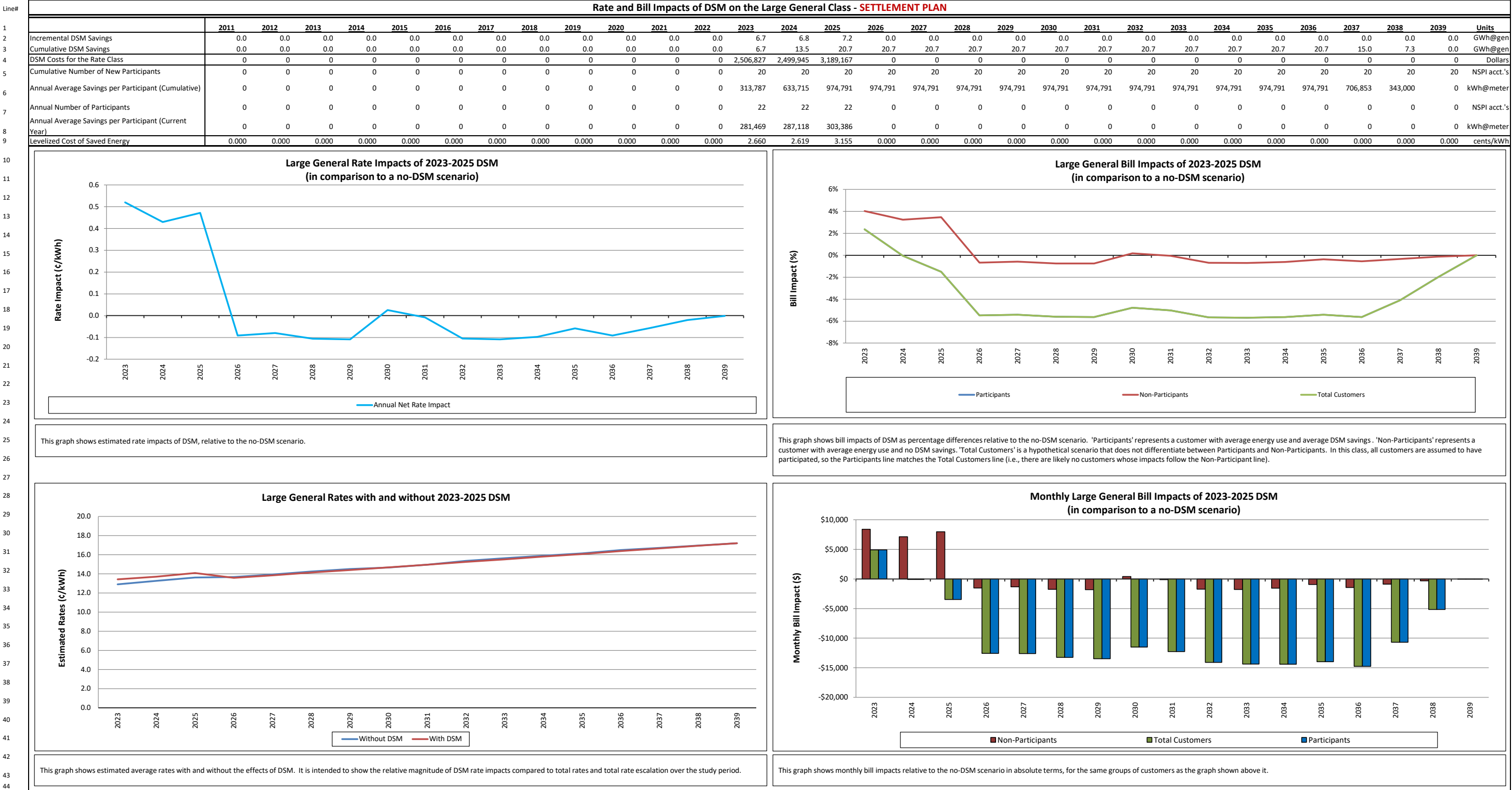


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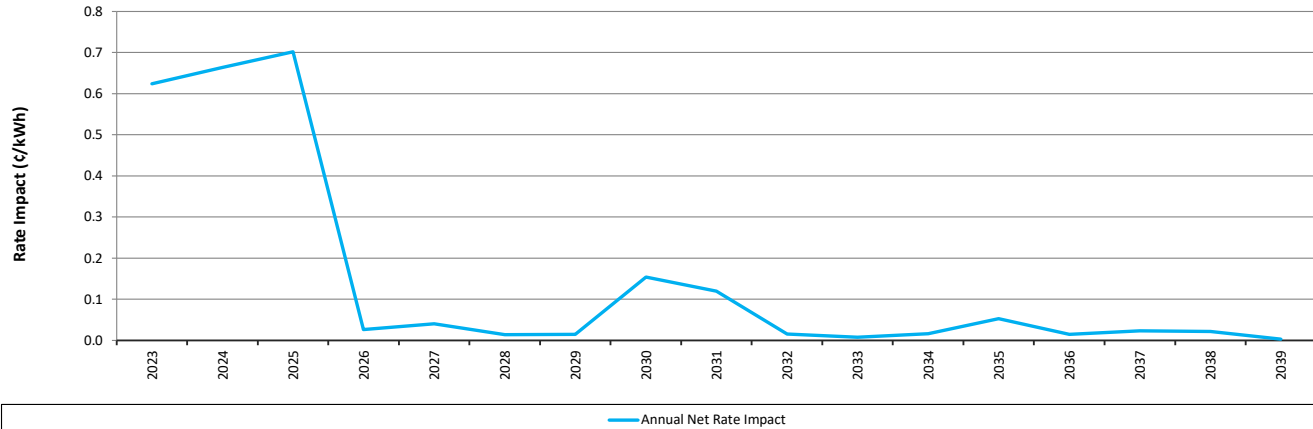
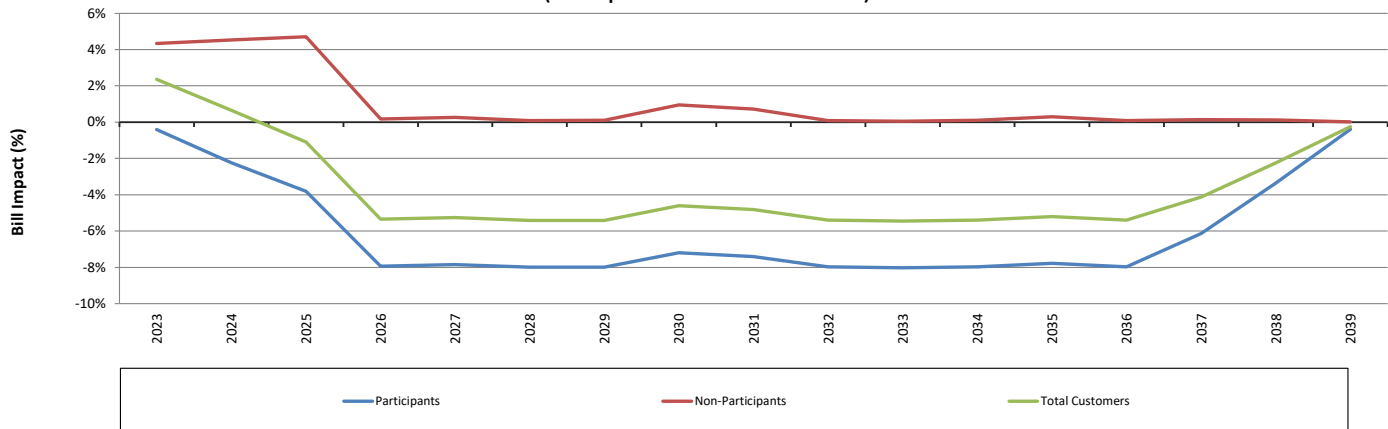
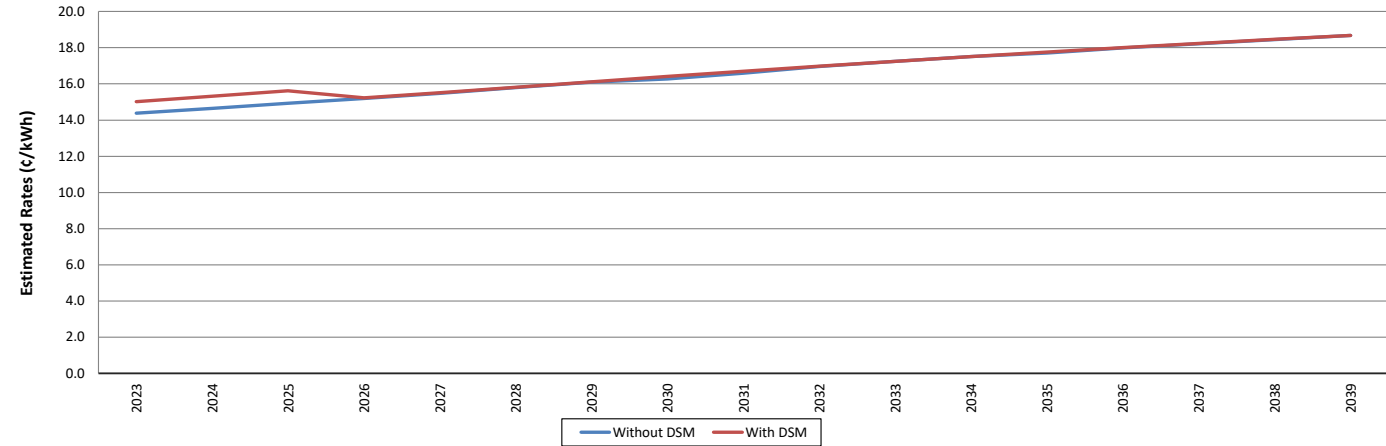
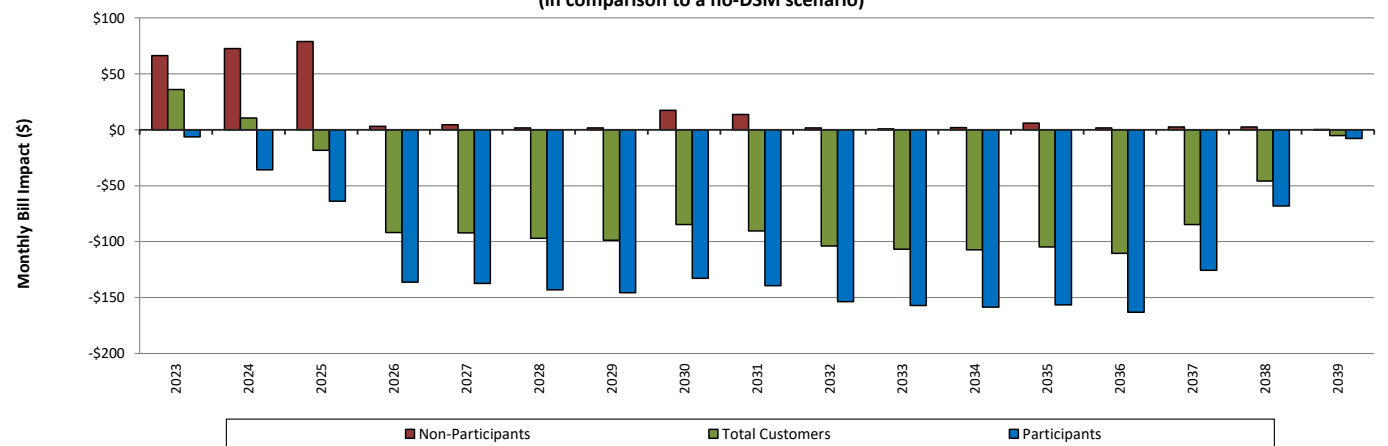
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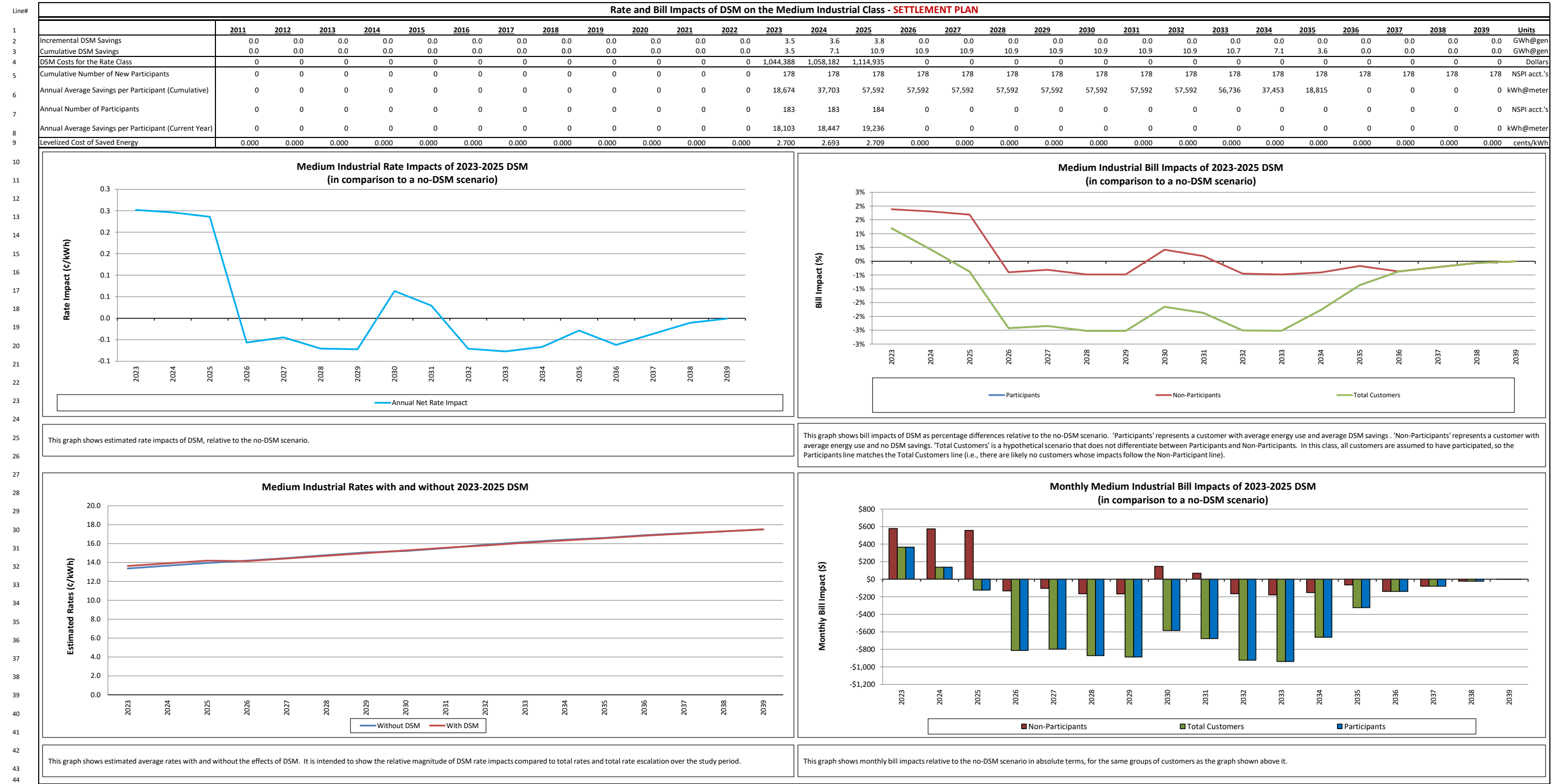






Line#	Rate and Bill Impacts of DSM on the Small Industrial Class - SETTLEMENT PLAN																														
1		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Units
2	Incremental DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	5.6	5.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	GWh@gen
3	Cumulative DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	11.1	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	13.1	7.1	0.8	GWh@gen
4	DSM Costs for the Rate Class	0	0	0	0	0	0	0	0	0	0	0	0	1,777,465	1,841,926	1,945,875	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Dollars
5	Cumulative Number of New Participants	0	0	0	0	0	0	0	0	0	0	0	0	890	1,226	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	1,459	NSPI acct.'s	
6	Annual Average Savings per Participant (Cumulative)	0	0	0	0	0	0	0	0	0	0	0	0	5,807	8,504	10,982	10,982	10,982	10,982	10,982	10,982	10,982	10,982	10,982	10,982	10,982	10,982	8,429	4,590	523	kWh@meter
7	Annual Number of Participants	0	0	0	0	0	0	0	0	0	0	0	0	890	887	962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	NSPI acct.'s
8	Annual Average Savings per Participant (Current Year)	0	0	0	0	0	0	0	0	0	0	0	0	5,807	5,933	5,821	0	0	0	0	0	0	0	0	0	0	0	0	0	0	kWh@meter
9	Levelized Cost of Saved Energy	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.269	2.320	2.314	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	cents/kWh
10	Small Industrial Rate Impacts of 2023-2025 DSM (in comparison to a no-DSM scenario)  Small Industrial Bill Impacts of 2023-2025 DSM (in comparison to a no-DSM scenario) 																														
23	This graph shows estimated rate impacts of DSM, relative to the no-DSM scenario. This graph shows bill impacts of DSM as percentage differences relative to the no-DSM scenario. 'Participants' represents a customer with average energy use and average DSM savings. 'Non-Participants' represents a customer with average energy use and no DSM savings. 'Total Customers' is a hypothetical scenario that does not differentiate between Participants and Non-Participants.																														
28	Small Industrial Rates with and without 2023-2025 DSM  Monthly Small Industrial Bill Impacts of 2023-2025 DSM (in comparison to a no-DSM scenario) 																														
41	This graph shows estimated average rates with and without the effects of DSM. It is intended to show the relative magnitude of DSM rate impacts compared to total rates and total rate escalation over the study period. This graph shows monthly bill impacts relative to the no-DSM scenario in absolute terms, for the same groups of customers as the graph shown above it.																														









Line#	Rate and Bill Impacts of DSM on the Large Industrial Class - SETTLEMENT PLAN																														
1		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Units
2	Incremental DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.1	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	GWh@gen
3	Cumulative DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	14.0	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	15.1	7.9	1.2	0.0	0.0	0.0	GWh@gen
4	DSM Costs for the Rate Class	0	0	0	0	0	0	0	0	0	0	0	0	2,244,539	2,269,732	2,408,038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Dollars
5	Cumulative Number of New Participants	0	0	0	0	0	0	0	0	0	0	0	0	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	NSPI acct.'s
6	Annual Average Savings per Participant (Cumulative)	0	0	0	0	0	0	0	0	0	0	0	0	190,127	382,586	585,061	585,061	585,061	585,061	585,061	585,061	585,061	585,061	585,061	412,835	216,510	33,585	0	0	0	kWh@meter
7	Annual Number of Participants	0	0	0	0	0	0	0	0	0	0	0	0	39	39	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	NSPI acct.'s
8	Annual Average Savings per Participant (Current Year)	0	0	0	0	0	0	0	0	0	0	0	0	169,775	171,790	179,384	0	0	0	0	0	0	0	0	0	0	0	0	0	0	kWh@meter
9	Levelized Cost of Saved Energy	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.900	2.903	2.903	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	cents/kWh
10	Cumulative Large Industrial Participation Rates by Program Cumulative Participation as a Percentage of Total Large Industrial Customers																														
25	This graph shows cumulative program participation for the class, as a percentage of eligible participants for each program. Each participant is counted once for each program, in the first year that they participate in the program. Darker bars show "tracked" participants (i.e. programs that collect participant info); lighter bars show "untracked" participants (i.e. programs that do not collect participation info, where participant figures are estimated).																														
26	This graph shows cumulative program participation for the class, as a percentage of total customers in the class. Each participant is counted once, in the first that year they participate.																														
27	Annual Large Industrial Participation Rates by Program Annual Participation as a Percentage of Total Large Industrial Customers																														
42	This graph shows annual program participation for the class, as a percentage of eligible participants for each program. Each participant is counted once in each year that they participate. Darker bars show "tracked" participants (i.e. programs that collect participant info); lighter bars show "untracked" participants (i.e. programs that do not collect participation info, where participant figures are estimated).																														
43	This graph shows annual program participation for the class, as a percentage of total customers in the class. Each customer is counted once for each year that they participate in any program.																														
44																															

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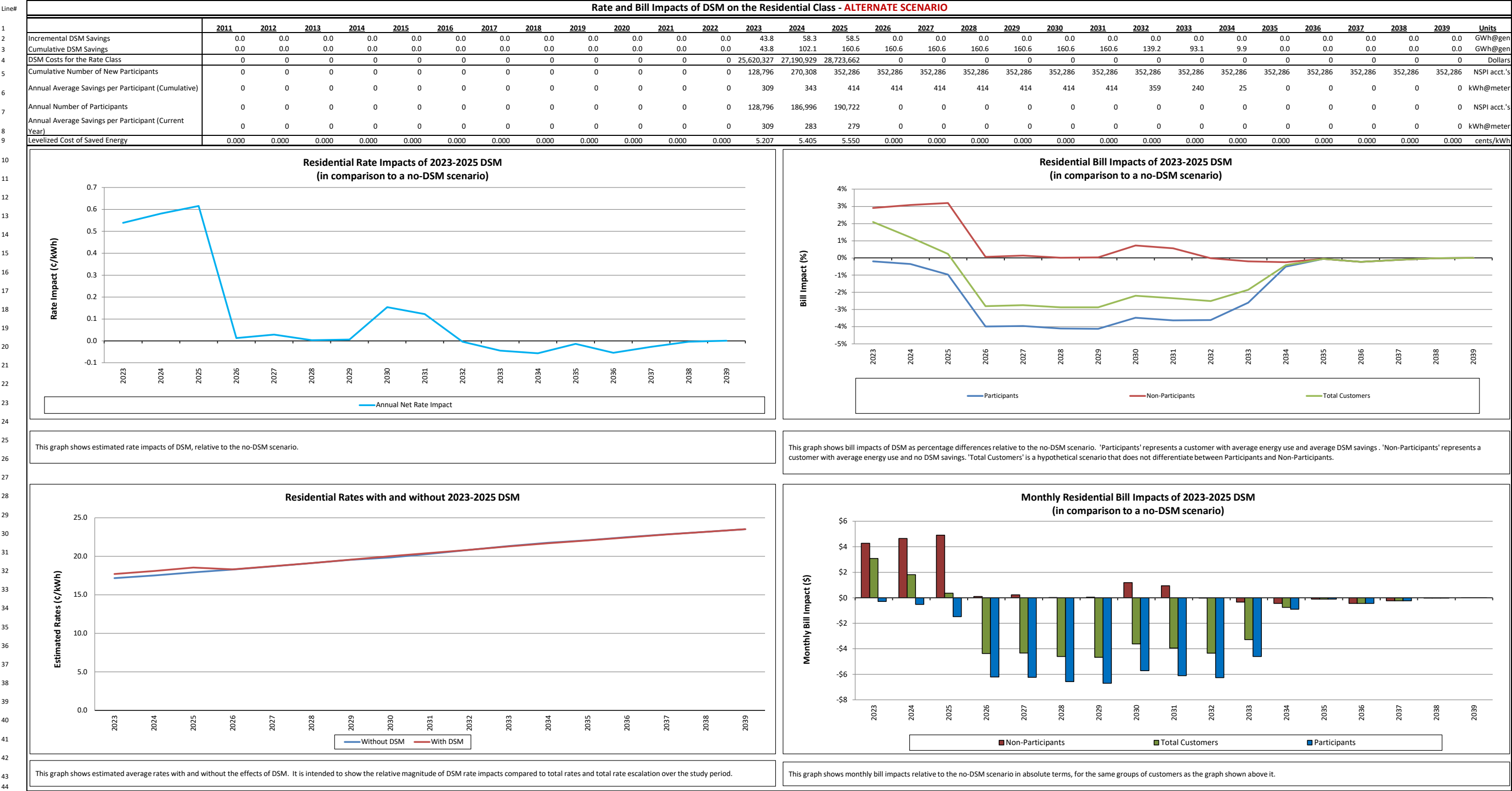
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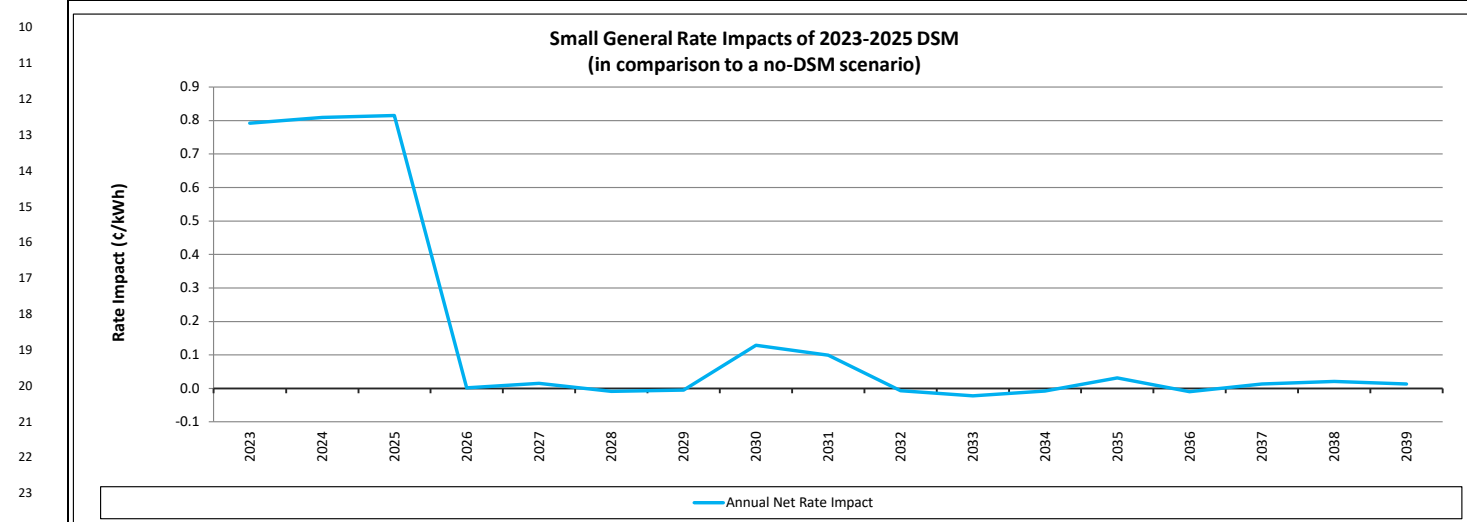
Attachment 3: Results by Rate Class (Alternate Scenario)

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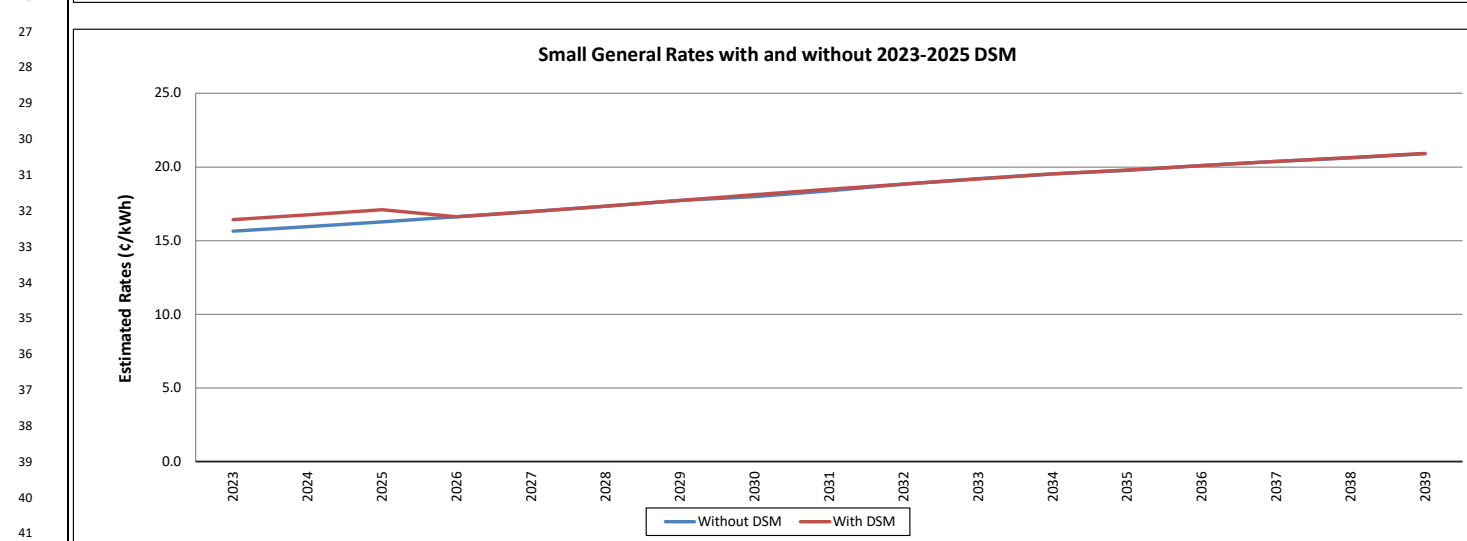


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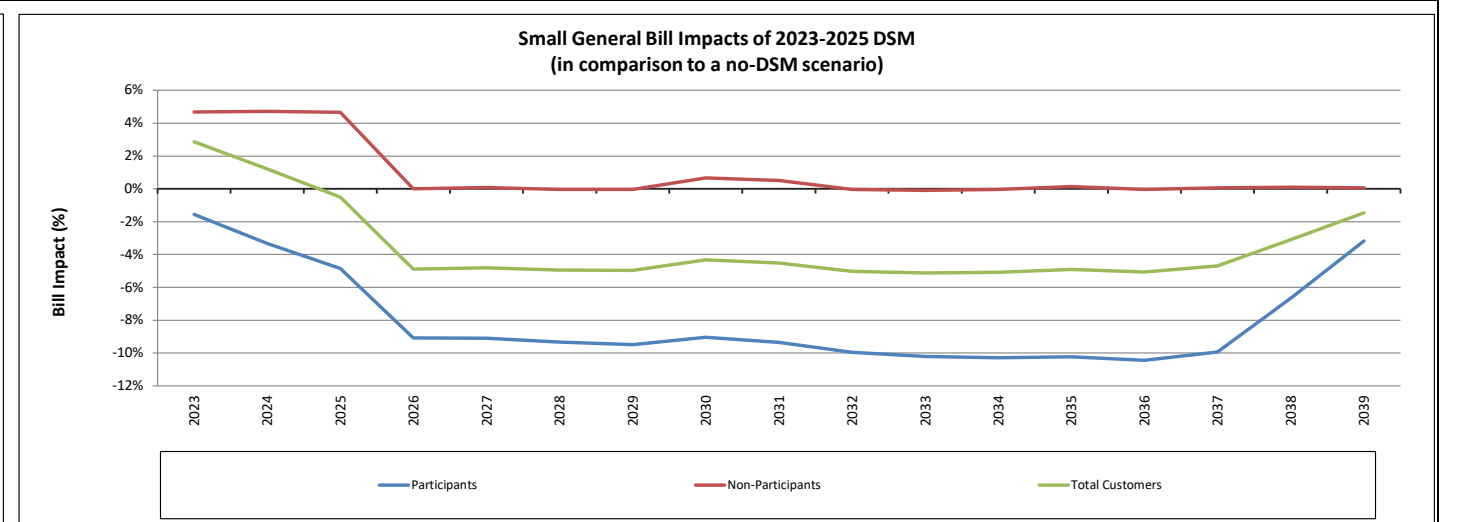
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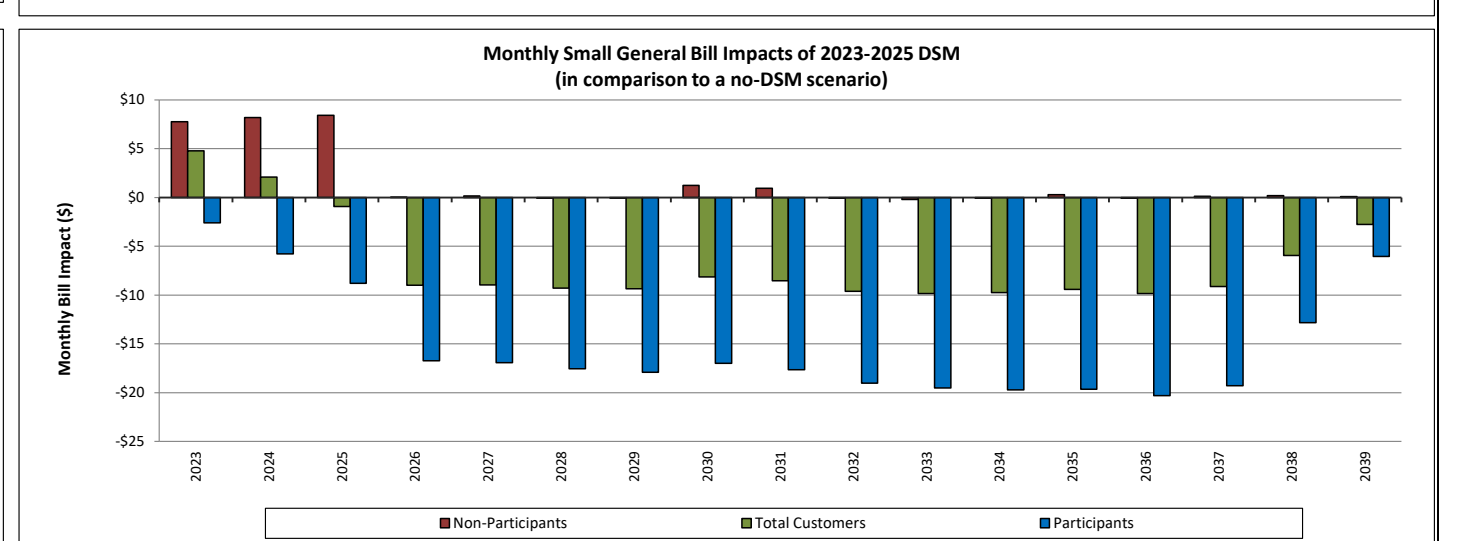
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25	This graph shows estimated rate impacts of DSM, relative to the no-DSM scenario.
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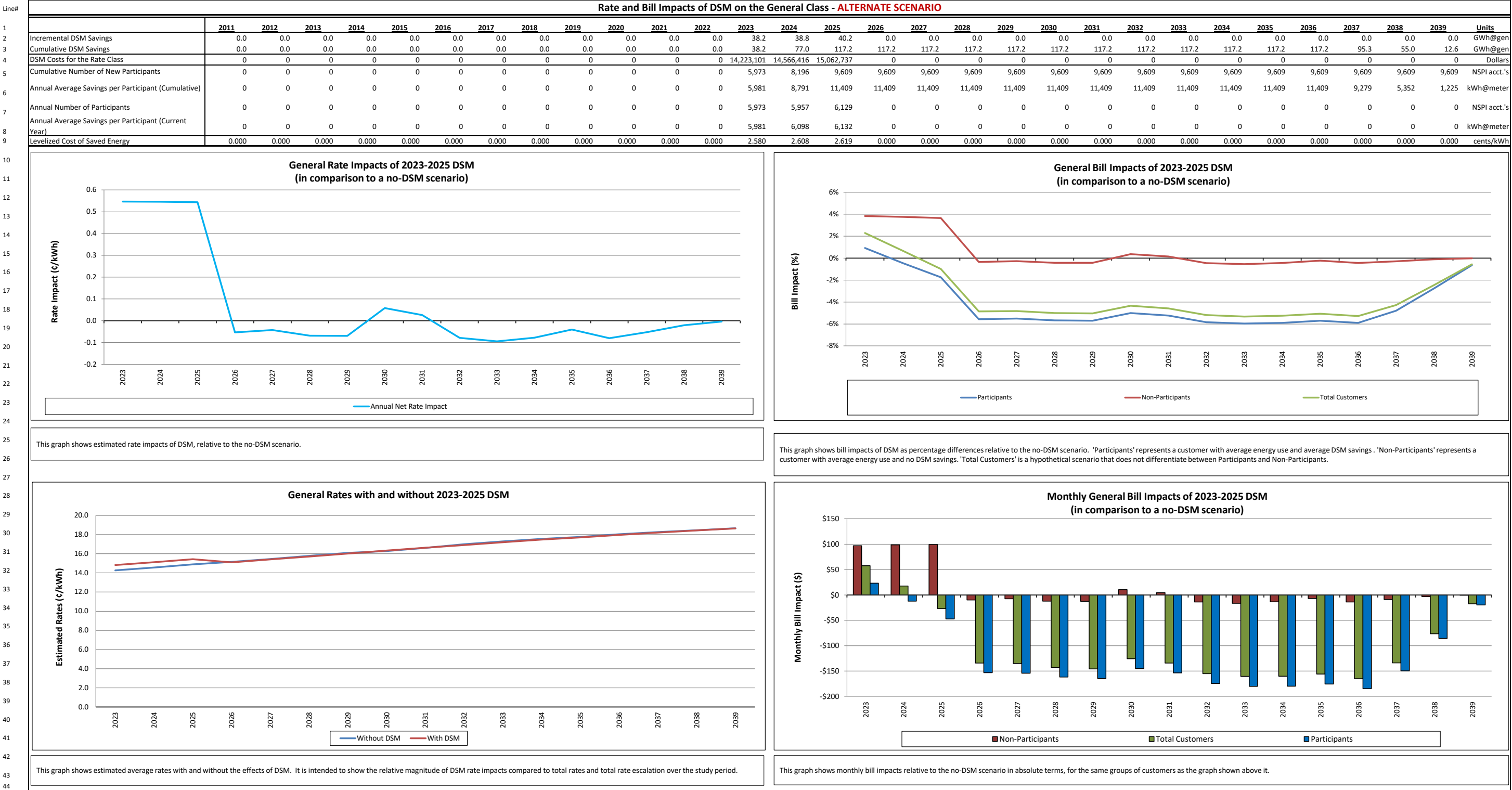
This graph shows estimated average rates with and without the effects of DSM. It is intended to show the relative magnitude of DSM rate impacts compared to total rates and total rate escalation over the study period.



This graph shows bill impacts of DSM as percentage differences relative to the no-DSM scenario. 'Participants' represents a customer with average energy use and average DSM savings. 'Non-Participants' represents a customer with average energy use and no DSM savings. 'Total Customers' is a hypothetical scenario that does not differentiate between Participants and Non-Participants.



This graph shows monthly bill impacts relative to the no-DSM scenario in absolute terms, for the same groups of customers as the graph shown above it.



	Rate and Bill Impacts of DSM on the General Class - ALTERNATE SCENARIO																																																														
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Units																																
	Incremental DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.2	38.8	40.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	GWWh@gen																																
	Cumulative DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.2	77.0	117.2	117.2	117.2	117.2	117.2	117.2	117.2	117.2	117.2	117.2	117.2	95.3	55.0	12.6	GWWh@gen																																
	DSM Costs for the Rate Class	0	0	0	0	0	0	0	0	0	0	0	0	0	14,223,101	14,566,416	15,062,737	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Dollars																															
	Cumulative Number of New Participants	0	0	0	0	0	0	0	0	0	0	0	0	0	5,973	8,196	9,609	9,609	9,609	9,609	9,609	9,609	9,609	9,609	9,609	9,609	9,609	9,609	9,609	9,609	NSPI acct.'s																																
	Annual Average Savings per Participant (Cumulative)	0	0	0	0	0	0	0	0	0	0	0	0	0	5,981	8,791	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	11,409	9,279	5,352	1,225	kWh@meter																																
	Annual Number of Participants	0	0	0	0	0	0	0	0	0	0	0	0	0	5,973	5,957	6,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	NSPI acct.'s																															
	Annual Average Savings per Participant (Current Year)	0	0	0	0	0	0	0	0	0	0	0	0	0	5,981	6,098	6,132	0	0	0	0	0	0	0	0	0	0	0	0	0	0	kWh@meter																															
	Levelized Cost of Saved Energy	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.580	2.608	2.619	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	cents/kWh																															
Cumulative General Participation Rates by Program																																Cumulative Participation as a Percentage of Total General Customers																															
This graph shows cumulative program participation for the class, as a percentage of eligible participants for each program. Each participant is counted once for each program, in the first year that they participate in the program. Darker bars show "tracked" participants (i.e. programs that collect participant info); lighter bars show "untracked" participants (i.e. programs that do not collect participation info, where participant figures are estimated).																																This graph shows cumulative program participation for the class, as a percentage of total customers in the class. Each participant is counted once, in the first that year they participate.																															
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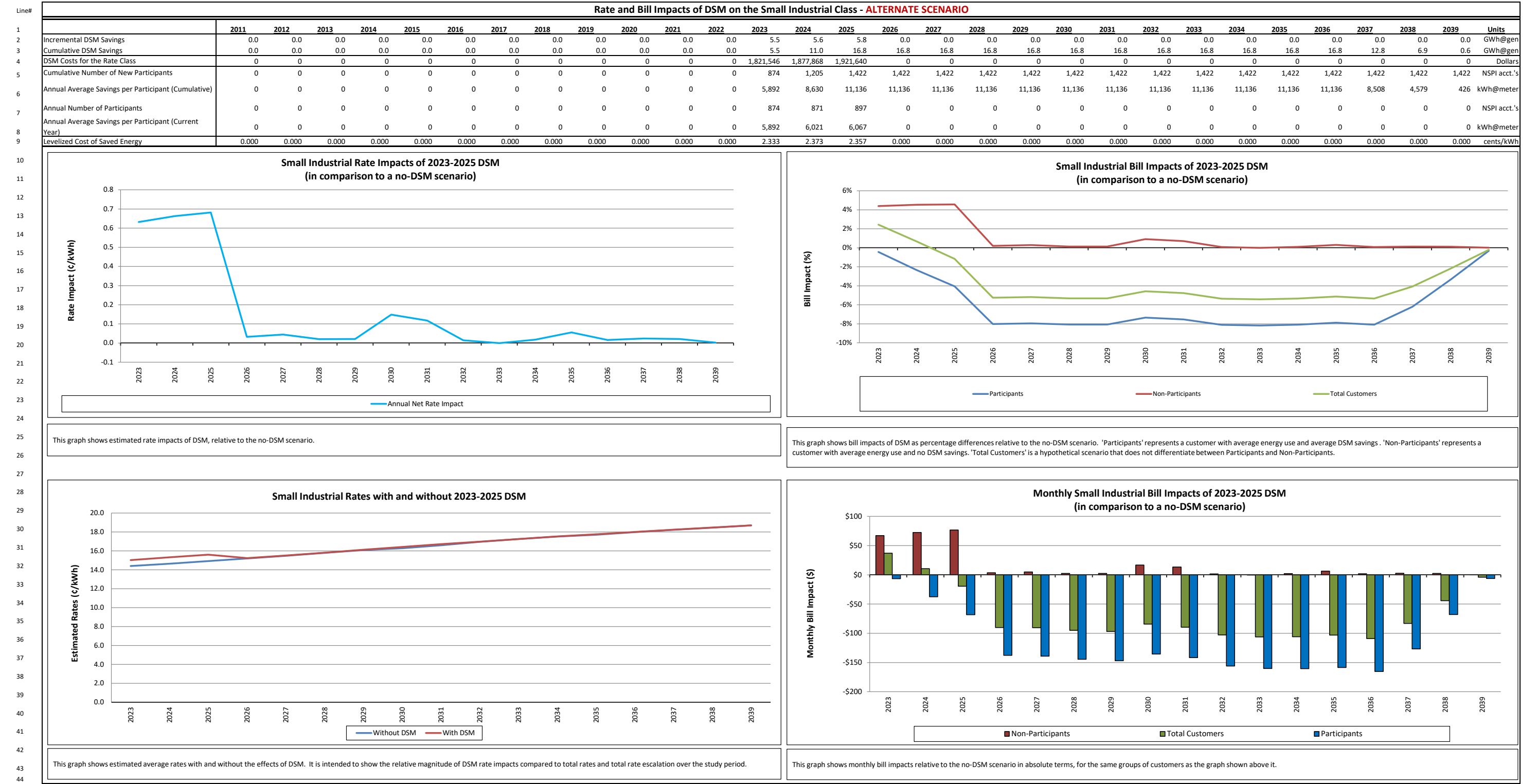
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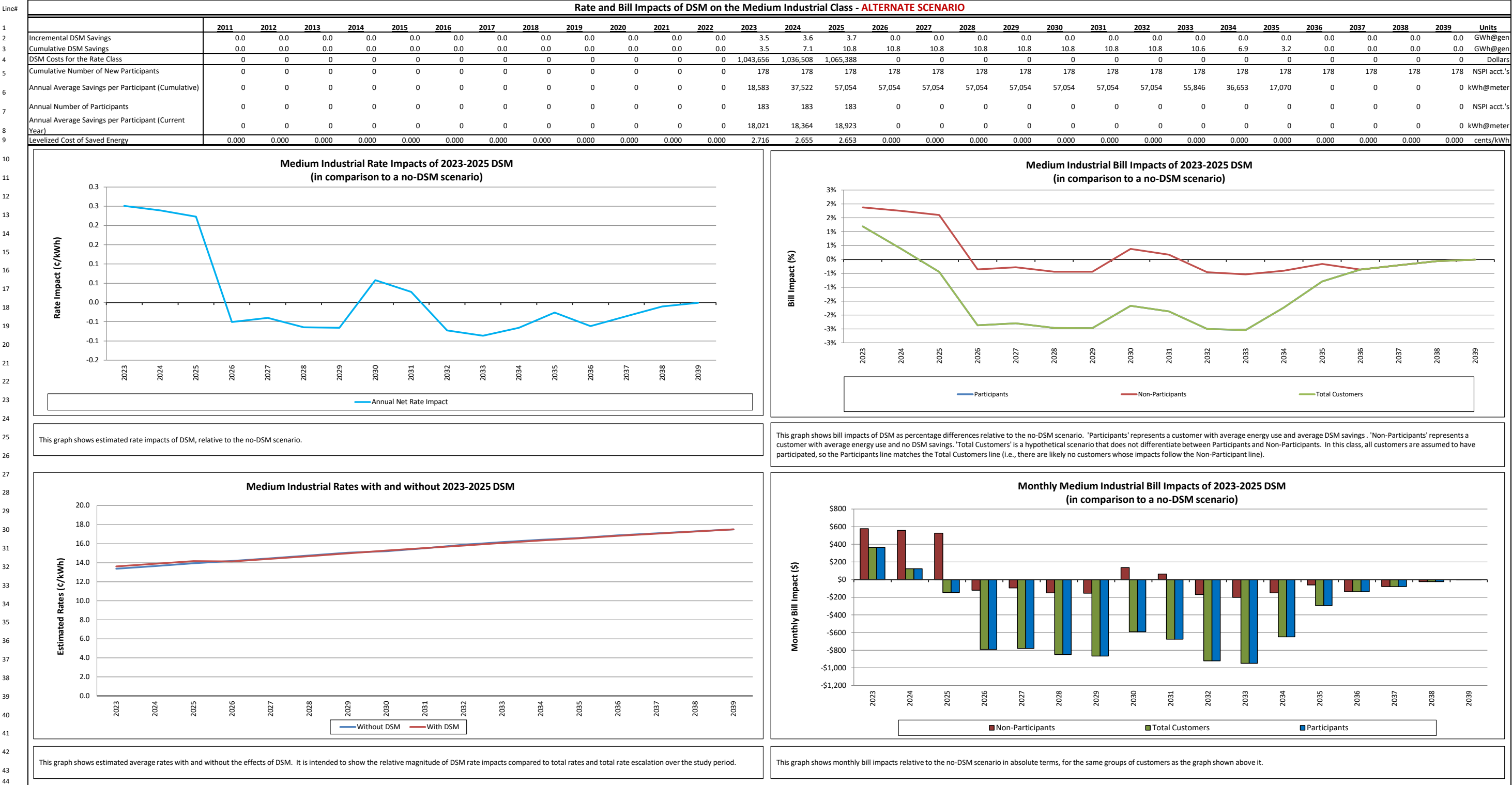
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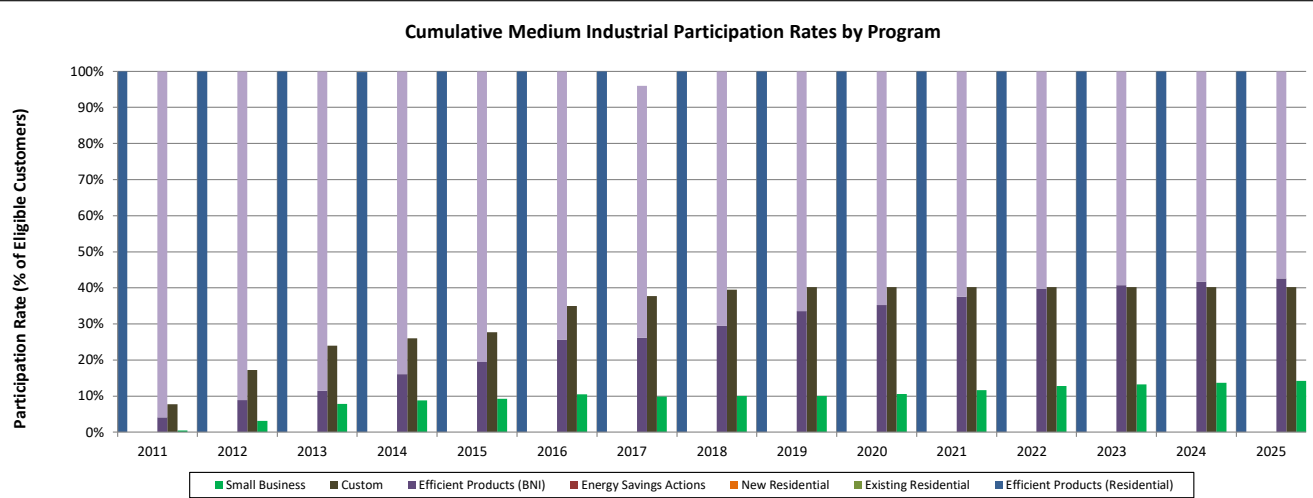
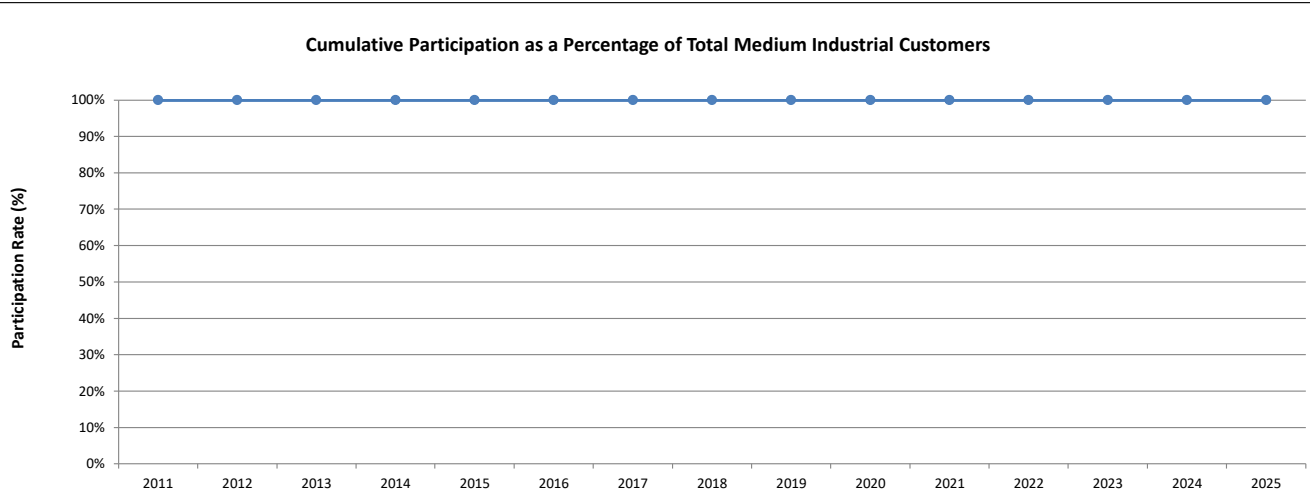
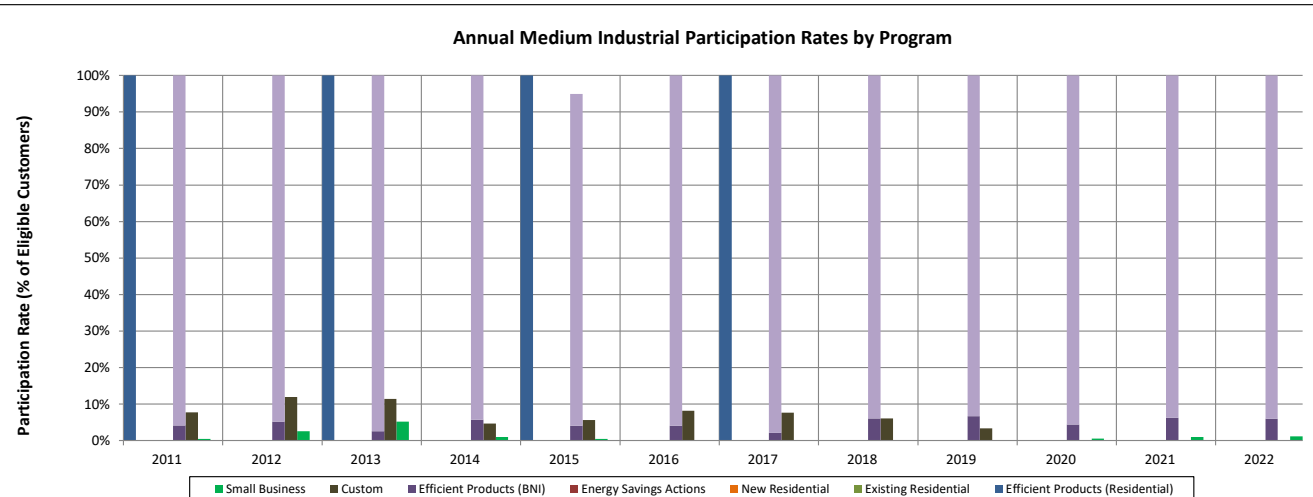
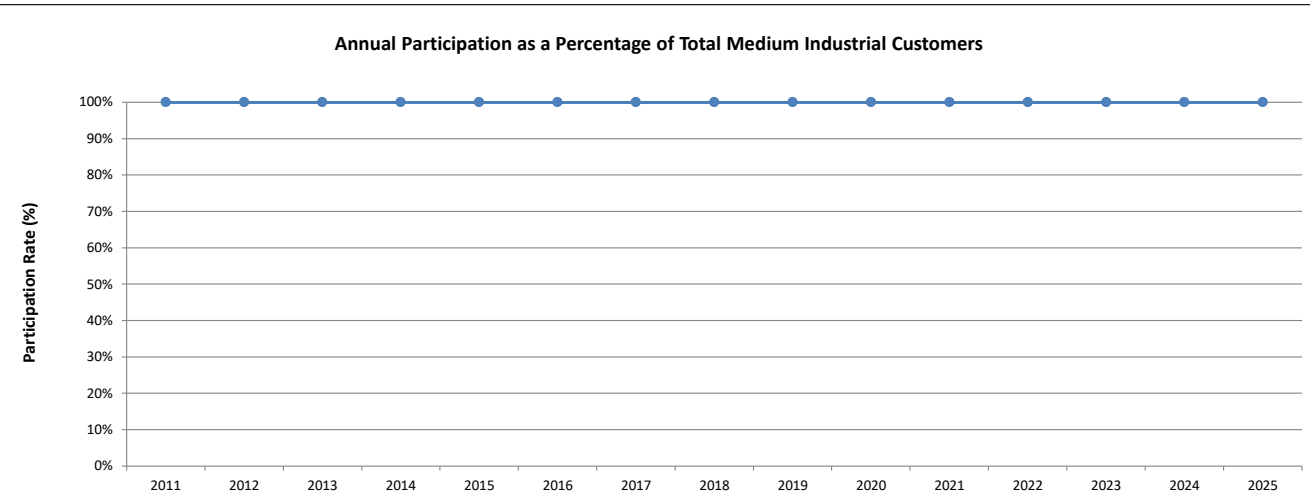
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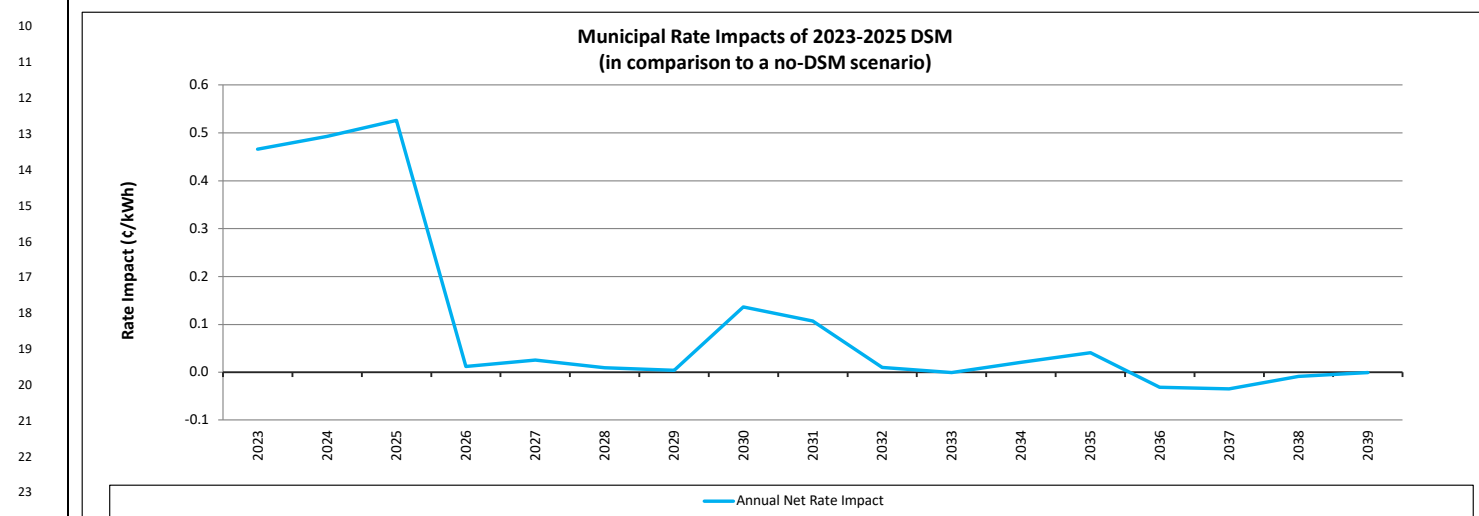




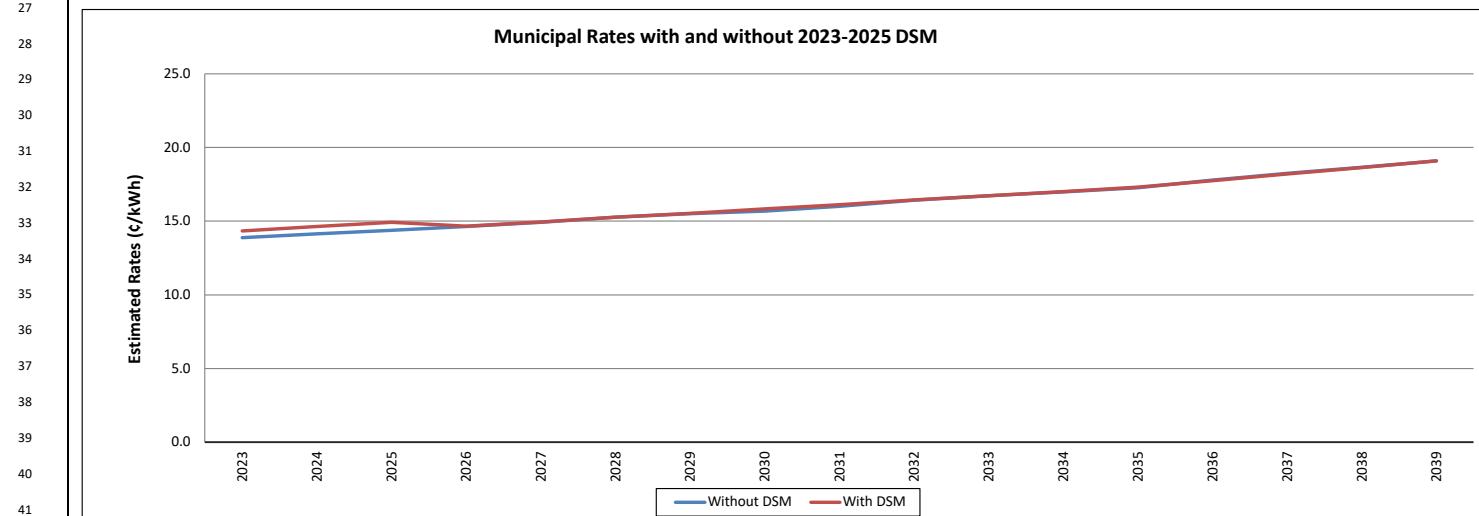
Line#	Rate and Bill Impacts of DSM on the Medium Industrial Class - ALTERNATE SCENARIO																														
1		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Units
2	Incremental DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	3.6	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	GWh@gen
3	Cumulative DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	7.1	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.6	6.9	3.2	0.0	0.0	0.0	0.0	GWh@gen
4	DSM Costs for the Rate Class	0	0	0	0	0	0	0	0	0	0	0	0	1,043,656	1,036,508	1,065,388	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Dollars
5	Cumulative Number of New Participants	0	0	0	0	0	0	0	0	0	0	0	0	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	NSPI acct.'s
6	Annual Average Savings per Participant (Cumulative)	0	0	0	0	0	0	0	0	0	0	0	0	18,583	37,522	57,054	57,054	57,054	57,054	57,054	57,054	57,054	57,054	55,846	36,653	17,070	0	0	0	0	kWh@meter
7	Annual Number of Participants	0	0	0	0	0	0	0	0	0	0	0	0	183	183	183	0	0	0	0	0	0	0	0	0	0	0	0	0	0	NSPI acct.'s
8	Annual Average Savings per Participant (Current Year)	0	0	0	0	0	0	0	0	0	0	0	0	18,021	18,364	18,923	0	0	0	0	0	0	0	0	0	0	0	0	0	0	kWh@meter
9	Levelized Cost of Saved Energy	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.716	2.655	2.653	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	cents/kWh
10	Cumulative Medium Industrial Participation Rates by Program 																														
11	Cumulative Participation as a Percentage of Total Medium Industrial Customers 																														
25	This graph shows cumulative program participation for the class, as a percentage of eligible participants for each program. Each participant is counted once for each program, in the first year that they participate in the program. Darker bars show "tracked" participants (i.e. programs that collect participant info); lighter bars show "untracked" participants (i.e. programs that do not collect participation info, where participant figures are estimated).																														
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28	Annual Medium Industrial Participation Rates by Program 																														
29	Annual Participation as a Percentage of Total Medium Industrial Customers 																														
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44																															



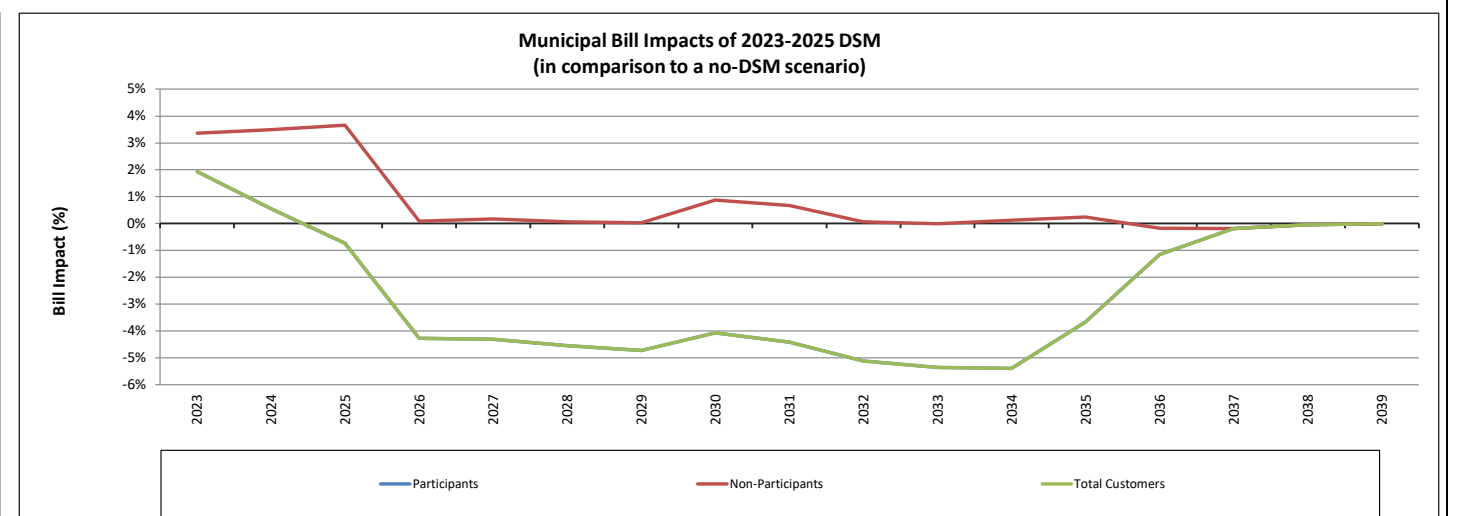
Line#	Rate and Bill Impacts of DSM on the Large Industrial Class - ALTERNATE SCENARIO																															
1		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Units	
2	Incremental DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.6	7.9	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	GWh@gen	
3	Cumulative DSM Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.6	15.4	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	19.0	9.6	0.1	0.0	0.0	0.0	0.0	0.0	GWh@gen
4	DSM Costs for the Rate Class	0	0	0	0	0	0	0	0	0	0	0	0	2,499,457	2,563,791	2,701,316	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Dollars
5	Cumulative Number of New Participants	0	0	0	0	0	0	0	0	0	0	0	0	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	NSPI acct.'s	
6	Annual Average Savings per Participant (Cumulative)	0	0	0	0	0	0	0	0	0	0	0	0	205,922	419,969	645,179	645,179	645,179	645,179	645,179	645,179	645,179	645,179	517,924	261,792	2,900	0	0	0	0	kWh@meter	
7	Annual Number of Participants	0	0	0	0	0	0	0	0	0	0	0	0	39	39	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	NSPI acct.'s	
8	Annual Average Savings per Participant (Current Year)	0	0	0	0	0	0	0	0	0	0	0	0	183,989	191,113	200,402	0	0	0	0	0	0	0	0	0	0	0	0	0	0	kWh@meter	
9	Levelized Cost of Saved Energy	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.186	3.209	3.265	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	cents/kWh	
10	Cumulative Large Industrial Participation Rates by Program Cumulative Participation as a Percentage of Total Large Industrial Customers																															
25	This graph shows cumulative program participation for the class, as a percentage of eligible participants for each program. Each participant is counted once for each program, in the first year that they participate in the program. Darker bars show "tracked" participants (i.e. programs that collect participant info); lighter bars show "untracked" participants (i.e. programs that do not collect participation info, where participant figures are estimated). This graph shows cumulative program participation for the class, as a percentage of total customers in the class. Each participant is counted once, in the first that year they participate.																															
28	Annual Large Industrial Participation Rates by Program Annual Participation as a Percentage of Total Large Industrial Customers																															
42	This graph shows annual program participation for the class, as a percentage of eligible participants for each program. Each participant is counted once in each year that they participate. Darker bars show "tracked" participants (i.e. programs that collect participant info); lighter bars show "untracked" participants (i.e. programs that do not collect participation info, where participant figures are estimated). This graph shows annual program participation for the class, as a percentage of total customers in the class. Each customer is counted once for each year that they participate in any program.																															

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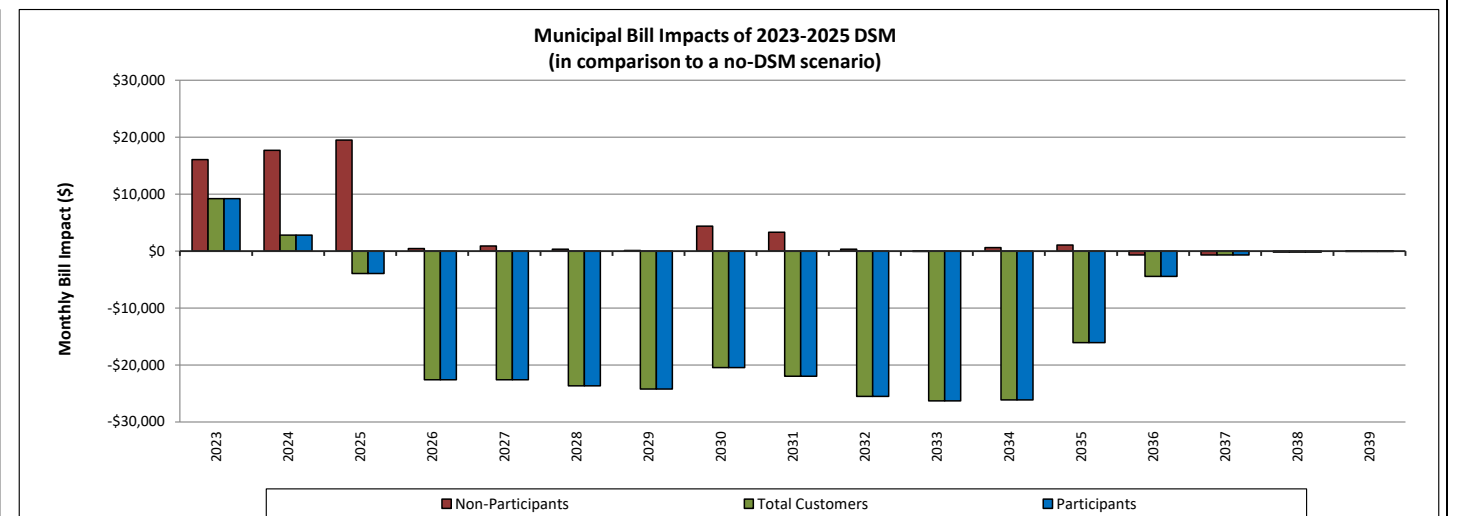
This graph shows estimated rate impacts of DSM, relative to the no-DSM scenario.



This graph shows estimated average rates with and without the effects of DSM. It is intended to show the relative magnitude of DSM rate impacts compared to total rates and total rate escalation over the study period.



This graph shows bill impacts of DSM as percentage differences relative to the no-DSM scenario. 'Participants' represents a customer with average energy use and average DSM savings. 'Non-Participants' represents a customer with average energy use and no DSM savings. 'Total Customers' is a hypothetical scenario that does not differentiate between Participants and Non-Participants. In this class, all customers are assumed to have participated, so the Participants line matches the Total Customers line (i.e., there are likely no customers whose impacts follow the Non-Participant line).



This graph shows monthly bill impacts relative to the no-DSM scenario in absolute terms, for the same groups of customers as the graph shown above it.

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Appendix B

Attachment 4: Assumptions

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This document is intended to provide an overview of the assumptions used in EfficiencyOne's (E1) 2023-2025 Demand Side Management (DSM) Plan Rate and Bill Impact Analysis (RBIA).

1. GENERAL APPROACH

E1 has used the "snapshot" approach recommended by Synapse, in which the impacts of specific program years are analyzed (in this case 2023-2025 programs) rather than incorporating an assessment of DSM over the long term.

2. SCENARIOS

Two separate models were created for this Plan: a Settlement Plan model and an Alternate Scenario model. Each model compares two scenarios: a DSM scenario and a no-DSM scenario. The DSM scenario in each model includes the costs and benefits of DSM programs that are planned to run throughout 2023-2025, and the no-DSM scenario does not include these DSM costs or benefits.

3. RATE CLASSES INCLUDED

Synapse has indicated that providing results for a few representative rate classes is sufficient to meet the intent of the rate and bill impact analysis. E1 has gone beyond this minimum to provide impacts for the following classes:

- Residential (rate codes 2, 3, 4, 5, 6, 9, and 16);
- Small General (rate code 10);
- General (rate code 11);
- Large General (rate code 12);
- Small Industrial (rate code 21);
- Medium Industrial (rate code 22);
- Large Industrial (rate codes 23 and 25, and customers under the 'one part high voltage real time pricing' tariff); and
- Municipal (rate code 24).

The Unmetered, Generation Replacement and Load Following (GRLF), Shore Power, and Extra Large Industrial Active Demand Control (ELIADC) rate classes are not included in the analysis. E1 does not offer programs for the GRLF, Shore Power, and ELIADC classes.

4. ENERGY AND DEMAND SAVINGS BY CLASS

For 2023-2025, first-year energy, lifetime energy, and demand savings developed at the program component level were allocated to rate classes in proportion with the actual rate class allocation of energy and demand results for each program component in 2020. One exception was the Custom program component where the 2020 allocations were not representative of what would be expected in the future and, therefore, a four-year average (2017-2020) rate class allocation was used for Custom only. Program component savings were added together within each rate class, within each year. Weighted-average measure lives (WAMLs) for each rate class were then developed based on the ratio of expected lifetime energy savings to expected first-year energy saving for each class.

Demand response (DR) costs, savings, measure life, and customer incentives are calculated and provided separately in the model from energy efficiency inputs. Demand response inputs are determined separately from energy efficiency to allow multiple scenarios to be produced, including:

- No DSM – no energy efficiency or demand response
- Energy Efficiency – without demand response
- Demand Response – without energy efficiency

Demand response inputs come from Guidehouse's DRSim™ model results. Where customer classes in the DRSim model do not match NS Power's rate classes, demand savings and costs were allocated to NS Power rate classes based on the class's peak load contribution. For example, the customer class "Large Industrial" in the DRSim™ model includes the NS Power rate classes Medium Industrial and Large Industrial (Firm). Savings and costs for this customer class are assigned 77% to Medium Industrial and 23% Large Industrial (Firm), based on Guidehouse's analysis of peak load contribution.

5. PARTICIPATION COUNTS BY CLASS

Participation estimates used in the RBIA model are different than participation estimates used in development of DSM plans, since the RBIA tracks participating NS Power accounts, rather than the number

of products sold, or installed, and also de-duplicates these accounts across programs and across years to produce estimates of the number of unique accounts that are expected to participate.

Annual participation rates for 2011-2020 were tracked by E1, and then resolved with customer records from previous years to determine cumulative counts of unique participants. This historical participation remains in the model so long-term participation trends can be observed. At the time the model was prepared, actual 2021 participation figures were not yet available.

Participant counts for 2021-2025 were estimated by multiplying 2020 participant counts by two factors: one to account for differences in overall program magnitude, and one to account for differences in the program measure mix relative to 2020. The first factor is the ratio of program component-level energy savings between each year from 2021-2025 and 2020; this factor assumes that the number of participating NS Power accounts will vary in proportion with the program energy savings. The second factor is the ratio of the number of rebated products per GWh of energy savings between 2021-2025 and 2020; this factor assumes that the number of participating NS Power accounts will also vary in proportion with the number of products rebated.

Participation values for 2011-2022 are the same as those filed in the revised 2021 Historical RBIA, filed 20 January 2022.

5.1 DEMAND RESPONSE PARTICIPATION

Demand response participation inputs come from Guidehouse's DRSim™ model. Customer classes in the DRSim™ model were attributed to NS Power rate classes based on NS Power class customer counts. The demand response participation represents the total number of active demand response participants in any given year. If a customer participated in demand response in 2023, 2024, and 2025, they would be counted once in each of those years. Demand response is assumed to have a measure life of one year so there is no cumulation of demand response participants.

In the DSM scenario, where the effects of energy efficiency and demand response together are examined, the rate class participation is assumed to be the greater of the total demand response or energy efficiency

participation. This is a reasonable assumption given E1 does not yet have historical data on cross-participation of energy efficiency and demand response programs.

5.2 POINT-OF-SALE PROGRAM COMPONENT PARTICIPATION COUNTS

All forecasted 2021-2025 participation, inclusive of point-of-sale program participation, was estimated based on 2020 results, using the methodology described above. Participation values for 2011-2021 are the same as those filed in the revised 2021 Historical RBIA, filed 20 January 2022. The 2011-2020 figures for point-of-sale program participation were estimated using the following methodology:

In estimating participation rates for point-of-sale discount program components, E1 assumes a value for re-participation rates (customers who participate in a point-of-sale program in more than one year) and for cross-participation rates (customers who participate in both a point-of-sale program and another program in the same year) for each of two point-of-sale programs, in each year. In the calculation of cumulative participation rates, E1 has applied both the re-participation rate and cross-participation rate for rate class totals, but only the re-participation rate for point-of-sale program totals. In the calculation of annual participation rates, E1 has applied only the cross-participation rate for rate class totals, and neither the re-participation rate nor cross-participation rate for point-of-sale program totals.

Annual participation by program within rate class

$$= (\#\_accounts) * (participation\_rate)$$

Annual participation by rate class

$$= (\#\_accounts) * (participation\_rate) * (1 - \text{cross-participation rate})$$

Cumulative participation by program within rate class

$$= (\#\_accounts) * (participation\_rate) * (1 - \text{re-participation rate})$$

Cumulative participation by rate class

$$= (\#\_accounts) * (participation\_rate) * (1 - \text{cross-participation rate}) * (1 - \text{re-participation rate})$$

Residential Instant Savings Assumptions:

- Assume that all customers are purchasing items for Residential use (i.e. that all customers are in the Residential and Municipal rate classes).

-
- To determine the number of participants in Instant Savings each year, E1 used information from primary research studies. The studies indicated that participation levels were 6% in 2011 and 2012, 7% in 2013, 13% in 2014, 37% in 2015, 25% in 2016, the study was not conducted in 2017 (25% was reused), 28% in 2018, 25% in 2019, and the study was not conducted in 2020 (25% was reused).
 - In early years, it was assumed that historical re-participation of customers each year is 10%. This assumption was based on an initial proposal from Rhode Island's 2013 rate and bill assumptions. Efficiency Nova Scotia Corporation (ENSC) reduced the number of unique participants by 10% in the first year of duplication (2012) and in 2013 accounted for 10% duplication in the remaining population. In 2014, ENSC engaged Corporate Research Associates to determine the number of re-participants in their quarterly omnibus survey. Of those who purchased products in 2014, 71% also purchased products in 2013. The study was not conducted in 2015-2017, so re-participation was assumed to remain at 71% for these years. In 2018, 48% of participants had also participated in previous years. In 2019, 72% of participants were found to have participated in previous years; this value was re-used in 2020.
 - Assume that participation in Instant Savings does not affect the probability that a customer will participate in another DSM program (i.e., estimate the cross-participation rate by dividing the number of tracked Residential rate class program participants by the total number of customers in the class).
 - For the Municipal Utility class, assume that each municipal utility participates in every year.

Business, Non-Profit and Institutional Business Energy Rebates – Instant Rebates (BER-IR) Assumptions:

- For high-consumption rate classes (Large General, Medium Industrial, Large Industrial, and Municipal), assume that each account participates in every year.
- For low-consumption rate classes (Small General, General, Small Industrial), research was conducted in 2016 to determine current and historical participation. To assist with recall over such a long time period, respondents were asked to group their memory of participation within the 2011-2014 period instead of providing answers for each of those four years.
 - For Small General, participation was 46% over 2011-2014, and 39% in 2015 and 2016. For General, it was 73% over 2011-2014, 62% in 2015 and 68% in 2016. For Small Industrial, it was 55% over 2011-2014, 50% in 2015 and 52% in 2016.

- For Small General, re-participation was 75% in 2015 and 79% in 2016. For General, it was 92% in 2015 and 96% in 2016. For Small Industrial, it was 88% in 2015 and 92% in 2016.
- For Small General, cross-participation was 13% in 2016. For General and Small Industrial it was 15% in 2016. Cross-participation was not researched for previous years, so these rates were applied to each year in the 2011-2015 period.
- The research was not conducted in 2017-2020, so all 2016 values were reused.
- As research indicated the total number of unique participants over the 2011-2014 period, but not the distribution of participants in each year therein (which this method requires), these annual figures must be calculated. They were estimated using a shape factor based on total program activity (# transactions that included rebates) in each year, and an assumption that the re-participation rate grows linearly between 2012 and 2014 (there is no re-participation in 2011). Using these two assumptions, the total 2011-2014 participant figures were allocated to each year in the 2011-2014 period – more participants in years with higher program activity and fewer participants in years with lower program activity, with the sum total over 2011-2014 held constant to the values obtained from research.
- A small number of BER-IR participants are assumed to come from the Residential class. Their rates of re-participation and cross-participation are assumed to match those determined for the Small General class.

5.3 ENERGY SAVINGS ACTIONS (HOME ENERGY REPORT) PARTICIPATION

Customers receiving the Home Energy Report were modelled as new participants in 2013. The same cross-participation rates used for Residential Instant Savings are used for the Home Energy Report, based on the assumption that participation in this program does not affect the probability that a customer will participate in another DSM program (i.e. estimate the cross-participation rate by dividing the number of tracked annual Residential rate class program participants by the total number of customers in the class). The Home Energy Report program formally ended in 2015, however, some participants continued to access the web portal until it was shut down in 2016.

5.4 LED HOLIDAY LIGHT EXCHANGE

E1 does not have participation records for the discontinued LED Holiday Light Exchange, so participants in this program component are not included in the analysis.

6. ENERGY AND DEMAND RATES

NS Power provided estimates for 2011-2022 of rates by class (including energy, demand, and customer charges). Beyond 2022, energy and demand charges are assumed to escalate at 2.0% per year, while customer charges are assumed to remain flat.

Prior to 2020, the RBIA model calculated energy and demand impacts separately, although only energy rate impacts were included in the output results. The results reflected energy rate impacts and total bill impacts, but demand rate impacts were left out. NS Power's rate model developed in 2020 provides results for a blended energy and demand rate in the form of \$/kWh; all rate effects are assigned to this blended rate.

In the current RBIA model, E1 has excluded demand charges from the bill savings calculations because these revenue requirements are already incorporated into the blended energy and demand rate provided by NS Power. The blended rate uses the assumption that demand and energy are saved at an equal rate (if a customer saves 15 percent on their consumption, this equates to both 15 percent reduction in energy and demand). In reality, the ratio of energy and demand savings will vary. This simplifying assumption may change the Participant and Non-Participant bill impacts slightly, but the Total Customer bill impacts will stay the same because ultimately the average monthly bills are equal to the class specific revenue requirements divided by customers in each scenario.

7. ENERGY AND DEMAND SALES

NS Power has provided historical and projected energy and demand sales within each rate class for 2011-2040. Energy sales are provided at the customer's meter for both the with DSM and without DSM scenario. Average monthly demand forecast is provided for the with DSM scenario.

8. AVOIDED COSTS

Avoided costs are calculated at the system level using evaluated DSM savings and avoided cost rates in four categories: generation, transmission, distribution, and energy. In addition, avoided cost of carbon was used for the purposes of a 'With Carbon' sensitivity analysis.

1 Table 1: Full Range of Avoided Cost Values Used for This Analysis

Category	Years	Details
Capacity (\$/kW-year)	2023-2040	Fitted series PRM adjusted stream (AVC 2.0C NPV 2023) of avoided costs of capacity, as calculated by NS Power for the IRP Reference Plan (Scenario 2.0C) and provided to the DSMAG on 20 August 2021.
Transmission (\$/kW-year)	2023-2040	23.2 \$/kW-year in 2021 - System-wide avoided costs of transmission as calculated by NS Power for 2021. 2% inflation applied for all other years to produce a stream of annual values.
Distribution (\$/kW-year)	2023-2040	20.2 \$/kW-year in 2021 - System-wide avoided costs of distribution as calculated by NS Power for 2021. 2% inflation applied for all other years to produce a stream of annual values.
Energy (\$/MWh)	2023-2040	Actual annual AVC energy stream (AVC 2.0C NPV 2023) of avoided costs of energy, as calculated by NS Power for the IRP Reference Plan (Scenario 2.0C) and provided to the DSMAG on 20 August 2021.
Carbon (\$/MWh)	2023-2040	- Based on the Federal trajectory of the cost of carbon, starting at \$30 per tonne in 2020, and escalating to \$170/tonne in 2030, and escalating by 2% annual inflation beyond 2030. - The price of carbon (\$/tonne) is multiplied by NS Power's emissions intensity for Base DSM savings (tonne/MWh), established using the Difference In Carbon Emissions (DICE) method for the IRP Reference Plan (Scenario 2.0C), to result in a \$/MWh avoided cost of carbon.

9. ELIGIBLE PARTICIPANTS

As part of the RBIA, overall participation and participation rates for each rate class are presented. In order to calculate this result, E1 has used the number of NS Power customer accounts in each rate class as the overall potential market. Because some customers have multiple account numbers, the total number of available accounts may be greater than the actual number of customers in a rate class. To determine the number of eligible participants for each DSM program, E1 determined the percentage of customers in the rate class to whom the program was being marketed. This assumption was made based on feedback from the DSM Advisory Group on 4 February 2015.

The only exception to using the number of accounts per rate class is for the Municipal Utility rate class. NS Power currently has five utility customers but seven accounts, because the Antigonish Electric Utility has three accounts. E1 does not track which Antigonish account is being served through particular programs or participants, so the rate and bill impacts include the number of customers (five) rather than the number of accounts (seven) for the Municipal Utility rate class only. Furthermore, NS Power is forecasting that as of

2023 there will be only one Municipal Electric Utility. Within the model this is handled by using an adjustment which normalizes the DSM savings to one customer so that the rate and bill impacts are representative on a per customer basis.

10. CALCULATION OF RATE IMPACTS

Rate impacts are calculated in NS Power's Rate Model and used as inputs within E1's RBIA model.

Forecast Unit Revenue (¢/kWh) is made up of the following components (presented in the 'NSP Input' tab):

- Forecast Unit Revenue Before DSM Program Costs and Customer Charge (¢/kWh) with and without DSM
- Forecast Unit DSM Program Charge (¢/kWh) (with DSM only)

All rate effects are assumed to apply to energy rates. Customer charges and demand charges remain the same in the with and without DSM scenarios.

11. CALCULATION OF BILL IMPACTS

Bill impacts are calculated in three categories: Participants, Non-Participants, and Total Customers.

Non-Participants are assumed to use the same amount of energy in the DSM scenario as they do in the no-DSM scenario. Their bills are only affected by changes in rates.

Participants consume less energy in the DSM scenario than in the no-DSM scenario. In each year, total cumulative savings are divided by total cumulative participants and subtracted from the average customer's no-DSM energy consumption to determine consumption for participants. Their bills are affected by changes in consumption as well as changes in rates.

Total Customers is a view of class impacts that does not differentiate between Participants and Non-Participants and provides a clear view of overall class rate and bill effects.

Appendix B

Attachment 5: NS Power Pricing Methodology

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Methodology for determination of changes in NS Power's base cost rates as a result of DSM-induced changes in class usage and total system costs

November 27, 2020

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Attachment A

Overview of Spreadsheet Calculations

1.0. Introduction

In an effort to more precisely and accurately align EfficiencyOne's (E1) RBIA Model with the methodological process used by NS Power in setting of its base cost rates, all rate setting functionality from E1's RBIA model has been removed and NS Power, instead, will perform this function in alignment with NS Power's COSS methodology. Under the new approach NS Power is responsible for providing inputs to E1 annually for use in the RBIA per a schedule agreed upon between E1 and NS Power. NS Power will provide the following annual inputs into E1's RBIA model over the entire historic DSM program effect horizon from 2011 to 2035 under the "With DSM" and "No DSM" scenarios:

- Forecast Unit Revenues Before DSM costs (¢/kWh)
- Forecast Unit DSM Program Charges (¢/kWh)
- Sales Forecast at Customer's meter (GWh)
- Average Monthly Demand Forecast (MW)
- Customer Count

NS Power will take responsibility for the cost allocation method, any assumptions used and the data inputs.

2.0. Background

The regulated base cost rate setting process involves the following three sequential analytical steps:

- Determination of total annual revenue requirement;
- COSS concerned with apportionment of total costs among rate classes; and
- Determination of class rates and class revenue responsibilities.

Revenue Requirement

Ordinarily, the base cost rate setting process used in rate case applications requires a great amount of detailed cost inputs to determine revenue requirement. Annual rate base data needs to be collected on a variety of investments such as plant-in-service, construction work in progress (CWIP), reserve for depreciation, working capital allowances, deferred charges, deferred credits, contract receivables, revenues, and operating expenses, to determine utilization of rate base by rate classes for the purpose of estimating cost allocation coefficients. Then the revenue requirement, or total system costs, need to be determined by collecting information on maintenance expenses, grants in lieu of taxes, depreciation, interest, corporate taxes and approved return on investment.

A detailed rate setting analysis, replicating efforts in the General Rate Application (GRA)-based rate applications, for a long-term, multi-year period would be a formidable task. Fortunately, such a detailed analysis is not necessary.

Since the purpose of the RBIA is to provide a long-term study on directional and relative (percent) changes in rates and bills due to only one factor – the DSM Program – it is sufficient to capture in revenue requirement only future changes due to DSM-induced avoided costs keeping all other costs constant.

Cost of Service Studies

COSS provides the most insight into class cost causation as based on changes in its energy and demand usage. It shows in a transparent way how rate class usage of demand and energy services within each functional area of generation, transmission and distribution affects its total responsibility for total the cost of service. To show relative changes in class rates due to DSM, it is important to accurately capture changes in system and class usage of demand and energy. This task can be easily accomplished as NS Power annually files a detailed ten-year Load Forecast Report with the UARB which already reflects the effect of DSM. Further, E1 prepares each year a forecast of long-term changes in class usage due to the implemented DSM programs. The purpose of directional changes in pricing of electric services can, therefore, be accomplished by a simplified COSS analysis which bypasses collection of future detailed annual investment and cost data inputs.

Rates and Revenues

There is little that can be inferred about the cost causation process from the rate structures used by the utility to generate customers' bills. The rates are bundled and therefore do not allow tracking of cost recovery by functional areas of generation, transmission and distribution. Further, NS Power's rates have only two components: an energy charge and a customer charge or an energy charge and a demand charge. Rates for residential and small general classes do not include demand charges. The demand-related costs of these two classes are recovered through energy charges. All other rate classes do not have customer charges. Their customer-related costs are recovered through a combination of demand and energy charges. Further, for rate classes with customer charges there is no alignment between customer-related revenues and customer-related costs and

for rate classes with demand charges there is no alignment between demand charge revenues and demand-related costs from COSS.

Conclusions

Bypassing the detailed COSS ratemaking step, which is intended to show how DSM-induced, cost causative changes in usage affects rates will produce misleading results and create difficulties in interpretation. Any such rate analyses by necessity must be of a marginal nature attempting to illustrate how decremental (lost) avoided costs compare to decremental revenues. This approach, even if enhanced by application of COSS-based allocation coefficients in attributing avoided costs and lost revenues to rate classes, fails to show how reallocation of the remaining embedded system costs among rate classes, due to changes in their usage, affects their rates.

A simplified COSS process will produce more precise results. It will also demonstrate how changes in class usage of energy and demand services within each functional area affects the total cost of service, providing more insight into why class total costs change as a result of DSM.

3.0. Applied Approach

The relative changes in rates due to DSM are determined by conducting two separate rate setting analyses under the “With DSM” and “No DSM” scenarios. The rate setting process under each scenario is broken out by two separate subprocesses: one for the determination of the FAM-related costs, and the other for the non-FAM-related costs.

3.1 Revenue Requirement

The annual revenue requirements under the “With DSM” scenario are kept consistent with the test year information from the preceding rate cases. The non-FAM costs in the years following the 2014 test year from the 2013 Rate Case are kept constant up to 2022, the last year of the current Rate Stability Plan (RSP). Thereafter, they are increased at an annual rate of inflation.

The FAM-related costs in years 2011 to 2022 are set to reflect test year costs set in the GRA or Base Cost of Fuel (BCF) FAM proceedings. Thereafter, they are modified for the marginal effect of change in annual load from the test year 2022 by adding a change in load multiplied by avoided fuel costs projected for a given year, as provided by E1. Also, the fuel costs in years after 2022 are subject to adjustment for annual inflation.

The annual revenue requirements for the recovery under the “No DSM” scenario are determined by modifying the FAM-cost and non-FAM cost requirements from the “With DSM” case, broken out by the three functional areas, for the incremental load effect due to the absence of DSM. The product of the incremental load effect and annual avoided unit costs is added to the annual revenue requirement from the “With DSM” case in all years from 2011 to 2035.

The applied process is based on test year revenue requirements which formed an input into prospective cost of service studies in past rate proceedings. Historic cost true-ups under the FAM are not taken into consideration for the following reasons:

- In the DSM-induced relative rate change study the annual cost true-ups do not have a material effect. The average difference in relative percentage change in rates due to DSM over 2011-2035 falls within hundredths of one percent while annual rate results are within a small fraction of one percent¹.
- The true-up for non-FAM costs (excess non-FAM revenues) lacks the rigour and details of COSS analysis.
- Inclusion of true-up costs would make the calculations unnecessarily more complex for the directional purposes of this RBIA study.

3.2 Cost of Service Studies

Cost of service Studies consist of an application of the following three sequential steps:

- functionalization of revenue requirement to the four areas: generation, transmission, distribution and retail;
- classification of costs within each area among energy, demand and customer; and
- Apportionment of costs within each service of each functional area among rate classes.

Most of the service costs are shared by all customers and are apportioned to rate classes in accordance with their utilization of utility resources. The only costs which are not shared in NS Power's COSS are streetlight fixture costs, all of which are assigned to street and area light customers billed under the unmetered class.

3.2.1 Functionalization of System Costs

As indicated in the Revenue Requirement section above, NS Power has used the test year revenue requirements, already functionalized by the four areas, from the historic rate cases. In the "With DSM" case, the FAM-related revenue requirements falling outside the 2011-2022 period have been subject to adjustment for the effect of change in annual load from the 2022 benchmark year by adding a product of a change in load and avoided unit fuel costs projected for a given year. The total system non-FAM costs in that period are not modified for the changes in annual load because its overall trend is flat and, as such, would not trigger any capacity expansion investment. Both the FAM and Non-FAM costs are increased for the rate of inflation starting in 2023.

¹ For example, consider the effect of true-up for the return of the Maritime Link depreciation costs of about \$100 million in years 2017-2019 on the relative change in the total service cost under the "With DSM" and "No DSM scenarios" over 2011-2035 period.

Without true-up for \$100 million: $\$35,697.6 \text{ million} / \$37,569 \text{ million} - 1 = - 4.98\%$

With true-up for \$100 million: $(\$35,697.6 - \$100) \text{ million} / (\$37,569 - \$100) \text{ million} - 1 = - 4.99 \%$

In the “No DSM” case the annual revenue requirements represent the annual FAM and non-FAM revenue requirements from the “With DSM” case modified for the effect of change in load due to absence of DSM. The load savings in each area due to DSM are multiplied by projected avoided unit costs and added to the revenue requirements from the “With DSM” case.

3.2.2 Classification of System Costs

Costs within each area are classified into appropriate services. Generation and transmission costs are classified into energy and demand. Distribution costs are classified between demand and customer. Retail costs are all classified to customer.

Both in the “With DSM” and “No DSM” cases costs are reclassified into appropriate services in accordance with changes in system usage.

Generation costs are classified between energy and demand depending on the function performed by various generation units. Baseload generation units, which reflect most of the investment in this area, have most of their investment reclassified from demand to energy based on system load factor. Peaking units, such as combustion turbines, are classified only to demand while environmental investments, designed to reduce air emissions, are classified only to energy. A significant portion of non-dispatchable generation is also directly classified to energy. Absent detailed information on how changes in the total generation investment due to DSM affects the overall classification of generation costs, NS Power has used the following linear equation, with the coefficient determined through application of the least squares technique to simulated 2014 COSS data, to estimate the classification of generation costs for the RBIA purposes.

$$\text{Asset Weighted Average Load Factor} = 17.98\% + 0.8060 * \% \text{ System Load Factor.}$$

Transmission costs are appropriately classified to demand and energy in accordance with the system load factor in each year.

As far as the distribution costs are concerned, only demand-related costs are subject to change. The customer-related costs remain static except for the effect of inflation because DSM does not have an effect on changes in the number of customers. Likewise, retail costs are kept static except for changes for rate of inflation.

3.2.3 Allocation of Costs to Rate Classes

Annual cost requirements within each service of each functional area are apportioned to rate classes based on class share in the underlying usage both in the “With DSM” and “No DSM” case.

FAM-related Costs

The FAM-related costs are allocated to rate classes using the following two-step process:

- Annual class energy usage is multiplied by the benchmark unit cost \$/MWh

- o In the “With DSM” case the benchmark unit costs come from the most recent rate case preceding this year.
 - o In the “No DSM” case the benchmark unit costs come from the same year as the “With DSM” case.
- The class annual costs estimated above are then scaled across the board to match annual FAM revenue requirement.

As a result, the relative FAM-related unit costs in years falling outside the 2011-2022 rate period are the same as in 2022. The above process does not account explicitly for the FAM cost differentiation by energy- and demand-related services as is the case with allocation of non-FAM costs discussed below. This is done this way because NS Power’s model was developed a few years ago when FAM demand-related costs accounted for a very small share of the total FAM costs and as a result, capturing the distinction between energy and demand was not material. Recently the share of the demand-related costs grew to a more significant level of 15 percent of the FAM total due to inclusion of the Maritime Link Costs. This aspect of cost allocation can be remodeled in future RBIA applications.

Non-FAM related Costs

The non-FAM-related costs are allocated to rate classes using the following two-step process:

- Annual class usages of energy and demand services are multiplied by benchmark \$/MWh and \$/MW unit costs, respectively
 - o In the “With DSM” case the benchmark unit costs come from the most recent rate case preceding this year.
 - o In the “No DSM” case the benchmark unit costs come from the same calendar year from the “With DSM” case.
- The class annual costs estimated above are then scaled across the board to match the revenue requirement set for each service within each functional area.

DSM Costs

The annual DSM-related costs incurred by individual rate classes, as provided by E1, are apportioned to rate classes based on the 25/75 rule.

75 percent of the costs incurred by each class is treated as direct responsibility of each class.

The remaining 25 percent of total annual DSM costs is apportioned to all rate classes based on their energy and demand usage. These costs are first classified to energy and demand based on system annual load factor. The energy-related costs are then assigned to rate classes based on their

share in the total annual system generation. The demand-related costs are assigned to rate classes based on their share in the three winter month coincident system peaks.

3.2.4 Generic COSS Results

The actual results from the above cost allocation process under the “With DSM” and “No DSM” scenarios are presented in the “COSS Outputs” tab within NS Power’s rate model, where the long-term trends in annual relative unit cost of service differential by rate class between the “No DSM” and “With DSM” scenarios are graphically portrayed.

Generically speaking, each class long-term trend can be broken down by two distinct periods.

- Historic budget period typified by higher increases in unit costs due to inclusion of DSM program cost recovery as well as growing cumulative effect of ramping up DSM measures undertaken in previous years.
- Out year period with
 - lower unit cost differential due to exclusion of DSM Program cost recovery and
 - gradually declining unit cost of service differentials due to ramping down effect of expiring DSM measures undertaken in the historic budget periods.

The diversity in individual class results in the historic budget periods is attributable to differences in both DSM spend on rate classes and changes in class unit costs due to changes in their relative usage on the basis of which costs of services are apportioned to rate classes.

The diversity in individual class results in the out year period is only attributable to differences in changes in class usage on the basis of which costs of services are apportioned to rate classes.

In general, classes whose total cost of service bear a relatively higher share of fuel costs, such as the Large Industrial, Municipal, Medium Industrial and Large General, see higher reduction rate benefits due to the DSM-induced reduction in system costs because more of the utility cost savings come from the reduced fuel consumption than lower utilization of its fixed cost infrastructure. The opposite holds true for rate classes with higher responsibility for the fixed infrastructure costs such as the Domestic and Small General classes.

3.3 Unit Revenue Determination

For the directional purposes of the RBIA model, it is not considered necessary to develop annual rates with all charges under the “With DSM” and “No DSM” cases. Rather, it is sufficient for NS Power to provide class unit blended revenues, separate from the DSM charges, in cent per kWh, without customer charge revenue for the Residential and Small General rate classes, and with all costs in, other than DSM, for all other rate classes. These unit revenues have been determined as unit costs adjusted for annual line losses for each class.

The above approach ignores the effect on class unit revenues of the following factors:

- Annual true-up of fuel and non-fuel costs flown through the FAM AA/BA Riders;
- Deferral of certain costs in revenue requirement which have not been removed from the filed COSS Compliance Filing;
- Smoothing of Rates under multi-year rate plans; and
- Revenue-to-cost ratios which are used to determine class revenue responsibilities.

Exclusion of the above factors has no material effect on the relative changes in unit revenues between the “With DSM” and “No DSM” cases.

Attachment A

Overview of Spreadsheet Calculations

Data Inputs

“COSS Data Inputs” tab

This tab includes all annual test year class usage and embedded costs from the COSS and BCF COSS filed in GRA and BCF proceedings as well as a forecast of annual usage by class per the most recent ten-year Load Forecast Report. It also includes annual DSM Expenditures on rate classes. All the above data is used in determination of class unit costs and revenues.

“E1 Data Inputs” tab

This tab includes information provided to NS Power by E1 on DSM Program measures and avoided unit costs, all of which are used in determination of class unit costs and revenues.

Savings in energy and demand usage by rate class

Savings in energy and demand usage arising from DSM programs for each class are tracked in the following class tabs: R-Savings, SG-Savings, G-Savings, LG-savings, SI-Savings, MI-Savings, LI-Savings, M-Savings, UNM-Savings.

For each class, annual usage savings at the generator’s gate are determined by adding projected annual usage savings effects of DSM Programs undertaken for each class in specific calendar year in the period 2011 to 2022. This computation is the same as used by E1 in support of its RBIA Reports.

Total annual Energy and Demand changes at the generator’s gate are converted to energy sales and demands at customers’ meters by netting out energy and demand losses. The energy and demand losses used in these calculations come from the COSS on public record.

Changes in total Revenue Requirement

“Total-Savings” tab

The “Total-Savings” tab provides a sum of annual class savings in energy and demand usage at the generator’s gate and customer’s meter. In addition, class demand savings at the high side of the bulk power substation are also calculated for each class.

The total energy savings at the generator’s gate are used to determine total avoided fuel costs.

The total demand savings at the generator’s gate are used to determine total avoided costs of generation and transmission infrastructure.

The total demand savings at the high side of the bulk power substation are used to determine total avoided costs of distribution infrastructure.

The FAM-related avoided costs are determined by multiplying unit avoided fuel costs (\$/MWh) by system energy savings (MWh) in each year. This is appropriate as under the FAM customers pay the actual fuel costs incurred.

The non-FAM related avoided costs are determined by multiplying annual avoided costs of generation, transmission, and distribution (\$/MW) by total annual MW demand savings in these functional areas.

Cost of Service Studies

Apportionment of costs to rate classes is done separately for the “With DSM” and “No DSM” cases” in the tabs bearing the same names.

“With DSM” tab

The “With DSM” tab provides annual cost allocation to rate classes based on long-term usage as included in NS Power’s most recent Annual ten-year Load Forecast Report. This usage already reflects inclusion of DSM Program effects.

The FAM-related costs of each class are adjusted only in years 2023-2035 as they fall outside of the most recent rate setting period which ends in 2022. The following two-step process is used to calculate FAM class costs in this period:

- Annual FAM costs for each class are calculated by multiplying the forecast annual MWh usage by blended unit FAM costs in \$/MWh from 2022, the last year for which the FAM rates have been set on the regulatory record.
- The annual class FAM costs above are scaled across the board to match the total FAM costs calculated for a given calendar year.
- The total annual FAM costs in a given calendar year are calculated using the following formula:

$$\text{Annual FAM Cost} = (\text{Previous year FAM Cost}) + (\text{Delta in Energy Requirement from previous year}) * (\text{Unit Avoided FAM cost from the given year}).$$

Comments

The applied process is a simplification of a more elaborate cost allocation process from the COSS where some FAM costs, such as fuel costs, are allocated to rate classes based on their shares in monthly energy requirements; some other FAM costs, such as non-dispatchable energy-related renewable costs, are allocated based on class shares in annual energy requirements; and yet some other FAM costs are classified to demand, such as Maritime Link costs, are classified to Demand based on system load factor, and are allocated based on class shares in three coincident system peaks. To recognize the diversification in the class FAM unit costs, the relative class unit costs from the most recent rate setting procedure are carried forward to subsequent years’ cost

calculation simulation. For example, the relative class unit FAM costs from 2022 are carried over to years 2023 – 2035.

The total of non-FAM costs incurred on serving all rate classes within each functional area is assumed to be fixed between rate cases at a level from the most recent rate case. There is an option in the spreadsheet (cell E3, “COSS Outputs” tab) to increase non-FAM costs in future years (2023-2035) by an annual rate of inflation to approximate rate effects of future GRAs conducted once every several years. The individual class shares in these costs change annually based on changes in total service costs of energy and demand within generation and transmission as based on changes in system load factor.

The total service costs of energy and demand within each service can be adjusted for annual inflation effect in years 2023–2035.

“No DSM” tab

The “No DSM” tab provides annual cost allocation to rate classes absent DSM.

The FAM-related costs in years 2011–2035 are calculated using the following process:

- Annual FAM costs for each class are calculated by multiplying annual MWh usage (without DSM savings) by blended unit FAM costs in \$/MWh from the same year as the “With DSM” case. This calculation is in the table labelled “Before External Effect”.
- The annual class FAM costs above are scaled across the board to match the total FAM costs estimated for a given calendar year. This calculation is in the table labelled “After External Effect”.
- The total annual FAM costs in a given calendar year are calculated using the following formula:

$$\text{Annual FAM Cost} = (\text{FAM Cost from a given year under the “With DSM” case}) + (\text{Delta in Energy Requirement between the “With DSM” and “No DSM” case from a given year}) * \text{Unit Avoided FAM cost from the given year.}$$

This above calculation is in the “Total” column of the “After External Effect” table.

Comments

The applied process is a simplification of a more elaborate cost allocation process where some FAM costs, such as fuel costs, are allocated to rate classes based on their shares in monthly energy requirements; some other FAM costs, such as non-dispatchable energy-related renewable costs, are allocated based on class shares in annual energy requirements; and yet some other FAM costs are classified to demand and are allocated based on class shares in three coincident system peaks. To recognize the diversification in the class FAM unit costs, the relative class unit costs from the

most recent rate setting procedure are carried forward to subsequent year cost calculation simulation.

The non-FAM costs incurred on serving all rate classes in each year are determined as follows:

- The total annual non-FAM costs in each of the functional areas of generation, transmission and distribution in a given calendar year are calculated using the following formula:

Annual non-FAM Cost = (non-FAM Cost from a given year under the “With DSM” case) + avoided costs as estimated in “Total Savings” tab.

The above calculation is in the “Total” column of the “Fixed (functional area) - After Prorating” table.

- Annual non-FAM costs from each area, as estimated above, are split between the energy- and demand-related services based on the load factor derived from system usage in the no-DSM case. For generation, an estimate of asset-weighted load factor is used. It is determined as a function of a linear equation relating an asset-weighted load factor to a system load factor based on the most recent COSS. For transmission, a system load factor is used.
- Annual non-FAM costs for each class within each service and functional area (for example, demand-related generation cost) are calculated by multiplying annual MWh or MW usage (without DSM savings) by blended unit non-FAM costs in \$/MWh or \$/MW from the same year as the “With DSM” case. This calculation is in the table labelled “Fixed (functional area) Costs Streams by Rate classes - Before External Effect”.
- The annual class non-FAM costs above are scaled across the board to match the total FAM costs estimated for a given calendar year within each service in each functional area. This calculation is in the table labelled “Fixed (functional area) Costs Streams by Rate classes - After Prorating”.

The total service costs of energy and demand within each service costs can be adjusted for annual inflation effect in years 2023–2035.

The annual FAM and non-FAM costs above are added up to provide total annual cost for each class in a given year and then divided by energy requirement to provide annual unit cost at generator’s gate.

Comments

The applied process is a simplification of a more elaborate cost allocation process in the COSS where energy- and demand- related non-FAM costs, are determined through application of rate base usage allocators developed separately for various sub-categories of costs (please see exhibits 8A and 8B in the 2014 COSS). To recognize the diversification in the class non-FAM unit costs

the relative class unit costs from the COSS used in the most recent rate setting procedure are carried forward to subsequent year cost calculation simulation.

“COSS Var” tab

“COSS Var” provides differentials between cell values in the “No DSM” and “With DSM” tabs. Please note that the data layouts in the “No DSM” and “With DSM” tabs are identical with the exception for the treatment of DSM costs which in “No DSM” case are excluded.

Results

“COSS Outputs” tab

The “COSS Outputs” tab provides two sets of bar graphs of percentage change in class rates due to DSM over the period 2011–2035 calculated as either arithmetic or load-weighted rate changes. The graphs within each set are broken out by the following effects:

- Change in unit base cost revenues before accounting for the effect of DSM costs
- Change in unit base cost revenues under the “No DSM” scenarios by inclusions of DSM cost.
- Change in unit base cost revenues taking both the above effects into account

This tab also includes a control panel to test the effect of a change in:

- Rate of inflation and
- Avoided cost level (avoided cost scenarios)

on absolutes and relative changes in class unit costs and unit revenues.

“NSPI Inputs into RBIA” tab

“NSPI Inputs into RBIA” provides pricing inputs requested by E1. It includes the following annual class data in years 201-2035 broken out by “With DSM” and “No DSM” scenarios:

- Forecast Unit Revenues Before DSM costs (¢/kWh)
- Forecast Unit DSM Program Charges (¢/kWh)
- Sales Forecast at Customer’s meter (GWh)
- Average Monthly Demand Forecast (MW)
- Customer Count

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Appendix B

Attachment 6: NS Power Rate Model – Settlement Plan

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Appendix B

Attachment 7: NS Power Rate Model – Alternate Scenario

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Appendix B

Attachment 8: E1 RBIA Model – Settlement Plan

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Appendix B

Attachment 9: E1 RBIA Model – Alternate Scenario

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Appendix C

Alternate Scenario

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1. 2023-2025 ALTERNATE SCENARIO

Like the Settlement Plan, E1's key global assumptions and design objectives for the Alternate Scenario align with E1's DSM Plan Guiding Principles and the Standardized Filing Framework (SFF). With the Balanced Plan Approach and Balanced Portfolio framework in mind, the following design objectives were applied to both the Settlement Plan and Alternate Scenario:

- investment in low-income (LI): 17% to 22% of total energy efficiency portfolio investment;
- investment split: 50% Residential (Res) and 50% Business, Non-Profit & Institutional (BNI) programs; and
- energy savings split: 40% Res and 60% BNI programs.

The Alternate Scenario will invest \$160.1 million (in nominal dollars) to achieve 377.3 GWh of incremental cumulative net energy savings, 84.7 MW of cumulative system-peak demand savings (inclusive of both demand reductions of 76.4 MW, and demand response (DR) capacity additions of 8.3 MW), and 4,469 GWh of cumulative net lifetime energy savings at the generator. Figure 1, below, provides highlights of the Alternate Scenario.

1

Figure 1: 2023-2025 Alternate Scenario – Portfolio-level Insights

Carbon Emissions Avoided	
First-Year CO ₂ e Savings (kt)	299
Lifetime CO ₂ e Savings (kt)	1,658
Portfolio Summary (2023-2025)	
First-Year Energy Savings (GWh)	377.3
Peak Demand Savings (MW)	84.7
Investment (\$ million)	160.1
% of Plan Investment in Low-Income	18.5%
Energy & Demand Savings	
Lifetime Energy Savings (GWh)	4,469
Weighted Average Measure Life (yrs)	11.8
Energy Savings as % of NS Power Load	1.1%
DR as % of NS Power Peak Load ^a	0.5%
Energy Savings (EE) Split (RES/BNI)	41/59
Demand Savings (EE) Split (RES/BNI)	44/56
Demand Savings (DR) Split (RES/BNI)	35/65
% of Non-Lighting Energy Savings	68.4%
Energy Efficiency (EE) Investment	
EE Investment Split (RES/BNI) ^b	50/50
First-Year Unit Cost (\$/kWh)	0.41
Lifetime Unit Cost (\$/kWh)	0.035
Lifetime Benefits (\$ million) ^d	517
Net Benefits (\$ million) ^d	363
Demand Response (DR) Investment	
10 Year Levelized Cost (\$/kW-yr) ^c	214.68
Lifetime Benefits (\$ million) ^d	1
Net Benefits (\$ million) ^d	-5
DR Investment Split (RES/BNI) ^b	52/48

2

^a Percentage of NS Power peak load by 2025

3

^b Excluding Enabling Strategies investment

4

^c Calculated by taking the net present value of costs and MWs for each DR pathway over the 2022-2031 timeframe; includes all E1 and NS Power costs

5

6

^d EE and DR net benefits are calculated based on the Program Administrator Cost (PAC). For EE, the lifetime benefits are counted and, for DR, the first three years (2023-2025). In DR, the Critical Peak Pricing (CPP) only includes smart thermostat related costs/benefits.

8

9

10 1.1 ALTERNATE SCENARIO – SAVINGS & INVESTMENT

11 Table 1 provides a summary of the energy savings, demand savings, and investment for the 2023-2025
 12 Alternate Scenario.

1 Table 1: 2023-2025 Alternate Scenario Investment and Savings

Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Weighted Average Measure Life (years)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
							incl. carbon	excl. carbon	incl. carbon	excl. carbon
51.1	167.3	114.1	1,459	12.8	26.2	1.5	2.0	1.4	3.1	2.2
53.2	172.2	130.2	1,483	11.4	24.9	4.8	2.0	1.4	3.1	2.2
55.9	179.1	133.0	1,527	11.5	25.2	8.3	2.0	1.4	3.1	2.2
160.1	518.6	377.3	4,469	11.8	76.4	8.3	2.0	1.4	3.1	2.2

2 Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may
3 not add correctly, due to rounding.

4 Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP
5 using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.
6 Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

7 ^a Investment for DR includes only E1's required investment for the Alternate Scenario. It is recognized that in order for DR
8 benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff
9 resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

10 ^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission,
11 distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the
12 avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of
13 benefits).

14 ^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs
15 and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes
16 only.

17 ^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to
18 include the expected full program life. PAC excluding carbon is provided for informational purposes only.

1 Table 2: 2023-2025 Alternate Scenario Investment and Savings, by Program Component

2023-2025	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
							incl. carbon	excl. carbon	incl. carbon	excl. carbon
Residential (Res) Energy Efficiency (EE) Programs										
Efficient Product Rebates	14.1	30.8	32.3	279.0	3.5	-	1.1	0.7	2.2	1.4
Appliance Retirement	3.1	2.0	3.7	15	0.5		0.9	0.6	0.6	0.4
Instant Savings	11.0	28.8	28.6	264	2.9		1.1	0.7	2.6	1.7
Existing Residential	55.6	143.0	121.0	1,107	28.6	-	1.5	1.1	2.6	1.9
Efficient Product Installation	5.8	11.1	19.6	93	3.4		1.9	1.3	1.9	1.3
Affordable Multi-family Housing	4.0	11.6	5.6	102	1.7		1.2	0.9	2.9	2.1
Home Energy Assessment	11.7	66.9	25.7	515	13.0		2.0	1.6	5.7	4.4
Green Heat	6.7	29.7	10.7	193	8.2		1.5	1.2	4.4	3.5
Mi'kmaw Home Energy Efficiency Project	3.7	3.3	1.6	30	0.5		0.9	0.6	0.9	0.6
Affordable Single-Family Homes	19.2	13.5	6.6	124	1.9		0.7	0.5	0.7	0.5
Residential Behaviour	4.5	7.0	51.1	51	0.0		1.5	0.8	1.5	0.8
New Residential	0.8	3.9	0.4	13	1.3	-	2.6	2.4	4.8	4.4
Low-Income Participation ^e	28.7	33.4	26.8	296	5.3		0.9	0.7	1.2	0.8
Res EE Programs Total	70.6	177.7	153.7	1,399	33.3	-	1.4	1.0	2.5	1.8
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs										
Efficient Product Rebates	22.1	167.5	104.8	1,560	19.8	-	3.7	2.5	7.6	5.1
Custom Incentives	26.2	110.0	80.0	948	15.2	-	2.5	1.7	4.2	2.8
Custom	22.4	107.0	69.5	925	14.3		2.6	1.8	4.8	3.2
Energy Management Information Systems	1.0	0.9	2.6	8	0.0		1.3	0.7	1.0	0.5
Strategic Energy Management	2.8	2.1	8.0	15	0.9		0.9	0.5	0.8	0.4
Direct Installation	21.1	62.0	38.7	562	8.0	-	2.2	1.5	2.9	2.0
Low-Income Participation ^e	0.6	4.7	2.9	43	0.8		2.8	1.9	7.6	5.2
BNI EE Programs Subtotal	69.4	339.5	223.6	3,070	43.0	-	2.9	2.0	4.9	3.3
Total EE Programs	140.0	517.2	377.3	4,469	76.4	-				
Enabling Strategies (ES)										
Education & Outreach	4.5									
Development & Research	5.8									
Other Enabling Strategies	4.2									
Total ES	14.5									
EE Portfolio Total (EE + ES)	154.5	517.2	377.3	4,469	76.4	-	2.0	1.4	3.3	2.3
Demand Response (DR) Program										
Residential Demand Response	2.9					2.9		0.7		0.6
BNI Demand Response	2.7					5.4		1.8		0.8
DR Program Total	5.6	1.4	-	-	-	8.3		1.0		0.7
DSM Portfolio Total (EE + ES + DR)	160.1	518.6	377.3	4,469	76.4	8.3	2.0	1.4	3.1	2.2

2 Currency is expressed in nominal dollars. Currency in the total row is a straight sum of 3 years of nominal values. Columns may
3 not add correctly, due to rounding.

4 Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP
5 using the Base level of DSM for Scenario 2.0C. Avoided costs of transmission and distribution were provided by NS Power in 2021.

6 Cost-effectiveness ratios in the total row are calculated using 2023 present values of each year's costs and lifetime benefits.

7 ^a Investment for DR includes only E1's required investment for the Alternate Scenario. It is recognized that in order for DR
8 benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff
9 resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

10 ^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission,
11 distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the
12 avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of
13 benefits).

14 ^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs
15 and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes
16 only.

17 ^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to
18 include the expected full program life. PAC excluding carbon is provided for informational purposes only.

20 Table 3, Table 4, and Table 5 provide the program investment budgets and targets for 2023, 2024 and 2025,
21 respectively.

1 Table 3: 2023 Alternate Scenario Investment and Savings, by Program Component

2023	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d	
							incl. carbon	excl. carbon	incl. carbon	excl. carbon
Residential (Res) Energy Efficiency (EE) Programs										
Efficient Product Rebates	4.0	9.1	10.9	83	1.2	-	1.1	0.7	2.3	1.4
Appliance Retirement	1.0	0.7	1.2	5	0.2		0.9	0.5	0.6	0.4
Instant Savings	2.9	8.4	9.7	78	1.0		1.2	0.7	2.9	1.8
Existing Residential	17.9	45.1	30.1	359	9.6	-	1.5	1.1	2.5	1.9
Efficient Product Installation	2.0	3.7	6.9	32	1.2		1.9	1.2	1.9	1.2
Affordable Multi-family Housing	1.3	3.8	1.9	34	0.6		1.2	0.9	2.9	2.0
Home Energy Assessment	3.9	21.7	8.6	172	4.3		2.0	1.5	5.6	4.2
Green Heat	2.2	9.6	3.6	64	2.7		1.5	1.2	4.3	3.4
Mi'kmaw Home Energy Efficiency Project	1.2	1.1	0.5	10	0.2		0.9	0.6	0.9	0.6
Affordable Single-Family Homes	6.3	4.4	2.2	41	0.6		0.7	0.5	0.7	0.5
Residential Behaviour	1.0	0.8	6.4	6	0.0		0.8	0.5	0.8	0.5
New Residential	0.8	3.9	0.4	13	1.3	-	2.6	2.4	4.8	4.4
Low-Income Participation ^e	9.4	10.8	7.9	98	1.8	-	0.9	0.7	1.2	0.8
Res EE Programs Subtotal	22.7	58.1	41.4	455	12.0	-	1.4	1.1	2.6	1.9
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs										
Efficient Product Rebates	7.3	54.4	34.6	515	6.5	-	3.7	2.5	7.5	5.0
Custom Incentives	8.5	35.0	25.6	307	5.0	-	2.5	1.7	4.1	2.8
Custom	7.3	34.1	22.3	300	4.7		2.6	1.8	4.7	3.1
Energy Management Information Systems	0.2	0.2	0.6	2	0.0		1.3	0.7	1.0	0.5
Strategic Energy Management	0.9	0.7	2.7	5	0.3		0.9	0.5	0.7	0.4
Direct Installation	6.8	19.7	12.5	182	2.6	-	2.2	1.5	2.9	1.9
Low-Income Participation ^e	0.2	1.5	1.0	14	0.3	-	2.7	1.8	7.5	5.0
BNI EE Programs Subtotal	22.6	109.1	72.7	1,004	14.2	-	2.9	2.0	4.8	3.2
Total EE Programs	45.3	167.2	114.1	1,459	26.2	-				
Enabling Strategies (ES)										
Education & Outreach	1.5									
Development & Research	1.8									
Other Enabling Strategies	1.2									
Total ES	4.5									
EE Portfolio Total (EE + ES)	49.8	167.2	114.1	1,459	26.2	-	2.0	1.4	3.4	2.3
Demand Response (DR) Program										
Residential Demand Response	0.4					0.1		0.7		0.6
BNI Demand Response	0.9					1.4		1.8		0.8
DR Program Total	1.3	0.1			-	1.5		1.0		0.7
DSM Portfolio Total (EE + ES + DR)	51.1	167.3	114.1	1,459	26.2	1.5	2.0	1.4	3.1	2.2

2 Currency is expressed in 2023 dollars. Columns may not add correctly, due to rounding.

3 Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP
4 using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.5 ^a Investment for DR includes only E1's required investment for the Alternate Scenario. It is recognized that in order for DR
6 benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff
7 resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.8 ^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission,
9 distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the
10 avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of
11 benefits).12 ^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs
13 and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes
14 only.15 ^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to
16 include the expected full program life. PAC excluding carbon is provided for informational purposes only.17 ^e Reflects E1's planned participation by low-income customers. Numbers are a subset of Residential Efficient Product Rebates,
18 Existing Residential, Efficient Product Rebates (BNI), and Direct Installation.

1 Table 4: 2024 Alternate Scenario Investment and Savings, by Program Component

2024	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d		
							incl. carbon	excl. carbon	incl. carbon	excl. carbon	
Residential (Res) Energy Efficiency (EE) Programs											
Efficient Product Rebates	4.6	10.1	10.4	91	1.1	-	1.1	0.7	2.2	1.4	
Appliance Retirement	1.0	0.7	1.2	5	0.2		0.9	0.6	0.6	0.4	
Instant Savings	3.5	9.4	9.2	86	1.0		1.1	0.7	2.7	1.7	
Existing Residential	18.8	48.7	45.6	374	9.5	-	1.5	1.1	2.6	1.9	
Efficient Product Installation	1.9	3.7	6.5	31	1.1		1.9	1.3	1.9	1.3	
Affordable Multi-family Housing	1.3	3.9	1.9	34	0.6		1.2	0.9	2.9	2.1	
Home Energy Assessment	3.9	22.4	8.6	172	4.3		2.0	1.6	5.7	4.4	
Green Heat	2.2	9.9	3.6	64	2.7		1.5	1.2	4.5	3.5	
Mi'kmaw Home Energy Efficiency Project	1.2	1.1	0.5	10	0.2		0.9	0.6	0.9	0.6	
Affordable Single-Family Homes	6.4	4.5	2.2	41	0.6		0.7	0.5	0.7	0.5	
Residential Behaviour	1.8	3.2	22.3	22	0.0		1.8	0.9	1.8	0.9	
New Residential	0.0	0.0	0.0	0	0.0	-	-	-	-	-	
Low-Income Participation ^e	9.6	11.3	9.5	99	1.8	-	1.0	0.7	1.2	0.8	
Res EE Programs Subtotal	23.4	58.8	56.1	465	10.7	-	1.4	1.0	2.5	1.8	
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs											
Efficient Product Rebates	7.3	55.5	34.6	515	6.5	-	3.7	2.5	7.6	5.1	
Custom Incentives	8.7	36.8	26.6	316	5.1	-	2.5	1.7	4.2	2.9	
Custom	7.5	35.8	23.1	308	4.8		2.6	1.8	4.8	3.2	
Energy Management Information Systems	0.3	0.3	0.9	3	0.0		1.3	0.7	1.0	0.5	
Strategic Energy Management	0.9	0.7	2.7	5	0.3		0.9	0.5	0.8	0.4	
Direct Installation	7.0	20.7	12.9	187	2.7	-	2.3	1.5	3.0	2.0	
Low-Income Participation ^e	0.2	1.6	1.0	14	0.3	-	2.8	1.9	7.6	5.2	
BNI EE Programs Subtotal	23.1	113.0	74.1	1,018	14.3	-	2.9	2.0	4.9	3.3	
Total EE Programs	46.5	171.8	130.2	1,483	24.9	-					
Enabling Strategies (ES)											
Education & Outreach	1.5										
Development & Research	2.0										
Other Enabling Strategies	1.5										
Total ES	5.0										
EE Portfolio Total (EE + ES)	51.5	171.8	130.2	1,483	24.9	-	2.0	1.4	3.3	2.3	
Demand Response (DR) Program											
Residential Demand Response	1.1					1.3		0.8		0.6	
BNI Demand Response	0.7					3.5		2.7		0.8	
DR Program Total	1.8	0.4	-	-	-	4.8		1.1		0.7	
DSM Portfolio Total (EE + ES + DR)	53.2	172.2	130.2	1,483	24.9	4.8	2.0	1.4	3.1	2.2	

2 Currency is expressed in 2024 dollars. Columns may not add correctly, due to rounding.

3 Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP
4 using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

5 ^a Investment for DR includes only E1's required investment for the Alternate Scenario. It is recognized that in order for DR
6 benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff
7 resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

8 ^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission,
9 distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the
10 avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of
11 benefits).

12 ^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs
13 and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes
14 only.

15 ^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to
16 include the expected full program life. PAC excluding carbon is provided for informational purposes only.

17 ^e Reflects E1's planned participation by low-income customers. Numbers are a subset of Residential Efficient Product Rebates,
18 Existing Residential, Efficient Product Rebates (BNI), and Direct Installation.

1 Table 5: 2025 Alternate Scenario Investment and Savings, by Program Component

2025	Investment ^a (\$ million)	Lifetime Benefits ^b (\$ million)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak EE Demand Savings (MW)	Available DR Capacity (MW)	Total Resource Cost Test (TRC) ^c		Program Administrator Cost Test (PAC) ^d		
							incl. carbon	excl. carbon	incl. carbon	excl. carbon	
Residential (Res) Energy Efficiency (EE) Programs											
Efficient Product Rebates	5.6	11.6	10.9	105	1.1	-	1.1	0.7	2.1	1.4	
Appliance Retirement	1.1	0.7	1.2	5	0.2		0.9	0.6	0.6	0.4	
Instant Savings	4.5	11.0	9.7	100	1.0		1.1	0.7	2.4	1.6	
Existing Residential	19.0	49.2	45.3	374	9.5	-	1.5	1.1	2.6	2.0	
Efficient Product Installation	1.9	3.6	6.2	30	1.1		1.9	1.3	1.9	1.3	
Affordable Multi-family Housing	1.4	3.9	1.9	34	0.6		1.2	0.9	2.9	2.1	
Home Energy Assessment	3.9	22.8	8.6	172	4.3		2.0	1.6	5.8	4.5	
Green Heat	2.2	10.2	3.6	64	2.7		1.5	1.2	4.5	3.7	
Mi'kmaw Home Energy Efficiency Project	1.3	1.1	0.5	10	0.2		0.9	0.6	0.9	0.6	
Affordable Single-Family Homes	6.5	4.6	2.2	41	0.6		0.7	0.5	0.7	0.5	
Residential Behaviour	1.8	3.0	22.3	22	0.0		1.7	0.9	1.7	0.9	
New Residential	0.0	0.0	0.0	0	0.0	-	-	-	-	-	
Low-Income Participation ^e	9.8	11.4	9.4	99	1.8	-	0.9	0.7	1.2	0.8	
Res EE Programs Total	24.5	60.8	56.2	478	10.6	-	1.4	1.0	2.5	1.8	
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs											
Efficient Product Rebates	7.5	57.7	35.6	531	6.7	-	3.7	2.6	7.7	5.3	
Custom Incentives	9.0	38.1	27.9	325	5.1	-	2.5	1.7	4.2	2.9	
Custom	7.7	37.1	24.2	317	4.8		2.6	1.8	4.8	3.3	
Energy Management Information Systems	0.4	0.4	1.1	3	0.0		1.2	0.7	0.9	0.6	
Strategic Energy Management	0.9	0.7	2.7	5	0.3		0.9	0.5	0.7	0.5	
Direct Installation	7.2	21.6	13.3	193	2.8	-	2.3	1.6	3.0	2.1	
Low-Income Participation ^e	0.2	1.6	1.0	15	0.3	-	2.8	1.9	7.7	5.4	
BNI EE Programs Subtotal	23.8	117.4	76.8	1,049	14.6	-	2.9	2.0	4.9	3.4	
Total EE Programs	48.3	178.2	133.0	1,527	25.2	-					
Enabling Strategies (ES)											
Education & Outreach	1.5										
Development & Research	2.0										
Other Enabling Strategies	1.5										
Total ES	5.0										
EE Portfolio Total (EE + ES)	53.3	178.2	133.0	1,527	25.2	-	2.0	1.4	3.3	2.4	
Demand Response (DR) Program											
Residential Demand Response	1.4					2.9		0.7		0.6	
BNI Demand Response	1.1					5.4		1.8		0.8	
DR Program Total	2.6	0.8	-	-	-	8.3		1.0		0.7	
DSM Portfolio Total (EE + ES + DR)	55.9	179.1	133.0	1,527	25.2	8.3	2.0	1.4	3.1	2.2	

2 Currency is expressed in 2025 dollars. Columns may not add correctly, due to rounding.

3 Annual avoided costs of energy and capacity and annual avoided CO₂e emissions were provided by NS Power, from the 2020 IRP
4 using the Base level of DSM. Avoided costs of transmission and distribution were provided by NS Power in 2021.

5 ^a Investment for DR includes only E1's required investment for the Alternate Scenario. It is recognized that in order for DR
6 benefits to be realized, NS Power collaboration and investment will also be required. This may include investment for staff
7 resource, event calling by the system operator, and Distributed Energy Resources Management System (DERMS) integration.

8 ^b Lifetime benefits for EE are expressed as the net present value of the avoided costs, including energy, capacity, transmission,
9 distribution, and carbon over the life of the program measures, using utility WACC. For DR, lifetime benefits are expressed as the
10 avoided costs, including capacity, transmission, and distribution, resulting from operating DR in 2023-2025 (three years of
11 benefits).

12 ^c TRC is a benefit/cost ratio comparing lifetime benefits to the sum of E1's and participants' costs. For DR, 10-year lifetime costs
13 and benefits are taken to include the expected full program life. TRC excluding carbon is provided for informational purposes
14 only.

15 ^d PAC is a benefit/cost ratio comparing lifetime benefits to E1's costs. For DR, 10-year lifetime costs and benefits are taken to
16 include the expected full program life. PAC excluding carbon is provided for informational purposes only.

17 ^e Reflects E1's planned participation by low-income customers. Numbers are a subset of Residential Efficient Product Rebates,
18 Existing Residential, Efficient Product Rebates (BNI), and Direct Installation.

1.2 ALTERNATE SCENARIO – RATE CLASS ALLOCATIONS

Planned rate class expenditures for the Alternate Scenario are provided in Table 6, below, by year and by Plan period.

Table 6: Rate Class Expenditures by Year

Rate Class	Alternate Scenario Expenditures (\$ million) by Rate Class			
	2023	2024	2025	2023-2025
Residential/Charitable (2,3,4)	25.5	27.1	28.6	81.2
Small General (10)	2.8	2.9	3.0	8.8
General Demand (11)	14.1	14.5	15.0	43.7
Large General (12)	2.3	2.2	2.5	7.1
Small Industrial (21)	1.8	1.9	1.9	5.6
Medium Industrial (22)	1.0	1.0	1.1	3.1
Large Industrial (23,25)	2.5	2.6	2.7	7.7
Municipal (24)	0.9	0.9	1.0	2.9
Unmetered (999)	0.03	0.03	0.03	0.09
Total	51.1	53.2	55.9	160.1

Includes EE, DR (E1 costs only), and Enabling Strategies investments

Filed Electronically

Appendix C

Attachment 1: 2023-2025 Alternate Scenario Measure-level
Energy Efficiency Technical Tables

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Appendix D

Evidence of David Hill

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NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF AVOIDED COSTS FOR EFFICIENCYONE'S
2023-2025 DEMAND SIDE MANAGEMENT PLAN APPLICATION

Direct Testimony of
David G. Hill, Ph.D.
ENERGY FUTURES GROUP, INC.

On Behalf of
EFFICIENCYONE

February 11, 2022

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I. Identification and Qualifications

Q: Please state your name and professional affiliation.

A: My name is David G. Hill. I am a Managing Consultant at Energy Futures Group.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of EfficiencyOne. EfficiencyOne has the exclusive right to supply Nova Scotia Power (NS Power) with reasonably available, cost-effective efficiency and conservation activities for a ten-year term. The Efficiency Nova Scotia franchise is a public utility regulated by the Nova Scotia Utility and Review Board, which approves agreements between NS Power and EfficiencyOne on the level of DSM activity.

Q: Please describe the role of your current employer in the energy efficiency industry.

A: Energy Futures Group (EFG) is a clean-energy consulting firm headquartered in Hinesburg, Vermont, with offices in Boston and New York. EFG designs, implements, and evaluates programs and policies to promote investments in efficiency, renewable energy, other distributed resources, and strategic electrification. EFG staff have delivered projects on behalf of energy regulators, government agencies, utilities, and advocacy organizations in 42 states, 8 Canadian provinces, and several countries in Europe.

EFG brings to its work a unique combination of technical, economic, program, and policy expertise. EFG staff have critically reviewed and contributed to hundreds of efficiency and renewable energy programs, playing key roles in developing many that have subsequently won awards for excellence. Recent work involves efficiency program portfolios and policies in fourteen of the fifteen highest-ranking states on the ACEEE State Energy Efficiency Scorecard, as well as in Nova Scotia, New Brunswick, Ontario, Manitoba, and British Columbia. EFG staff have provided expert witness testimony on efficiency programs, integrated resource planning, and related policy issues in regulatory proceedings in twenty states and five Canadian provinces.

1 EFG's recent work includes analysis and strategic planning support for the Connecticut Energy Efficiency
2 Board, the Rhode Island Energy Efficiency and Resource Management Council and the Massachusetts
3 Energy Efficiency Advisory Council and Department of Energy Resources. We have also served as
4 technical consultants for Massachusetts Decarbonization Road Map, and as technical consultants to the
5 Vermont Climate Council supporting the recently adopted Climate Action Plan. Additional work includes
6 assessing the potential for geotargeted use of distributed energy resources – "non-wires alternatives" –
7 to cost-effectively defer capital investment in Transmission and Distribution infrastructure; assessing the
8 potential for and impacts of electrification of space heating, water heating and transportation; assessing
9 the role of financing products in advancing investment in clean energy; and designing and implementing
10 residential retrofit programs in multiple states.

11 **Q: Please professional work experience and education.**

12 A: I joined Energy Futures Group ("EFG") in January of 2020. In the electric sector recent work
13 includes serving as senior advisor for EfficiencyOne with initial scoping and portfolio review for the
14 2023-2025 Demand Side Management (DSM Plan), submitting and defending expert testimony on the
15 characterization and analysis of energy efficiency and demand response in Dominion Energy South
16 Carolina's 2020 Integrated Resource Plan on behalf of the Southern Environmental Law Center and the
17 Coastal Conservation League. In 2019, I presented at a technical workshop on efficiency portfolio
18 diversification and submitted supporting testimony in Nova Scotia on behalf of EfficiencyOne. In 2018, I
19 provided testimony on behalf of the Ecology Action Centre to the Nova Scotia Utility and Review Board
20 regarding NS Power's Advanced Metering Infrastructure project. From 2010 to 2020, I provided ongoing
21 expert review and testimony on EmPOWER Maryland's energy efficiency portfolio on behalf of that
22 state's Office of People's Counsel.

23 My recent and current work also includes several assignments relating to gas infrastructure, pilot
24 programs, and planning. In early 2020, I led an EFG team, and was the lead author for a critical
25 assessment of National Grid's long-term needs assessment of gas supplies and proposed pipeline
26 infrastructure investments for their downstate New York service territories. I was also the lead author
27 for a whitepaper, prepared for Conservation Law Foundation, which assessed critical issues for gas
28 system infrastructure investments in Rhode Island. In 2021, I filed expert witness testimony with the
29 Illinois Commerce Commission on three proposed gas pilot programs in Illinois on behalf of Citizen's

Utility Board, Environmental Defense Fund and the Natural Resources Defense Council. Other recent work related to long term energy planning and the future of gas include serving as a co-leader of the technical consultant team for the Vermont Climate Council as they developed and adopted a Climate Action Plan to meet the requirements of Vermont's Global Warming Solutions Act, and leading a team conducting building sector analyses and integrated scenario planning for the Massachusetts Decarbonization Roadmap.

Prior to joining EFG, I worked for the Vermont Energy Investment Corporation ("VEIC") for 22 years, starting in 1998 as an analyst, subsequently holding several positions over the decades, and serving my last five years as Director of Distributed Resources and Policy Fellow. As the Director of Distributed Resources and a Policy Fellow at VEIC, I was responsible for advancing sustainable energy program design and evaluation. For two decades, I regularly led major consulting assignments at VEIC, being best known for my work in distributed energy resources, particularly solar energy. I provided expert testimony and regulatory support on renewable energy and energy efficiency in six jurisdictions in Canada and the United States. I was regularly engaged as an expert on renewable energy market design and regulatory issues at international, national and regional conferences and workshops. I served on national, state, and local level boards. I also led policy committees and conferences, and comprehensive studies of the economic, technical, and achievable potentials for sustainable energy programming. My work also supported detailed level program budget planning and implementation.

Over the years, I have led or significantly contributed to the design and development of more than six large programs, with annual budgets of \$100+ million, for initiatives in New Jersey, New York, Vermont, Arizona, and Maryland.

I earned my Ph.D. in Energy Management and Policy Planning at the University of Pennsylvania. Further details on my work experience and education are provided in my professional resume, included as DGH-Exhibit 1.

Q: What is your experience in providing testimony?

A: Over my career, I have provided testimony in regulatory hearings on more than two dozen occasions and have participated in scores of technical workshops and working groups on behalf of many

1 clients, including participation in several proceedings in Nova Scotia. Exhibit DGH-1 provides further
2 details on my experience as an expert witness.

3 II. Executive Summary

4 **Q: Please summarize your testimony, and primary findings.**

5 **A:** The purpose of my testimony is to assess the demand side management (DSM) avoided costs
6 Nova Scotia Power (NSP) has provided to EOne based on its 2020 Integrated Resource Plan (IRP) for use
7 in the development of the 2023-2025 DSM Plan. Avoided costs for DSM are used by EOne in its portfolio
8 and program planning and development to represent the “value” for avoided energy and capacity costs
9 and to calculate the cost effectiveness of individual measures, programs, and the full DSM portfolio.

10 Specifically, I discuss and critique NSP’s use of scenario 2.0C as NSP’s basis for the DSM avoided
11 costs. I find three major issues with the use of 2.0C as the basis for the avoided cost calculations for the
12 2023-2025 DSM plan.

- 13 • Scenario 2.0C is based on the retirement of coal plants by 2040. The Environmental Goals and
14 Climate Change Reduction Act (Bill 57)¹ has established 2030 as the phase out date for
15 retirement of coal.
- 16 • Scenario 2.0C is based on a low level of electrification for transportation and buildings. The low
17 case for electrification does not reflect Provincial and Federal requirements and the pace of
18 market and technical change.
- 19 • Scenario 2.0C is also not aligned with the renewable energy standard of 80% by 2030 contained
20 in Bill 57.

21 IRP scenario 3.1C is better aligned with the current landscape on each of these issues, and
22 therefore provides a more accurate and valid basis for the development of DSM avoided costs. I
23 provide a high-level qualitative assessment of the impacts on avoided costs if 3.1C is used as a basis for

¹ [Nova Scotia Legislature - Bill 57 - Environmental Goals and Climate Change Reduction Act - RA \(nslegislature.ca\)](https://www.nslegislature.ca/bills/57)

1 calculating DSM avoided costs in place of 2.0C. For each of the three issues listed the use of 2.0C is
2 “conservative” producing lower avoided costs for DSM than would result from 3.1C.

3 The higher avoided costs for energy and capacity that would result if avoided costs were based
4 on the more appropriate 3.1C scenario, will lead to higher levels of demand side management being cost
5 effective in EOne’s 2023-2025 DSM plan.

6 The use of 2.0C as the basis for DSM avoided costs for the 2023-2025 plan runs counter to NSP’s
7 commitment to an “Evergreen” IRP process. The Deep Decarbonization Study and the IRP recognize the
8 importance of DSM in meeting the Sustainable Development Goals Act targets and in reducing the costs
9 of building and transportation electrification needed to meet these targets. The issues with use of 2.0C
10 for determining avoided costs have become more sharply defined with the passage of Bill 57. However,
11 the trends making a scenario such as 3.1C more applicable have been apparent for some time, and in my
12 opinion, it is a serious oversight that avoided costs based on a scenario more reflective of the current
13 landscape were not calculated and provided to EOne for use in analysis of the 2023-2025 DSM portfolio.

14 Looking forward, I recommend NSP use scenario 3.1C (updated for other factors as appropriate)
15 – as the basis for calculating avoided costs for DSM in the Evergreen IRP process. The new calculations
16 should use a “no new DSM case” as a comparison for determining the value of efficiency in a medium
17 and high electrification futures under the 2030 retirement of all coal plants and an 80% renewable
18 energy standard by 2030. This analysis should also include DSM decrements to load that accurately
19 reflect the base, medium and high levels of DSM savings identified by EOne’s potential study analyses
20 and the 2023-2025 DSM Plan Application.

21 In the meantime, I recommend the NSUARB recognize EOne’s 2023-2025 filing is based on
22 “conservative” estimate of DSM avoided costs as it relies on an outdated 2.0C scenario that does not
23 accurately reflect Nova Scotia’s planning landscape, and qualitatively account for this conservatism in
24 the Board’s review of the 2023-2025 plan application.

25 **III. The Integrated Resource Plan Scenarios**

26 **Q: Please start by describing the IRP Scenario that NSP has used as the basis for DSM avoided**
27 **costs.**

1 **A:** NSP has adopted and maintained the use of scenario 2.0C for determination of avoided DSM
 2 costs. “NSP will calculate Avoided Costs of DSM (capacity and energy) for scenarios 2.0C and 2.1C. 2.0C
 3 will be used as the Reference Plan and 2.1C will be available for additional reference.”² The January
 4 2022 Action Plan Update continues to use 2.0C as the basis for avoided costs for DSM.³

5 **Q:** What are the key elements of Scenario 2.0C and 2.1C?

6 **A:** Key elements of scenario 2.0C are a low level of future electrification, the retirement of coal
 7 plants by 2040, regional integration of the electric system and greenhouse gas emissions being on a net-
 8 zero by 2050 trajectory. Scenario 2.1C has the same key elements as 2.0C with the addition of a
 9 medium level of electrification for building and transportation. Figure 8 from the November 2020 IRP⁴
 10 summarizes the historic and future generation mix for the two scenarios.

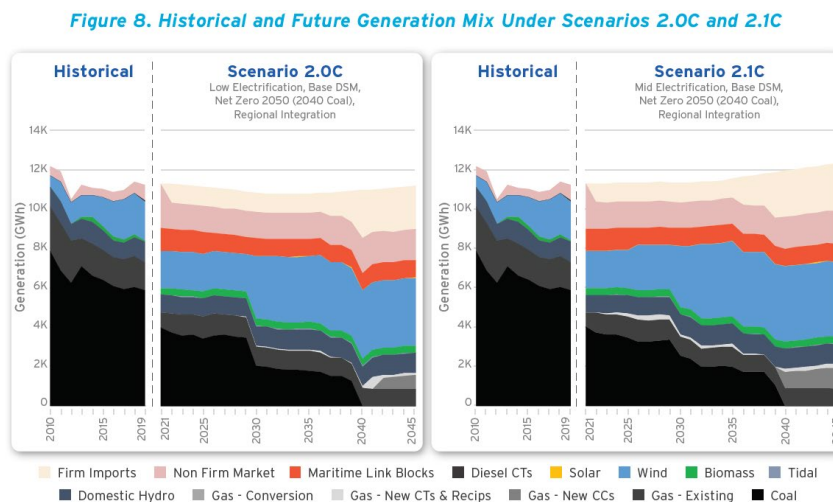


Figure DGH-1 Generation Mix for Scenarios Used to Calculate DSM Avoided Costs

13 **Q:** Has legislation been passed in Nova Scotia that would be at odds with the key elements of
 14 **Scenarios 2.0C and 2.1C?**

² *Powering a Green Nova Scotia, Together: 2020 Integrated Resource Plan*, Nova Scotia Power, November 27, 2020. Page 27.

³ Nova Scotia Power, IRP Action Plan Update, January, 2022. Slide 75.

⁴ NSP 2020 IRP, page 20.

1 **A:** Yes. Bill No. 57, the Environmental Goals and Climate Change Reduction Act, passed by the 1st
 2 Session of the 64th General Assembly in November of 2021 includes two key provisions making scenarios
 3 2.0C and 2.1C planning assumptions obsolete. Specifically, Section 7 (l) to have 80% of electricity in the
 4 Province supplied by renewable energy by 2030; and (m) to phase out coal-fired electricity generation in
 5 the Province by the year 2030.⁵

6 **Q:** Is there a Scenario developed in NSP's 2020 IRP that more accurately reflects the milestones
 7 in Bill 57?

8 **A:** Yes. Scenario 3.1C is a better choice for at least three major reasons. First, it is based on the
 9 retirement of coal by 2030 as required by Bill 57. Scenario 3.1C also has higher levels of renewable
 10 electricity generation by 2030 and is therefore more aligned with the 80% renewable electricity
 11 generation requirement of Bill 57. Finally, scenario 3.1C also includes a mid-level of electrification,
 12 which is consistent with current market conditions and levels of electrification required to meet net zero
 13 greenhouse gas emission reduction targets. Table DGH-1 provides a qualitative comparison of scenario
 14 3.1C with 2.0C and 2.1C providing backing for my assertion that Scenario 3.1C more accurately reflects
 15 Nova Scotia's policy and planning environment, and that 2.0C is outdated as the basis for DSM avoided
 16 cost calculations.

17 **Table DGH-1: Comparison of IRP Scenarios and Alignment with Current Planning and Policy**
 18 **Environment**

Scenario	Plan Element		
	Coal Retirement Date	Renewable* by 2030	Level of Electrification
2.0C – Base DSM	2040	72%	Low
2.0C – Mid DSM	2040	72%	Low
2.1C – Base DSM	2040	68%	Mid
2.1C – Mid DSM	2040	74%	Mid
3.1C – Base DSM	2030	92%	Mid

19 **Assuming Renewable for all Maritime link, Non -Firm Imports and Firm Imports based on 2030 values*
 20 *from Appendix F of the 2020 NSP IRP.*

21 In Table DGH-1 I have used red to indicate areas where plan elements are clearly out of date and
 22 do not reflect the Bill 57 and the current planning environment. Yellow indicates caution, as NSP's

⁵ [Nova Scotia Legislature - Bill 57 - Environmental Goals and Climate Change Reduction Act - RA \(nslegislature.ca\)](https://www.nslegislature.ca/bills/57)

1 January 2022 IRP Update indicates that high electrification is likely the best set of scenario planning
2 assumptions for electrification.

3 **Q: Does NSP recognize that the differences in these plan elements between the scenarios as**
4 **having material impact on results?**

5 **A:** Yes. In the IRP's Section 1.8 Overview of Key Findings NSP indicates:

- 6 • *"When coal retirements are required by 2030 in combination with accelerated GHG reduction*
7 *targets, the replacement firm capacity and energy resource requirements create higher costs*
8 *leading up to that year as generating resources are replaced. This contributes to a higher net*
9 *present value (NPV) over the entire IRP planning horizon."*⁶

10 In Section 6.4 on Resource Plan Costs, the IRP states:

- 11 • *"The comparison in this figure also shows that meeting a 2030 coal retirement date is more*
12 *expensive, on an NPV basis, than a comparable scenario with a 2040 coal retirement date."*⁷

13 **Q: Does NSP discuss the types of changes in the planning environment that lead to IRP updates?**

14 **A:** Yes. NSP recognizes that changes in key external influences on the long-term planning
15 environment can trigger the need to update or conduct new IRP analyses. Quoting several passages
16 from the November, 2020 IRP:

- 17 • *"IRPs are carried out when material changes in the key external influences underlying Nova*
18 *Scotia Power's long-term planning environment, such as environmental policy or market*
19 *landscape, trigger a need to revisit the long-term planning strategy"*⁸
20 • *"One of the objectives of Nova Scotia Power's IRP is to produce a robust long-term electricity*
21 *strategy that can withstand realistic potential changes to key assumptions."*⁹ and
22 • *"Nova Scotia Power should continue to monitor for external factors that could influence coal*
23 *retirement dates or provide opportunities to reduce the cost and relative rate gap between 2040*
24 *and 2030 coal retirement scenarios."*¹⁰

⁶ NSP 2020 IRP, page 24.

⁷ NSP 2020 IRP, page 94.

⁸ NSP 2020 IRP, Section 2 Objectives of the IRP page 30.

⁹ NSP 2020 IRP, Section 7 Key Findings, page 111.

¹⁰ NSP 2020 IRP, Section 7 Key Findings, page 111.

1 **Q: Have the NSUARB, and stakeholders, considered the impact of using scenario 2.0C as the**
2 **basis for determination of avoided costs given the passage of Bill 57?**

3 **A: Yes. In Matter 10176, regarding approval of a Solar Garden Pilot Rider advocates identified**
4 **scenario 3.1C as a better reflection of Bill 57 requirements. In its decision the NSUARB stated:**

- 5 • *“Taking into account all of the above, the Board accepts the evidence of Synapse and Resource*
6 *Insight that the SG Rider credit may understate the net value of solar energy from the solar*
7 *garden to the grid.”¹¹*

8 Similar reasoning is applicable here, making it likely the value of energy efficiency based on avoided
9 costs determined based on Scenario 2.0C is understated.

10 **IV. Impact on Avoided Costs of Shifting to Scenario 3.1C**

11 **Q: Have you conducted an analysis of the direction and magnitude of impacts if Scenario 3.1C is**
12 **used as the basis for determining avoided costs for DSM energy and capacity?**

13 **A: Yes, at a high-level. While fully recalculating avoided costs for DSM based on an alternative**
14 **scenario is appropriately considered the responsibility of NSP as part of an Evergreen IRP process, I have**
15 **conducted a high-level comparison of the net present value of revenue requirements (NPVRR) for the**
16 **various scenarios and DSM sensitivities as presented in the IRP. As a first step I compare the NPVRR**
17 **when shifting from scenario 2.0C to scenario 2.1C (representing moving from low to medium levels of**
18 **electrification), followed by the comparison of the increase in NPVRR when shifting from 2.0C to 3.1C**
19 **(which represents the 2030 coal retirement and the medium level of electrification). These comparisons**
20 **for both the base and medium levels of DSM, are presented in Table DGH-2.**

21

¹¹ Nova Scotia Utility and Review Board, Decision 2021 NSUARB 139 M10176, November 10, 2021, Finding 28, Page 10.

1

Table DGH-2: NPVRR Scenario Comparisons¹²

<u>Base DSM</u>	<u>2.0C (ref)</u>	<u>2.1C</u>	<u>3.1C</u>
Increase from low to mid electrification		7.51%	
Increase from low to mid Electrification and 2030 coal retirement			12.42%
<u>Mid DSM</u>	<u>2.0C (ref)</u>	<u>2.1C</u>	<u>3.1C</u>
Increase from low to mid electrification		7.37%	
Increase from low to mid Electrification and 2030 coal retirement			11.64%

2

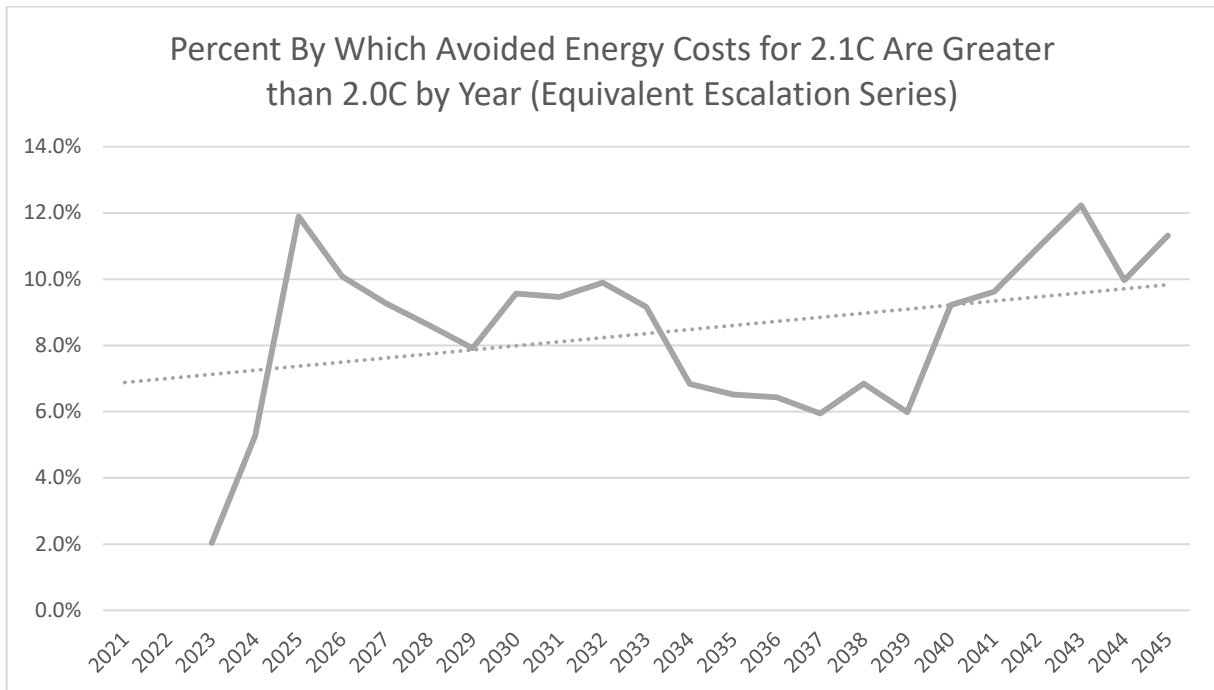
3 As illustrated in Table DGH-2 shifting to the scenarios that include medium levels of
 4 electrification and the retirement of coal plants by 2030 increases the present value of revenue
 5 requirements by more than 7% for 2.1C, to more than 11% with a shift from 2.0C to 3.1C. These
 6 comparisons are directional, and do not replace the need for re-calculation of the avoided costs using
 7 scenario 3.1C as the resource plan that more accurately reflects the current planning environment.

8 The observed increase in NPVRR does not mean that avoided costs would directly increase by
 9 the same amounts, they could be more or less than the increase in NPVRR. Full recalculation of the
 10 avoided costs for DSM with scenario 3.1C requires a comparison of the costs for the selected scenario
 11 with and without DSM, and this is beyond the scope of my testimony. Directionally, however we can
 12 see that both electrification and the retirement of coal plants by 2030 lead to higher system revenue
 13 requirements. As a resource DSM can be expected to avoid and or reduce the need for some of the
 14 additional resources driving the higher revenue requirements.

15 **Q: Have you conducted any further comparison that can further understanding of the potential**
 16 **magnitude of differences in avoided costs if 2.0C is not the basis for comparison?**

¹² Based on 25-year NPVRR without end-effects from Appendix E, NSP 2020 IRP.

1 A: Yes. I also compared the difference in the avoided energy costs for 2023 to 2045 calculated by
 2 NSP between scenarios 2.0C and 2.1C, as presented in the January 2020 IRP Update¹³, and NSP's AVC of
 3 DSM calculations workbook.¹⁴ Scenarios 2.0C and 2.1C both still have a 2040 coal retirement date, and
 4 therefore they only partially reflect the changes that would be associated with using 3.1C with 2030 coal
 5 retirement and mid-levels of electrification for avoided cost calculations, and 3.1C is the most
 6 appropriate for use with EOnes 2023-2025 DSM plan. Figure DGH-2 illustrates the percent by which the
 7 annual avoided energy costs for 2.1C are greater than those for 2.0C.



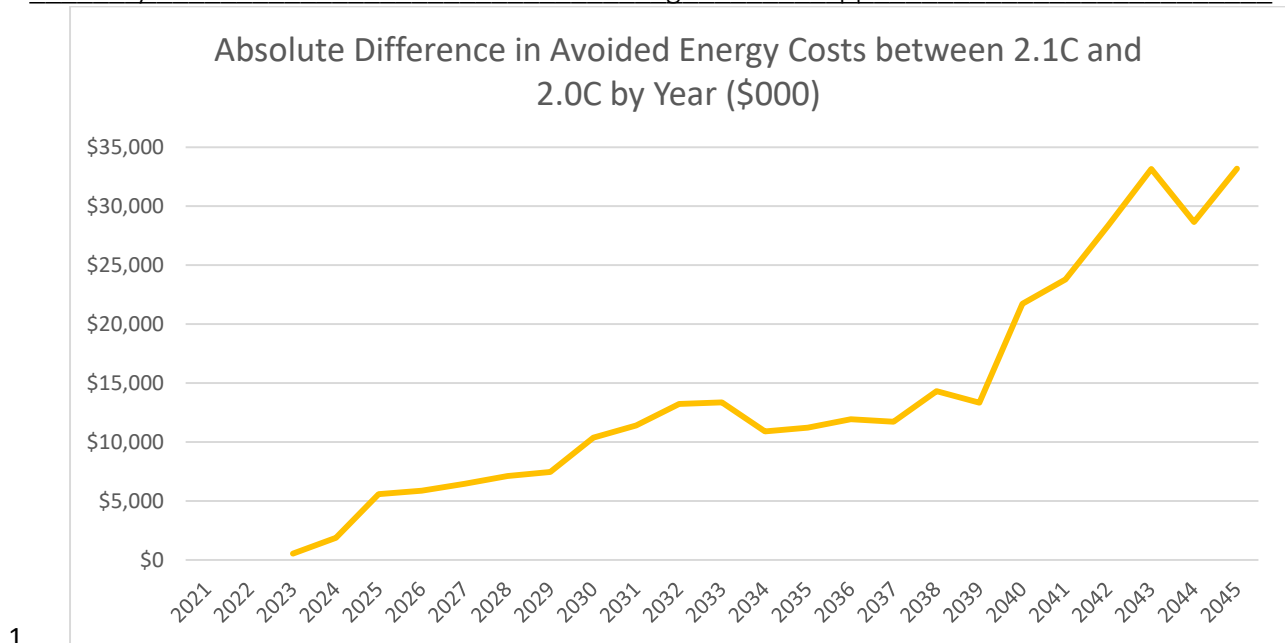
8
 9 **Figure DGH-2: Comparison of NSP Calculated Avoided Costs for Scenario 2.0C and 2.1C¹⁵**

10 A simple linear fitted line (dotted line) in Figure DGH-2 illustrates the avoided energy costs for
 11 scenario 2.1C exceed those for 2.0C by more than 6% to almost 10%, with the highest annual difference
 12 exceeding 12%. Figure DGH-3 illustrates the absolute difference in dollars for avoided energy costs
 13 between the same two scenarios.

¹³ NSP January 2020 IRP Update, Slide 80.

¹⁴ 2021-08-20 Attachment2 – AVC of DSM Calculations.

¹⁵ Calculated as (AVC 2.1C NPV 2023 (Col. L) divided by AVC 2.0C NPV 2023 (Col. K))-1.



1

2 **Figure DGH-3: Absolute Difference in Annual Avoided Energy Costs between Scenario 2.0 C and 2.1C¹⁶**

3 Here we see annual differences that start at more than \$500,000 in 2023, with substantial increases
 4 to more than \$5 million each year after 2025 reaching a high of more than \$33 million in 2043. The
 5 cumulative value of the difference in avoided costs over a twelve-year period from 2023 to 2035, which
 6 is a simple proxy for the average measure life of DSM measures, is \$105 million. These results are
 7 logical, with a relatively straightforward narrative explanation – as electrification increases and load
 8 grows it makes sense to expect higher values for avoiding new energy and capacity resources.

9 **Q: Have you conducted a similar comparison of the difference in avoided capacity costs**
 10 **between Scenarios 2.0C and 2.1C?**

11 **A:** Yes, a relative comparison of the avoided capacity costs between Scenarios 2.0C and 2.1C is
 12 presented in Figure DGH-4. Here, we see capacity costs for the mid electrification scenario (2.1C) are
 13 higher than for the low electrification scenario (2.0C) through 2037. Once again, this makes intuitive
 14 sense as higher levels of electrification can be expected to result in a greater need for new capacity
 15 resources and therefore higher avoided capacity costs. Looking at a twelve-year measure life for DSM

¹⁶ Calculated as AVC 2.1C NPV 2023 (Col. L) minus AVC 2.0C NPV 2023 (Col. K).

savings, over the period of 2023-2035, the capacity values for 2.1C are on average 21.48% higher than for scenario 2.0C. The capacity results are directionally the same as for the energy avoided costs and further highlights that use of 2.0C as the basis for the DSM avoided cost determination undervalues both energy and capacity savings.

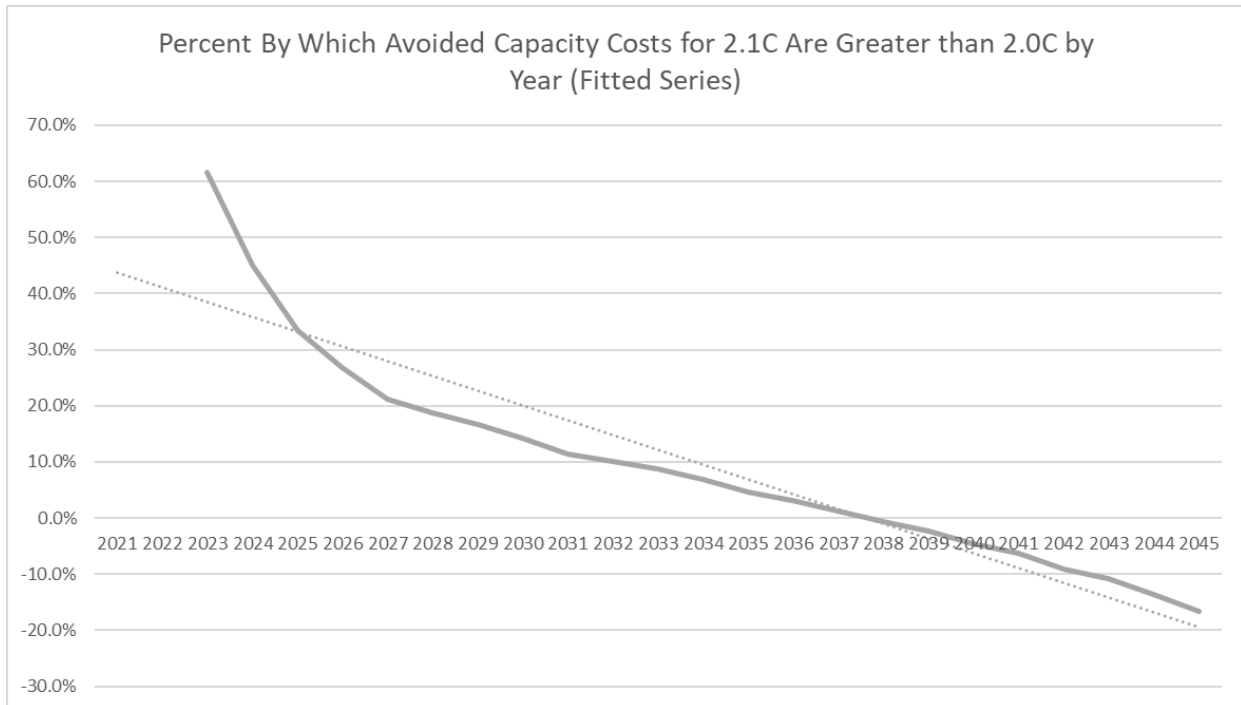


Figure DGH-4: Percent Difference in Annual Avoided Capacity Costs between Scenario 2.0 C and 2.1C¹⁷

V. Efficiency and Electrification as Critical Strategic Resources to Meet SDGA Targets

Q: Is it reasonable to anticipate levels of electrification higher than those represented in scenario 2.0C?

¹⁷ Avoided Capacity Costs \$/kw-yr. (Fitted Series) from January 2022 IRP Action Plan Update Slide 81.

- 1 **A:** Definitely. Figure DGH-4 shows the electrification scenario details from the NSP November 2020
 2 IRP.¹⁸

		Low Electrification	Mid Electrification	High Electrification
Sales of electric heat pumps and water heaters		25% sales of air source heat pumps for space heating by 2050	50% sales of heat pump space heaters and water heaters by 2040 in the residential and commercial sectors	100% sales of heat pump space heaters and water heaters by 2030 in the residential sector 98% sales of heat pump space heaters and 93% sales of heat pump water heaters by 2040 in the commercial sector
Electric vehicle penetration	LDVs	2% Zero Emission Vehicles (ZEV*) sales by 2050	50% EV sales by 2040	100% EV sales by 2040
	MDVs	2% EV sales by 2050	90% diesel electric hybrid sales by 2050	80% EV sales by 2040 and 9% diesel electric hybrid sales by 2050
	HDVs	0.5% EV sales by 2050	100% diesel electric hybrid sales by 2050	20% EV sales by 2030 and 60% EV sales by 2050
	Buses	5% EV sales by 2030	5% EV sales by 2030	60% EV sales by 2040

Figure DGH-4: Electrification Scenario Details from NSP November 2020 IRP

The low electrification scenario which is embedded in scenario 2.0C has been, and continues to be, used by NSP as the primary basis for calculating DSM avoided costs, has only a **2% adoption of EVs as portion of new sales by 2050**. Figure DGH-5 provides a comparative slide from the January 2022 IRP Update¹⁹ from NSP illustrates how the low electrification scenario assumptions are seriously out of synch with the current policy and planning. Figure DGH-5 indicates EV sales are expected to reach 100% market share by 2035, earlier than anticipated even the high electrification scenario above. The January 2022 IRP update contains similar estimates for residential and commercial heat pumps that indicate even the mid electrification scenario assumptions are likely conservative.

¹⁸ NSP 2020 IRP, Figure 22, page 57.

¹⁹ NSP January 2022 IRP Action Plan Update, Slide 33.

Modeled Light-Duty EV Adoption

Light duty EV adoption/stock estimate was developed in E3's PATHWAYS stock rollover model.

- Base case forecasts that follow currently rely on a “slow sales ramp” scenario, which assumes 30% electric LDV sales reached by 2030 (provincial target) and 100% by 2035 (federal announced target).

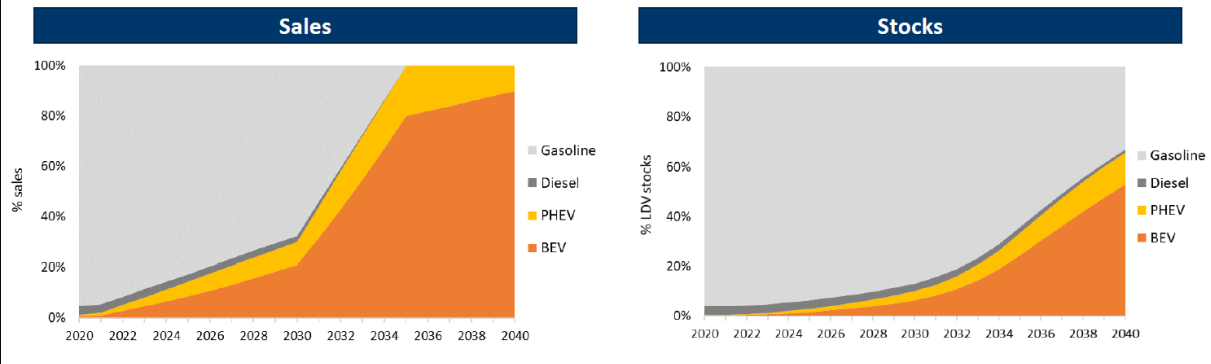


Figure DGH-5: January 2020 IRP Action Plan Update Illustrates EV Assumptions Aligned with High Electrification Assumptions

In earlier comments, EOne has noted that higher levels of electrification are likely to render DSM resources more competitive.²⁰ The importance of DSM as a resource, the need for early action, and the need to apply strategies beyond a decarbonized grid to meet targets and reduce system costs in a deep decarbonization world have also been stressed by E3 Economics in studies conducted for NSP.²¹

VI. Conclusions and Recommendations

Q: Please summarize your conclusions based on your review and analysis.

A: In summary, my conclusions are as follows:

- The use of 2.0C as a basis for determination of DSM avoided costs is outdated, and flawed in three fundamental areas:
 - Coal retirement dates
 - Renewable energy standard, and
 - Levels of electrification

²⁰ EOne Memo September 18, 2020 page 5 of 10, included in NSP 2020 IRP Appendix K, page 194.

²¹ Deep Decarbonization in Nova Scotia: Phase I Report, E3 Economics, NSP 2020 IRP, Appendix A. see pages 40 related to final energy demand, pages 50-51 related to early action and need for more than decarbonized grid.

- 1 • Scenario 3.1 C is a better based for determination of avoided costs in relation to each of these
2 issues.
- 3 • Scenario 3.1C has higher NPVRR in comparison to 2.0C and can be expected to result in higher
4 DSM avoided costs.
- 5 • My comparative analysis of NSP's avoided costs using 2.1C as opposed to 2.0C as the reference
6 scenario illustrates how increasing electrification has a significant impact on avoided costs. The
7 levels of electrification represented by 2.0C are unreasonably low and completely out of date.
8 Even the mid-level of electrification represented in scenarios 2.1C and 3.1C are likely
9 conservative based on information presented in the January 2022 IRP Action Plan Update.
- 10 • Advocates and the UARB's Solar Garden decision recognize the issues with using 2.0C as basis
11 for determining the value solar generation to the grid. The same logic applies to use for avoided
12 DSM costs.

13 **Q: Please review the recommendations you have for the Board.**

14 **A:** I recommend the NSUARB Board should direct NSP to calculate new DSM avoided energy and
15 capacity costs as part of the Evergreen IRP process, using scenario 3.1C (updated for other factors as
16 appropriate) – as the reference in place of scenario 2.0C. The new analysis should use a “no new DSM
17 case” as a comparison for determining the value of efficiency in high and medium electrification futures
18 under the 2030 retirement of all coal plants with an 80% renewable energy standard by 2030. This
19 analysis should include DSM decrements to load that accurately reflect the base, medium and high
20 levels of DSM savings identified by EOne's potential study analyses, and the levels of DSM savings
21 presented in the 2023-2025 Plan Application.

22 In the meantime, I recommend the NSUARB recognize EOnes 2023-2025 filing is based on
23 “conservative” estimates of DSM avoided costs as it relies on an outdated 2.0C scenario that does not
24 accurately reflect Nova Scotia's planning landscape, and qualitatively account for this conservatism in
25 the Board's review of the 2023-2025 plan.

26 **Q: Does this conclude your testimony?**

27 **A:** Yes, it does.

Appendix E

Evidence of Scott Robinson

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DIRECT TESTIMONY OF
SCOTT ROBINSON
ON BEHALF OF
EFFICIENCYONE

**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND
OCCUPATION.**

A. My name is Scott Robinson. I am a Director in the Advanced Solutions group at Guidehouse Inc., formerly Navigant Consulting, Inc. My business address is 1375 Walnut Street, Boulder, CO. Today, I will be filing testimony on behalf of EfficiencyOne.

**Q. BRIEFLY STATE YOUR EDUCATION, BACKGROUND, AND
EXPERIENCE.**

A. I have master's degrees from the University of Texas (USA) at Austin's Jackson School of Geoscience in the Energy and Earth Resources program, and the University of Texas (USA) at Austin's Lyndon B. Johnson School of Public Affairs. I have published multiple peer-reviewed journal articles on modeling technology economics and diffusion.^{1,2,3} For the last eight years, I have worked in

¹ Robinson, S. A., & Rai, V. (2015). Determinants of spatio-temporal patterns of energy technology adoption: An agent-based modeling approach. *Applied Energy*, 151, 273-284; Rai, V., & Robinson, S. A. (2013). Effective information channels for reducing costs of environmentally-friendly technologies: evidence from residential PV markets. *Environmental Research Letters*, 8(1), 014044

² Rai, V., & Robinson, S. A. (2015). Agent-based modeling of energy technology adoption: Empirical integration of social, behavioral, economic, and environmental factors. *Environmental Modelling & Software*, 70, 163-177.

1 distributed energy resources, transportation electrification, and energy efficiency
2 at Guidehouse (formerly Navigant). My clients include state and local
3 governments, utilities, and utility regulatory agencies on topics related to the
4 modeling and impact of energy efficiency, demand response, electric vehicles, and
5 distributed energy resources.

6 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NOVA SCOTIA**
7 **UTILITY AND REVIEW BOARD (UARB)?**

8 A. No, I have never testified before the UARB. However, I have testified
9 multiple times in other regulatory jurisdictions, and authored multiple articles and
10 reports on technology economics, modeling, forecasting, and cost effectiveness,
11 including in Nova Scotia.

12
13 **Q. WHAT ARE YOUR RESPONSIBILITIES AT GUIDEHOUSE?**

14 A. I focus on quantitative forecasting, economic analysis, and simulation of
15 distributed energy, alternative fuel vehicle, and energy efficiency technologies. I
16 lead teams of modelers and am responsible for several of our flagship distributed
17 energy resource simulation models, including DSMSim™, DERSim™, VAST™,
18 GRIP™, as well as ProCESS™. which Guidehouse used to develop the cost-
19 effectiveness testing results for EfficiencyOne. My responsibilities include
20 managing model feature integration, oversight, quality and version control, and

³ Robinson, S. A., et al. (2020). Machine-Assisted Energy Efficiency Portfolio Design in Nova Scotia. Proceedings of the American Council for an Energy-Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings.

1 model enhancement planning. I frequently fill the role of senior modeler, technical
2 quality manager, subject matter expert, lead modeler, or quality control lead on
3 projects. For example, I have led the modeling for more than a dozen demand-side
4 management potential studies, including the 2019 study for EfficiencyOne in
5 Nova Scotia.

6
7 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

8 A. The purpose of this testimony is to discuss standard practices in demand-
9 side-management (DSM) cost-effectiveness testing in relation to EfficiencyOne's
10 2023-2025 Demand Side Management Resource Plan. I provide an overview of
11 cost-effectiveness testing in the context of demand-side management, including
12 standard benefit and cost streams, discount rate usage, common non-energy
13 benefit practices, and appropriate screening granularity. I finish with a summary
14 explaining why EfficiencyOne's cost-effectiveness testing framework is in
15 alignment with industry leading standard practice.

16
17 **Q. WHAT IS THE PURPOSE OF COST-EFFECTIVENESS SCREENING**
18 **FOR DEMAND-SIDE MANAGEMENT PROGRAMS?**

19 A. Cost-effectiveness testing typically is conducted to compare the lifetime
20 benefits to the lifetime costs of a measure, program, or portfolio. A demand-side
21 management (DSM) investment is considered cost-effective if the present value
22 lifetime benefits meet or exceed the present value lifetime costs for a specified

1 discount rate. DSM cost-effectiveness screening has multiple uses throughout
2 DSM plan development and implementation. It is common to screen efficiency
3 measures for cost-effectiveness within demand-side management potential studies.
4 For program design and performance assessment, however, it is more common to
5 aggregate to the program and portfolio level to determine if an investment should
6 be considered or is implemented successfully. There are five standard cost tests
7 that analyze an investment from different stakeholder perspectives. However,
8 jurisdictions usually focus on one primary test to inform the design and
9 implementation of DSM portfolios. The benefits and costs considered vary based
10 on the perspective taken by the cost-effectiveness test. For example, the total
11 resource cost (TRC) test takes the perspective of the utility and program
12 participants, while the program administrator cost (PAC) test takes the perspective
13 of the program administrator alone.

14
15 **Q. WHICH COST-EFFECTIVENESS TESTS ARE MOST COMMONLY**
16 **USED TO ASSESS COST-EFFECTIVENESS OF DEMAND-SIDE**
17 **MANAGEMENT PROGRAMS?**

18 A. The TRC test is the most used primary screening test in North America.
19 Twenty-eight US states use the TRC either alone or in combination with other
20 tests. Four US states use the Societal Cost Test (SCT), and eleven US states use
21 the PAC. Additionally, several northeast US states have begun to adopt state-
22 specific tests in accordance with the National Standard Practice Manual Resource

1 Value Test (RVT) to customize cost testing to specific policy goals.⁴ In Canada,
2 Ontario uses a modified TRC test with a 15% adder for non-energy benefits, and
3 exceptions for low income. British Colombia uses a modified TRC test that
4 includes non-energy benefits and low-income adders (40%). Manitoba uses the
5 PAC test, screening at the portfolio level and allowing non-cost-effective
6 individual programs and program bundles. New Brunswick uses the PAC test
7 supplemented by the Participant Cost Test (PCT).

8
9 **Q. WHAT IS THE PURPOSE OF THE TOTAL RESOURCE COST TEST?**

10 A. The Total Resource Cost (TRC) test measures the net present value benefits
11 and costs of a demand-side management (DSM) measure, program, sector or
12 portfolio from the perspective of both the program administrator and participants.
13 By combining the two viewpoints, the TRC test attempts to balance the cash flows
14 between these two parties. The TRC compares the avoided energy and demand
15 costs for primary and secondary fuel sources with the full cost of efficiency
16 measures and non-incentive administration costs. As a result, this test represents
17 the cost-effectiveness of a demand-side resource to the broader population of
18 participants and non-participants, and is used to compare investments to supply-
19 side alternatives. A TRC result greater than 1.0 indicates that the present values
20 lifetime benefits outweigh the present value lifetime costs.

⁴ Database of State Efficiency Screening Practices. <https://www.nationalenergyscreeningproject.org/state-database-dsp/database-of-state-efficiency-screening-practices/>

1 **Q. WHAT ARE THE COMMON BENEFITS AND COSTS INCLUDED IN**
2 **THE TRC TEST?**

3 A. Common benefits calculated for the TRC test include avoided transmission
4 and distribution costs, avoided generation costs, avoided energy costs, avoided
5 environmental compliance costs associated with generation, avoided equipment
6 operation and maintenance, and other resource benefits, such as avoided water,
7 and secondary fuel usage. Because the TRC test is attempting to capture the
8 perspective of non-participants as well as participants, most jurisdictions include
9 certain quantifiable Non-Energy Benefits (NEBs), such as increased comfort and
10 health. Resource avoided costs usually deliver the majority of benefits. TRC test
11 costs include the incremental technology cost to participants from adopting an
12 efficient alternative, as well as program administrative spending. Typically,
13 incentives are treated as a transfer payment in the TRC test and are therefore not
14 considered a benefit or cost, since the incentives accrue as a credit (cost) to
15 administrators, and a debit (benefit) to customers. One exception to this is in the
16 case of low-income programs, where incentives may be treated like an
17 administrative cost in the TRC test.

18
19 **Q. WHAT WERE THE COST-EFFECTIVENESS TESTING RESULTS FOR**
20 **EFFICIENCYONE'S 2023-2025 DSM SETTLEMENT PLAN?**

21 A. Each program in EfficiencyOne's Settlement Plan achieved a TRC test ratio
22 greater than 1.0 in each of the three years, 2023 to 2025, with the inclusion of the

environmental compliance cost of carbon. The results without the compliance cost of carbon are shown below for illustration purposes only. One program, Residential Efficient Products, does not meet the TRC test 1.0 cost-effectiveness threshold when the compliance benefit stream is excluded. The New Home Construction component within the New Home Residential program is discontinued after 2023 program year implementation.

Table 1. EfficiencyOne Program Benefit Cost Test Results

Avoided Cost Treatment	Program	Total Resource Cost Test Benefit-Cost Ratio		
		2023	2024	2025
No Carbon	Custom Incentives	1.69	1.71	1.72
	Direct Installation	1.48	1.53	1.57
	Efficient Product Rebates	2.50	2.54	2.59
	New Residential	2.38	N/A	N/A
	Existing Residential	1.08	1.12	1.15
	Residential Efficient Products	0.71	0.69	0.70
With Carbon	Custom Incentives	2.52	2.53	2.49
	Direct Installation	2.19	2.23	2.24
	Efficient Product Rebates	3.74	3.75	3.74
	New Residential	2.58	N/A	N/A
	Existing Residential	1.48	1.55	1.57
	Residential Efficient Products	1.14	1.08	1.07

Q. IS THE VIEW INCLUDING THE COST OF CARBON (“WITH CARBON”) THE MOST APPROPRIATE?

A. EfficiencyOne calculated the TRC test using avoided costs with and without the avoided environmental compliance cost of carbon. In Matter M08604 approving the 2019 DSM Resource Plan, EfficiencyOne was directed by the UARB to incorporate the value of avoiding CO₂e emissions in its DSM cost effectiveness analysis. Accordingly, the without-carbon results should be used for

1 informational purposes only. Amendments to the Environment Act of 2017⁵
2 allowed the development of Cap-and-Trade Program Regulations⁶ to be developed
3 in Nova Scotia, and made Nova Scotia Power a mandatory participant in the
4 program and associated auctions setting the effective carbon price. In 2022 the
5 floor price is set at \$22.92.⁷

6
7 **Q. IS EFFICIENCYONE'S TRC TEST FORMULATION CONSISTENT**
8 **WITH STANDARD PRACTICES?**

9 A. Yes. EfficiencyOne's TRC test includes all appropriate benefits and costs.
10 EfficiencyOne's avoided cost benefit categories include electric energy, electric
11 coincident peak demand, natural gas, wood biomass, and water. For measures
12 where consumption is increased for a specific fuel type, the increase in costs is
13 considered a negative benefit in the TRC test. For instances where the avoided
14 costs summed over all types are negative, EfficiencyOne has calculated a TRC test
15 result of 0.0. Incremental measure costs and variable and fixed administrative
16 spending are applied as costs in the TRC test. Additionally, EfficiencyOne's TRC
17 test formulation is consistent with National Standard Practice Manual (NSPM)
18 guidelines in that it endeavors to calculate reasonably quantifiable impacts, is
19 symmetrical in that it considers all benefits and costs associated with a relevant

⁵ Bill C-28, *online*: <https://parl.ca/DocumentViewer/en/43-2/bill/C-28/first-reading>

⁶ <https://www.novascotia.ca/just/regulations/regs/envcapandtrade.htm>

⁷ The reserve price was set to \$20 in 2020 and increases by 5% per year plus inflation.

https://climatechange.novascotia.ca/sites/default/files/Detailed_Auction_Requirements_and_Instructions.pdf

1 type of impact, is forward looking for the duration of the incentivized measure's
2 useful lifetimes, and screens at the program level.

3
4 **Q. HOW DID EFFICIENCYONE INCORPORATE THE COST OF CARBON**
5 **IN ITS AVOIDED COST ESTIMATES?**

6 A. As directed by the UARB, EfficiencyOne has included Nova Scotia
7 Power's (NSP) avoided cost of carbon compliance costs into the TRC test
8 calculation. To calculate this additional benefit in the TRC test, EfficiencyOne
9 uses the formula:

$$10 \quad AC_{carbon} (\$) = Savings \left(\frac{kWh}{unit} \right) * Intensity \left(\frac{tonnes}{kWh} \right) * Price \left(\frac{\$}{tonne} \right).$$

11 To develop a \$/kWh carbon benefit, EfficiencyOne used the Federal trajectory of
12 the cost of carbon⁸ and carbon intensity from the Nova Scotia Power (NSP)
13 Integrated Resource Plan (IRP) Avoided Costs of Energy and Capacity analysis.
14 This benefit is scaled based on EfficiencyOne's plan savings to yield total carbon
15 benefits. The resulting value of avoided carbon compliance costs increases the
16 avoided cost of energy savings by 80%. As is consistent with NSPM guidelines,
17 this benefits stream is reasonably quantifiable and symmetrical in its application.

18
19 **Q. HOW DO DISCOUNT RATES IMPACT THE TOTAL RESOURCE COST**
20 **TEST?**

⁸ Environment and Climate Change Canada. 2020. A Healthy Environment and a Healthy Economy: Canada's Strengthened Climate Plan to Create Jobs and Support People, Communities and the Planet.

1 A. In all financial modelling, discount rates represent a perspective about the
2 future. For example, a high discount rate may be used to indicate uncertainty about
3 the future, or to indicate a belief that the future will be much more prosperous due
4 to growth. In effect, we often use discount rates to determine tradeoffs between
5 present costs and future benefits. Discount rates are used in the TRC test to
6 discount future benefit and cost cash flows to present value dollars. The discount
7 rate implies that there is greater value in dollars today than in the future and sets
8 an investment hurdle rate. Often, the utility Weighted Average Cost of Capital
9 (WACC) is used in the TRC test to compare demand-side investments to other
10 financial opportunities within a utility's capital structure. Higher discount rates
11 result in lower present value benefits and costs. Benefits in the TRC test are more
12 heavily impacted by discount rates because the benefit of DSM programs
13 commonly last 10 to 20 years into the future—based on the efficiency measures'
14 lifetimes—while costs are generally incurred in the year of program
15 implementation.

16
17 **Q. IS EFFICIENCYONE'S USE OF DISCOUNT RATES CONSISTENT WITH**
18 **CURRENT INDUSTRY PRACTICE?**

19 A. Yes. EfficiencyOne applied Nova Scotia Power's Weighted Cost of Capital
20 (WACC) of 6.33% in its TRC test calculations. Using WACC as the discount rate
21 in the TRC test is typical. However, because the TRC test represents multiple
22 actors, a more accurate approach would be to use discount rates that reflect the

1 perspective of each actor in the transaction (or at least a weighted average discount
2 rate). In the US, there are several TRC screening states (Delaware, Illinois,
3 Massachusetts, and Wisconsin)⁹ that use lower societal discount rates between
4 0.3% and 4%.¹⁰
5

6 **Q. IS EFFICIENCYONE’S TRC TEST CONSERVATIVE?**

7 A. Yes, there are several areas that make EfficiencyOne’s TRC test results
8 conservative relative to practices in other states or provinces. First, fixed and
9 variable administrative costs are allocated at the program component, program,
10 and portfolio level. Second, EfficiencyOne does not carve low-income out of the
11 benefit cost testing as an exemption, as many other states do.¹¹ Third,
12 EfficiencyOne uses the WACC as the discount rate. This increases the
13 conservatism of the testing by more heavily discounting future cashflows to
14 participants. The use of the WACC is in accordance with standard practice when
15 evaluating programs using the TRC test. Fourth, EfficiencyOne uses only the
16 minimum clearing floor cost of carbon emissions compliance to represent the cost
17 of carbon emissions. The minimum clearing price is the most conservative
18 compliance cost appropriate to use in Nova Scotia. Fifth, EfficiencyOne includes

⁹ National Energy Screening Project. <https://www.nationalenergyscreeningproject.org/state-database-dsp/database-of-state-efficiency-screening-practices/>

¹⁰ The Database of State Efficiency Screening Practices (DSESP). <https://www.aceee.org/topic-brief/dsesp>

¹¹ National Energy Screening Project. <https://www.nationalenergyscreeningproject.org/state-database-dsp/database-of-state-efficiency-screening-practices/>

1 the screening results without the compliance cost of carbon emissions for
2 illustration purposes.

3
4 **Q. HOW IS TRC SCREENING COMMONLY USED FOR DSM PLANNING?**

5 A. Cost-effectiveness metrics using the cost tests described above often are
6 calculated at the measure, program, sector, and portfolio levels during DSM plan
7 design and development. This level of detail gives program administrators the best
8 available information to craft a portfolio plan that achieves and balances
9 competing objectives. Screening for implementation and compliance in the TRC
10 test is most commonly completed at the program or portfolio level. This allows for
11 certain measures or programs to be implemented with a TRC test ratio below 1.0 if
12 the aggregated benefits and costs at the compliance screening level achieves a
13 cost-effective result. There are several reasons for the aggregation of costs and
14 benefits at the program or portfolio level for screening purposes. In my
15 experience:

- 16 • Program level and portfolio levels are best for assessing overall net
17 benefits, monitoring changes in program effectiveness, and for evaluating
18 performance.
- 19 • Cost and savings algorithms used in benefit-cost analysis frameworks
20 necessarily use average values. It is understood that individual customer or
21 building costs and savings will be different, even unique. Screening at the
22 measure level introduces false precision.

- Cost tests were designed with program aggregation in mind. This is reflected in the NSPM and associated training material for program administrators. Measure-level screening is usually done in the course of energy efficiency potential studies where administrative costs are excluded. Even in this case, most potential studies relax or remove measure-level screening thresholds when presenting achievable potential.
- Program and portfolio administrative costs are difficult or impossible to precisely allocate to measures depending on the operation of the program. Weighted average allocations may not reflect the true cost to administer individual measures within a program, and there is no broadly agreed upon basis for the weighting.
- Targeted programs like low income or small business are often exempted from screening. This allows for equity concerns to be addressed, and for deeper savings to be pursued. In these cases, the portfolio as a whole should still be required to pass cost effectiveness screening.

Q. IS EFFICIENCYONE’S SCREENING LEVEL CONSISTENT WITH LEADING JURISDICTIONS COST-EFFECTIVENESS METHODOLOGIES?

- A. Yes. EfficiencyOne screens at the program level, allowing specific measures in the plan to not pass the TRC test if the aggregated program benefits and costs achieve cost-effective results. Variable and fixed program administrative

1 costs are allocated to the measures for informational purposes when calculating
2 measure-level TRC test metrics. This is consistent with best practices in DSM plan
3 screening methodologies. The IESO Cost Effectiveness Guide for Energy
4 Efficiency Version 4 notes that program-level aggregation is typically used for
5 evaluation activities and that the addition of portfolio-level administrative costs
6 and screening is also important for year-over-year performance tracking.¹² Of the
7 47 US states with screening criteria, only six use the measure level for
8 compliance. All other states screen at the program or portfolio level, or a
9 combination of both.¹³

10
11 **Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

12 A. Yes, it does.

13

¹² IESO Cost Effectiveness Tests Guide for Energy Efficiency V4, January 2021.

¹³ Database of State Efficiency Screening Practices. <https://www.nationalenergyscreeningproject.org/state-database-dsp/database-of-state-efficiency-screening-practices/>

**Supply Agreement for
Electricity Efficiency and Conservation Activities**

Between

Nova Scotia Power Incorporated

and

EfficiencyOne

Effective Date – January 1, 2023

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DRAFT

1 **THIS AGREEMENT** made as of the ____ day of ____, 2022 and effective as of the 1st day
2 of January, 2023 (the “**Effective Date**”).

3 BETWEEN:

4 **NOVA SCOTIA POWER INCORPORATED,**
5 a body corporate, organized under the laws
6 of the Province of Nova Scotia

7
8 (hereinafter called “**NSPI**”)

9 - and -

10 **EFFICIENCYONE,**
11 a body corporate, organized under the laws of
12 Canada

13
14 (hereinafter called “**EfficiencyOne**”)

15 **WHEREAS:**

- 16 A. EfficiencyOne and NSPI are both public utilities pursuant to the Act; and
- 17 B. Pursuant to the Act, EfficiencyOne has the exclusive right to supply NSPI with
18 reasonably available, cost-effective Electricity Efficiency and Conservation Activities as
19 the Franchise Holder; and
- 20 C. Pursuant to the Act, NSPI is obligated to undertake cost-effective Electricity Efficiency
21 and Conservation Activities that are reasonably available in an effort to reduce costs for
22 its customers; and
- 23 D. Pursuant to the Act, NSPI shall meet its obligations by entering into an agreement with
24 the Franchise Holder for the supply of cost-effective Electricity Efficiency and
25 Conservation Activities.

26 **NOW THEREFORE** witnesses that in consideration of the premises and the mutual covenants
27 and obligations herein and other good and valuable consideration, the sufficiency and receipt of
28 which are hereby acknowledged, the parties agree as follows:

29 **1. INTERPRETATION**

30 1.1 The following terms shall be interpreted as follows in this Agreement:

- 31 (a) “**Act**” shall mean the *Public Utilities Act*, R.S.N.S. 1989, c.380, as amended from
32 time to time.
- 33 (b) “**Agreement**” means this agreement between NSPI and EfficiencyOne including
34 all Schedules attached hereto.
- 35 (c) “**Business Day**” means Monday to Friday, except federal, provincial, and civic
36 holidays within the Province of Nova Scotia.

- (d) **“Consequential Losses”** means consequential, special, incidental, multiple, exemplary or punitive damages including lost profits, whether such claim of lost profits is categorized as indirect, direct or consequential damages or under any alternative theory of recovery.
- (e) **“Contract Documents”** means without limitation, the following documents, including any amendments thereto agreed in writing by the parties:
- (i) this Agreement; and
 - (ii) all Schedules to the Agreement.
- (f) **“Contract Price”** has the meaning ascribed to it in Section 4.1.
- (g) **“EECA Plan”** means the plan prepared by EfficiencyOne and approved by the UARB and attached hereto as Schedule “E”.
- (h) **“Electricity Efficiency and Conservation Activities”** or **“EECA”** means the electricity efficiency and conservation activities as identified in Schedule “A” attached hereto.
- (i) **“Event of Default”** has the meaning ascribed to it in Section 20.4.
- (j) **“Environmental Laws”** means all applicable federal, provincial, regional, municipal or local laws with respect to environmental matters contained in the statutes, regulations, rules, standards, requirements, ordinances, policies, guidelines, orders, approvals, notices, permits or directives having the force of law, in effect as at the date hereof and as may be brought into effect at future date.
- (k) **“Force Majeure Event”** means any event or circumstance not reasonably within the control of the Party affected which wholly or partly prevents the performance by that Party of its obligations under this Agreement, provided that such Party is in good faith unable to perform such obligations by any commercially reasonable substitute. A Force Majeure Event includes acts of God, war, riot, fire, explosion, flood, hurricane, epidemics, acts of governmental authorities, acts of terrorism. Notwithstanding anything else contained herein, a Force Majeure Event excludes (a) any event or circumstance causing direct or indirect delay in, or failure to perform any of a Party’s obligations under this Agreement, attributable to a lack of reasonable diligence on the part of a Party or on the part of any vendor or subcontractor of a Party, including any event or circumstance which a Party or any vendor or subcontractor, acting diligently, could reasonably have been expected to foresee, avoid or overcome in the performance of its obligations; and (b) any event or circumstance caused by the breach of a Party’s obligations or the fault or negligence of a Party or the fault or negligence of any vendor or subcontractor, or by violation of applicable laws or regulations by a Party or any of a Party’s vendors or subcontractors. For certainty, adverse weather of any kind other than events specified above shall not be considered a Force Majeure Event.
- (l) **“Franchise”** has the meaning ascribed to it in the Act.
- (m) **“Franchise Holder”** has the meaning ascribed to it in the Act.

- (n) **"Governmental Authority"** means any federal, provincial, regional, municipal or local government or authority or other political subdivision thereof and entity or person exercising executive, legislative, judicial, regulatory or administrative functions of, or pertaining to, government.
- (o) **"Hazardous Substances"** means any substance or material that is prohibited, controlled or regulated by any Governmental Authority pursuant to Environmental Laws, including any contaminants, pollutants, petroleum or other hydrocarbons and their derivatives and by-products, dangerous substances or goods, including asbestos, liquid wastes, special wastes, toxic substances, hazardous or toxic chemicals, hazardous wastes, hazardous materials or hazardous substances as defined in or pursuant to any Environmental Law, or any substance or material not inherently hazardous but which would, in sufficient quantities, be hazardous.
- (p) **"Indemnified Costs"** means all liabilities, claims, actions, causes of action, judgments, orders, damages, costs (including those incurred in connection with any investigation of site conditions or any clean-up, environmental remediation, removal or restoration work), expenses (including all reasonable consultant, expert and legal fees and expenses), fines, penalties, losses, or any resulting damages, harm or injuries to the person or property of any third parties or to any natural resources and for which the indemnified party is liable and has incurred losses. Without limiting the foregoing, Indemnified Costs shall include:
- (i) the costs of defending and/or counterclaiming or claiming over and against third parties in such manner as the indemnified party in its sole discretion may determine;
 - (ii) the costs relating to any governmental investigation, proceeding or claim; and
 - (iii) any costs, liabilities or damages arising out of a settlement of a claim by the indemnified party, with or without the consent of the indemnifying party.
- (q) **"Law"** means the common law, the law of equity and all federal or provincial statutes or municipal by-laws and all regulations, orders, directives, permits and licenses thereunder, which apply to or otherwise affect NSPI or EfficiencyOne with respect to the supply of the EECA, or the property of NSPI or EfficiencyOne, real or personal, or any part thereof, including the Act and all environmental, occupational, health and safety laws.
- (r) **"Liens Indemnities"** has the meaning ascribed to it in Section 18.1.
- (s) **"Liens and Claims"** has the meaning ascribed to it in Section 18.1.
- (t) **"Minister"** has the meaning ascribed to it in the Act.
- (u) **"Party"** means either EfficiencyOne or NSPI. **"Parties"** means EfficiencyOne and NSPI.
- (v) **"Personal Information"** shall mean the information provided by NSPI to EfficiencyOne pursuant to Section 79K of the Act.

- (w) **"Release"** or **"Released"** means a releasing, adding, spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, migrating, dispersing, dispensing, disposing or dumping.
- (x) **"Significant Changes"** means any proposed change to the EECA Plan for which the UARB orders or directs EfficiencyOne to obtain the approval of the UARB prior to the implementation of such proposed change.
- (y) **"Subcontractor"** means any contractor, supplier or consultant hired by EfficiencyOne in accordance with this Agreement to perform any portion of the EECA.
- (z) **"Term"** has the meaning ascribed to it in Section 2.1.
- (aa) **"UARB"** means the Nova Scotia Utility and Review Board.
- (bb) **"CASL"** means An Act to promote the efficiency and adaptability of the Canadian economy by regulating certain activities that discourage reliance on electronic means of carrying out commercial activities, and to amend the Canadian Radio-television and Telecommunications Commission Act, the Competition Act, the Personal Information Protection and Electronic Documents Act and the Telecommunications Act, S.C. 2010, c. 23, as amended from time to time.
- 1.2 Unless otherwise specified in this Agreement or unless the context otherwise requires:
- (a) words of any gender include each other gender;
- (b) using the singular or plural number also include the plural or singular number, respectively;
- (c) the insertion of headings in this Agreement is for convenience only and shall not be construed so as to affect the interpretation or construction of this Agreement;
- (d) the terms "hereof," "herein," "hereto," "hereunder" and words of similar or like import refer to this entire Agreement and not to any particular Section, Schedule or other subdivision of this Agreement;
- (e) references to a particular "Section" or "Schedule" are, unless otherwise noted, references to that Section of, or Schedule to this Agreement;
- (f) the words "include," "includes" and "including" shall be deemed to be followed by "without limitation" or "but not limited to";
- (g) references to any applicable law, legislation or regulation shall be construed as a reference to such law, legislation or regulation as each may be in effect from time to time;
- (h) references to any agreement or document (including this Agreement) shall (i) include all Schedules, appendices, and other attachments thereto, and (ii) be construed at the particular time as a reference to such agreement or document as amended, modified or supplemented and in effect from time to time and shall include a reference to any document which amends, modifies or supplements it, or is entered into, made or given pursuant to or in accordance with its terms;

- (i) references to (i) days shall refer to calendar days unless Business Day is specified, (ii) weeks and months shall refer to calendar weeks and months, respectively, and (iii) years shall refer to calendar years;
- (j) in computing any period of time prescribed or allowed under this Agreement, the day of the act, event or default from which the designated period of time begins to run shall be included. If the last day of the period so computed is not a Business Day, then the period shall run until the close of business on the next Business Day;
- (k) the Contract Documents are complementary, and what is required by any one shall be as binding as if required by all;
- (l) words and abbreviations which have well known technical or trade meanings are used in the Contract Documents in accordance with such recognized meanings; and
- (m) as both Parties were actively involved in preparing the terms and conditions of this Agreement and as they both had access to and relied upon counsel in this process, there shall be no presumption that any one or the other Party prepared this Agreement and no provision of this Agreement shall be construed against either Party based upon the process of preparation of proposals and drafts of the Agreement.

1.3 If there is a conflict within the Agreement, the order of precedence of documents, from highest to lowest, shall be:

- (a) Sections 1 to 27;
- (b) Schedule “A” – Electricity Efficiency and Conservation Activities; and
- (c) all other Schedules.

2. TERM & RESERVATION OF RIGHTS

2.1 The term of this Agreement shall be three (3) years from the Effective Date and shall automatically terminate on December 31, 2025 unless terminated earlier in accordance with the terms of this Agreement and the Act (the “Term”).

2.2 During the Term, NSPI shall purchase from EfficiencyOne and EfficiencyOne shall supply to NSPI, the EECA in accordance with the terms and conditions of this Agreement and the Act.

2.3 Notwithstanding anything contained herein, and subject to any requirement for review or approval by the UARB, nothing contained in this Agreement shall in any way effect the rights of NSPI pursuant to Section 79I(3) of the Act.

3. ELECTRICITY EFFICIENCY and CONSERVATION ACTIVITIES

3.1 For the Term of this Agreement, EfficiencyOne will,

- (a) provide the EECA in accordance with this Agreement;

- (b) provide sufficient resources to enable EfficiencyOne to perform its obligations on time and in accordance with this Agreement;
- (c) carry out the EECA in a professional, expeditious and economical manner, in accordance with the Act;
- (d) manage the EECA in an efficient manner; and
- (e) perform and supply the EECA in a safe and environmentally sound manner and in compliance with applicable Law.

3.2 The Parties acknowledge and agree that EfficiencyOne shall be solely responsible for the delivery of the EECA Plan. For greater certainty and notwithstanding the attachment of the EECA Plan as Schedule “E” – Approved EECA Plan, NSPI shall have no liability with respect to the EECA Plan saving and excepting any liability which may arise as a result of NSPI’s failure to comply with the Act.

4. PRICE & PAYMENT

4.1 NSPI agrees to pay EfficiencyOne for EECA as set out in Schedule “B” – Compensation (the “**Contract Price**”).

4.2 The Contract Price shall constitute full compensation for the EECA, and no additional compensation shall be payable to EfficiencyOne arising out or resulting from any productivity losses, overhead or indirect costs or other costs and expenses of any kind whatsoever.

4.3 NSPI shall make monthly payments on the first Business Day of each month in accordance with Schedule “B” to EfficiencyOne on account of the Contract Price when due, together with applicable HST. EfficiencyOne will submit an invoice to NSPI in advance of the payment date referenced in Schedule “B”.

4.4 Unless otherwise indicated all dollar amounts referred to in this Agreement are in lawful money of Canada.

4.5 If applicable, payments shall be subject to harmonized sales tax (as defined in the *Excise Tax Act* (Canada)) (“**HST**”). No additional taxes (foreign or domestic), customs, duties or brokerage fees shall apply.

4.6 If applicable, NSPI will withhold from payments to EfficiencyOne any amounts required to be withheld under applicable Laws and treaties in respect of services rendered in Canada by a non-resident and may remit them to the relevant authority. Where available, statutory withholding may be waived if EfficiencyOne delivers to NSPI a formal waiver of the withholding requirement issued and signed by Canada Revenue Agency. The Parties shall cooperate at all times to ensure that all proper withholdings are deducted from payments and if any withholdings are overlooked then such withholdings may be deducted from later payments.

5. NOTIFICATION OF SIGNIFICANT CHANGES

5.1 EfficiencyOne shall provide notice of Significant Changes to NSPI at the same time as EfficiencyOne makes application to the UARB for the approval of the Significant Changes. Subject to the terms of the Act and the general discretion of the UARB under

the Act, NSPI shall, have the right to make written submissions to the UARB on any such Significant Changes to the EECA Plan.

6. SAFETY

6.1 EfficiencyOne shall at all times be responsible for safety and loss management in the supply or performance of the EECA.

6.2 EfficiencyOne shall ensure that all employees, Subcontractors, agents and representatives of EfficiencyOne comply with all federal, provincial and municipal health, safety and environmental statutes, regulations, policies and guidelines and all health, safety and environmental rules as prescribed by EfficiencyOne.

7. PROTECTION OF PROPERTY

7.1 EfficiencyOne shall take all commercially reasonable steps to protect the property of NSPI's customers and other third parties from damage which may occur as the result of the performance of the EECA.

7.2 Should EfficiencyOne damage the property of NSPI's customers or property of other third parties while performing the EECA, EfficiencyOne shall make good such damage at EfficiencyOne's expense and shall indemnify NSPI from and against all liabilities, claims, damages, settlements, awards, costs, expenses and proceedings incurred by NSPI or its servants, employees and/or agents in respect of such damage, except to the extent such damage occurs as a result of the negligent acts of NSPI or those for which NSPI is responsible at Law.

8. ENVIRONMENT

8.1 EfficiencyOne and its Subcontractors shall at all times comply with all Environmental Laws that apply in any way to the supply or performance of the EECA. EfficiencyOne and its Subcontractors shall not cause, permit or suffer the Release of a Hazardous Substance in contravention of any Environmental Laws.

8.2 Notwithstanding any other provision in this Agreement (and in addition to any other right to indemnity held by NSPI under the terms of the Agreement) EfficiencyOne shall indemnify NSPI, NSPI's parent, their respective subsidiaries, affiliates and related companies, and their respective officers, directors, employees, agents and shareholders, and agrees to hold each of them harmless from and against any and all Indemnified Costs resulting from any Release of any Hazardous Substance which is caused or contributed to by EfficiencyOne or its Subcontractors or any breach of any Environmental Law by EfficiencyOne or its Subcontractors.

9. EFFICIENCYONE'S COVENANTS

9.1 EfficiencyOne warrants, covenants and agrees with NSPI that:

(a) it has all requisite capacity and authority to execute, deliver and perform its obligations under this Agreement;

(b) this Agreement has been duly and validly executed and delivered by EfficiencyOne and constitutes a legal, valid and binding obligation of EfficiencyOne enforceable against EfficiencyOne in accordance with its terms;

- (c) to its knowledge, there is no matter, thing or event, including without limitation, any litigation, proceeding, breach, default or financial circumstance that would adversely affect EfficiencyOne's ability to perform its obligations under this Agreement;
- (d) it will furnish all labour, materials, products, tools, and other necessary components necessary to perform and provide the EECA, unless otherwise provided herein;
- (e) it shall diligently perform or cause to be performed the EECA in a proper and workmanlike manner;
- (f) it has the skills, expertise and resources to carry out the EECA and to comply, observe and perform the obligations to which it is subject in accordance with the terms of this Agreement;
- (g) prior to commencing any work hereunder, it shall obtain and maintain all permits, licenses and notices that a prudent supplier acting in accordance with industry standards would be required to obtain, maintain and provide in comparable circumstances and shall comply with all applicable Laws, ordinances, rules, regulations, codes and orders of any and all authorities having jurisdiction which are or become in force during the Term in respect of the EECA;
- (h) it will comply with applicable federal, provincial and municipal statutes, regulations and bylaws pertaining to the EECA performed by or on behalf of EfficiencyOne under this Agreement. EfficiencyOne shall be responsible for ensuring similar compliance by any suppliers and Subcontractors;
- (i) it is the Franchise Holder pursuant to the Act;
- (j) it is not a non-resident of Canada for the purposes of the *Income Tax Act*;
- (k) it will execute or cause to be made, done and executed all further acts, deeds, assurances, agreements, instruments or other documents as may be reasonably required to ensure fulfillment of the terms of this Agreement;
- (l) the EECA shall be delivered and performed by individuals duly licensed and authorized by Law, if applicable, to perform said undertakings;
- (m) the EECA shall be delivered and performed solely by EfficiencyOne or its Subcontractors and EfficiencyOne acknowledges that EfficiencyOne shall at all times remain responsible for the proper completion of this Agreement; and
- (n) upon becoming aware of a potential disruption having a material impact in the supply of the EECA, EfficiencyOne shall provide notification to the UARB and NSPI.

10. SUBCONTRACTORS

- 10.1 EfficiencyOne shall be permitted to subcontract the performance of any part of the EECA without the prior written approval of NSPI.

10.2 Where EfficiencyOne subcontracts any part of the EECA, EfficiencyOne shall preserve and protect the rights of the Parties under this Agreement with respect to the EECA to be supplied or performed under subcontract, and shall be as fully responsible to NSPI for the acts and omissions of Subcontractors and of persons directly or indirectly employed by them, as if they were acts and omissions of persons directly employed by EfficiencyOne.

10.3 Nothing contained in the Contract Documents shall create a contractual relationship between a Subcontractor and NSPI.

11. CONFIDENTIAL AND PERSONAL INFORMATION

11.1 The Parties have executed or agree to execute the confidentiality agreement attached hereto as Schedule “D” - Confidentiality (“**Confidentiality Agreement**”).

11.2 EfficiencyOne shall be responsible for all physical and electronic security required to ensure the security of the Personal Information which has been provided by NSPI to EfficiencyOne.

11.3 EfficiencyOne shall indemnify and hold harmless NSPI for any liabilities, claims, damages, settlements, awards, costs, expenses and proceedings incurred by NSPI or its servants, employees and/or agents in consequence of EfficiencyOne’s misuse of the Personal Information or any disclosure, whether intentional, inadvertent, negligent or otherwise of any of the Personal Information by EfficiencyOne contrary to the terms of this Agreement or the Act, or in consequence of EfficiencyOne’s contravention of CASL.

12. PERFORMANCE REQUIREMENTS AND EVALUATIONS

12.1 EfficiencyOne’s performance under the terms of this Agreement shall be measured in accordance with the performance requirements established by the UARB pursuant to Section 79M of the Act as set out in Schedule “C” – Performance Requirements.

13. FORCE MAJEURE

13.1 Neither Party shall be in breach of its obligations under this Agreement where failure to perform or delay in performance of any obligation is due, wholly or in part, to a Force Majeure Event.

13.2 Each Party shall notify the other Party promptly of any Force Majeure Event and shall take reasonable steps to minimize the impact of the failure or the delay and to resolve the event or occurrence that has given rise to the Force Majeure Event in order to resume performance. The time for performing an obligation as a result of Force Majeure Event shall be extended for the period lost, subject to the condition that the Term of this Agreement shall not be extended as a result of any Force Majeure Event.

13.3 Each Party suffering a Force Majeure Event shall take, or cause to be taken, such action as may be necessary to void, or nullify, or otherwise to mitigate, in all material respects, the effects of such Force Majeure Event. The Parties shall take all reasonable steps to ensure normal performance under this Agreement, including the resumption of any disrupted obligations.

13.4 For certainty, in no case shall the failure or omission of EfficiencyOne to carry out or observe any of the terms, provisions, or conditions of this Agreement or any negligent

act or omission of EfficiencyOne, or others for whom EfficiencyOne is responsible constitute an event of Force Majeure or result in an extension of the time to perform the EECA.

14. INDEMNITY

14.1 EfficiencyOne shall assume all risk of loss, damage or injury, including death, to person or property, caused by its directors, officers, employees, Subcontractors, agents or representatives, and agrees not to make or bring any claim, action or demand against NSPI or its directors, officers, servants, agents, or employees in respect of such loss, damage or injury excepting such loss, damage or injury caused by the negligence or wilful misconduct of NSPI or NSPI's directors, officers, servants, agents or employees.

14.2 EfficiencyOne agrees to indemnify and save harmless NSPI, its directors, officers, servants, agents, or employees, and their heirs, executors, administrators, successors and assigns, or any of them, from and against any liabilities, losses, expenses (including legal costs on a solicitor-client basis), claims, demands, actions, and causes of action, whatsoever suffered by NSPI by reason of, or in any way arising out of or in connection with a breach of this Agreement by EfficiencyOne excepting only to the extent caused by the negligence or wilful misconduct of NSPI or NSPI's directors, officers, servants, agents or employees.

14.3 NSPI agrees to indemnify and save harmless EfficiencyOne, its directors, officers, servants, agents, or employees, and their heirs, executors, administrators, successors and assigns, or any of them, from and against any liabilities, losses, expenses (including legal costs on a solicitor-client basis), claims, demands, actions, and causes of action, whatsoever suffered by EfficiencyOne by reason of, or in any way arising out of or in connection with a breach of this Agreement by NSPI excepting only to the extent caused by the negligence or wilful misconduct of EfficiencyOne or EfficiencyOne's directors, officers, servants, agents or employees.

14.4 The provisions set forth in this Section shall apply and be effective with respect to any claim, cause of action, or legal theory whatsoever including without limitation, claims based upon breach of contract, failure to meet performance guarantees, tort (including negligence) and strict liability.

14.5 EfficiencyOne shall defend, indemnify and hold harmless NSPI from any claim, suit, cause of action, judgment, cost or expense (including legal fees) based on a claim by a third party that any intellectual property which is part of the EECA or supply or performance of EfficiencyOne's obligations under this Agreement infringes any patent, copyright, trade secret or other intellectual property right, provided the EfficiencyOne is promptly notified of such claim and is given complete authority for defense of same. EfficiencyOne shall pay all damages, costs and expenses resulting from such a claim, including legal fees and settlement costs, but shall not be responsible for any cost, expense or compromise incurred by NSPI without EfficiencyOne's prior consent.

15. LIMIT OF LIABILITY

15.1 Neither Party shall be liable to the other Party for any Consequential Losses with respect to the performance or non-performance under this Agreement or for any actions undertaken in connection with or related to this Agreement.

15.2 EfficiencyOne's total liability to NSPI with respect to the performance or non-performance under this Agreement or for any actions undertaken in connection with or related to this Agreement shall be limited to the greater of the sum of two million dollars (\$2,000,000) or the proceeds of the applicable insurance policies taken out by EfficiencyOne under this Agreement ("**EfficiencyOne Limit of Liability**") provided that the EfficiencyOne Limit of Liability shall not apply to:

(a) indemnification of NSPI by EfficiencyOne under the terms of this Agreement for any third party claims (including but not limited to EfficiencyOne's obligations pursuant to Sections 7.2, 8.2, 11.3, 14.5 and 18.1);

(b) any wilful misconduct or fraud of EfficiencyOne or its employees, agents or representatives; and

(c) any obligation on the part of EfficiencyOne to refund in whole or in part the Contract Price pursuant to this Agreement or the Act.

15.3 NSPI's total liability to EfficiencyOne with respect to the performance or non-performance under this Agreement or for any actions undertaken in connection with or related to this Agreement shall be limited to the sum of two million dollars (\$2,000,000) ("**NSPI Limit of Liability**") provided that the NSPI Limit of Liability shall not apply to:

(a) any wilful misconduct or fraud of NSPI or its employees, agents or representatives; and

(b) NSPI's liability for payment of the Contract Price pursuant to the Agreement or the Act.

16. INSURANCE

16.1 EfficiencyOne shall obtain, maintain and pay for, during the entire Term of this Agreement, the following minimum insurance coverage as follows, such insurance as it relates to this Agreement shall be in a form and from an insurer acceptable to NSPI:

(a) General liability insurance shall be in the name of EfficiencyOne and shall name NSPI as an additional insured and shall have limits of not less than five million dollars (\$5,000,000) inclusive per occurrence for bodily injury, death, and damage to property including loss of use thereof. Such insurance shall be primary and non-contributing with, and not in excess of, any other insurance available to NSPI. This policy shall also contain cross liability and severability of interest and blanket contractual liability.

(b) Environmental impairment insurance with limits of not less than five million dollars (\$5,000,000);

(c) Automobile liability insurance in respect of licensed vehicles shall have limits of not less than two million dollars (\$2,000,000) inclusive per occurrence for bodily injury, death, and damage to property. For automobiles not owned or operated by or on behalf of EfficiencyOne the insurance shall be in the form of a standard non-owned automobile policy and shall include standard contractual liability endorsement. For automobiles owned or operated by or on behalf of EfficiencyOne the insurance shall be in the form of a standard owner's form automobile policy and shall provide third party liability and accident benefits

- 1 insurance covering licensed vehicles owned or operated by or on behalf of
2 EfficiencyOne.
- 3 (d) Property Insurance covering all loss of or damage to EfficiencyOne's property
4 and equipment of EfficiencyOne or for which EfficiencyOne is legally liable or
5 responsible used in performance of the EECA for the full replacement value,
6 which insurance shall not allow subrogation claims by the insurer against NSPI.
- 7 (e) To the extent that the EECA includes the provision of professional services,
8 professional liability errors and omissions insurance covering all claims arising
9 out of errors and omissions of EfficiencyOne in the performance of professional
10 services as part of the EECA with a limit of two million dollars (\$2,000,000). In
11 the event other claims erode EfficiencyOne's professional errors and omissions
12 insurance below two million dollars (\$2,000,000), in the annual aggregate,
13 EfficiencyOne agrees to reinstate the limit.
- 14 (f) Workers' compensation to the full extent required in Nova Scotia and wherever
15 EfficiencyOne's personnel contracts of employment are made or are expressed
16 to be made.
- 17 16.2 If EfficiencyOne fails to effect or keep in force any of the foregoing insurances, NSPI
18 may, without prejudice to any other right or remedy, effect such insurance and pay the
19 premiums due and recover the same as a deduction from any other monies due to
20 EfficiencyOne under this Agreement.
- 21 16.3 EfficiencyOne shall be responsible to pay deductible amounts and for determining the
22 deductible amount in respect of each policy. EfficiencyOne shall not violate, nor
23 knowingly permit to be violated, any conditions of the policies maintained according to
24 the provisions of this Section, and it shall be EfficiencyOne's duty and responsibility to
25 impose upon each Subcontractor the same responsibilities and obligations imposed
26 upon EfficiencyOne under such provisions.
- 27 16.4 EfficiencyOne agrees to provide proof of insurance to NSPI on an annual basis. Such
28 proof shall be in the form of a certificate of insurance signed by EfficiencyOne's
29 insurance broker.
- 30 **17. INTELLECTUAL PROPERTY**
- 31 17.1 NSPI acknowledges that all branding, trade and business marks of EfficiencyOne used
32 in the course of provision of EECA pursuant to this Agreement, (the "**EfficiencyOne
33 Brands**") are, and shall remain, the sole and exclusive property of EfficiencyOne and
34 shall not be used by NSPI without EfficiencyOne's express consent. Upon termination of
35 this Agreement, NSPI shall immediately upon instruction from EfficiencyOne return or
36 destroy, as instructed by EfficiencyOne, the EfficiencyOne Brands.
- 37 17.2 Any trademarks, brands, logos or other branding or trade or business marks used in
38 NSPI's business ("**NSPI Brands**") shall remain the sole and exclusive property of NSPI
39 and shall not be used by EfficiencyOne for any purpose except in connection and as
40 necessary for the provision of the EECA. Upon termination of this Agreement,
41 EfficiencyOne shall immediately upon instruction from NSPI return or destroy, as
42 instructed by NSPI, the NSPI Brands.

18. LIENS AND CLAIMS

18.1 EfficiencyOne shall indemnify and hold harmless NSPI, NSPI's parent and their subsidiaries and affiliates (collectively the "**Lien Indemnitees**" or singularly "**Lien Indemnitee**") and defend each of them from and against any and all losses and costs arising out of any and all claims for payment, liens, attachment or any other process, filed against any property of the Lien Indemnitees by or in respect of a Subcontractor of any tier or any other party providing work, materials in respect of the EECA or any part thereof (referred to in this Section as "**Liens or Claims**"), including solicitor and client fees and expenses incurred by NSPI in discharging any such Liens or Claims or similar encumbrances.

18.2 EfficiencyOne shall discharge promptly any Liens or Claims. If EfficiencyOne does not promptly satisfactorily discharge such Liens or Claims, NSPI at its sole option may (i) require EfficiencyOne to pay, within five (5) Business Days after request by NSPI, or (ii) subject to any requirements of the *Builders' Lien Act* of Nova Scotia, offset against any holdback or other amounts due or to become due to EfficiencyOne, all costs and expenses incurred by NSPI or other Lien Indemnitee in causing the release of, paying or settling such Liens or Claims. EfficiencyOne shall have the right to contest any such Liens or Claims, provided it first provides to NSPI a bond or other assurance of payment reasonably satisfactory to NSPI in the amount of such Liens or Claims and in form and substance reasonably satisfactory to NSPI. In no circumstance whatsoever shall NSPI be liable for a greater amount than the amount payable by NSPI to EfficiencyOne.

19. DISPUTE RESOLUTION

19.1 In the event of a dispute in connection with this Agreement, a senior representative of EfficiencyOne and a senior representative of NSPI shall promptly meet to discuss and resolve the dispute and the Parties shall have thirty (30) days to resolve the dispute (or ten (10) days if either Party notifies the other Party that the matter requires urgent resolution).

19.2 Unless the parties agree otherwise, in the event resolution cannot be achieved in accordance with Section 19.1 of this Agreement, then such dispute or difference shall be referred to the UARB in accordance with Section 79P of the Act.

19.3 Notwithstanding any dispute, EfficiencyOne shall diligently carry out the EECA, and shall not suspend, impair, interfere with, restrict or discourage the prompt completion of any portion of the EECA, unless specifically authorized to do so by the UARB. .

20. DEFAULT AND TERMINATION

20.1 This Agreement may be terminated immediately by either Party, in whole or in part, upon the happening of one or more of the following events:

(a) EfficiencyOne's Franchise is terminated and the Agreement has not been assigned by the Minister; or

(b) The UARB approves the termination of the Agreement.

In the event of a termination pursuant to this Section 20.1, neither Party shall be entitled to any compensation or damages for any Consequential Losses as a result of such termination. Immediately upon receipt of such termination notice, EfficiencyOne will

discontinue all EECA under this Agreement and will only finish such portions of the EECA as may be necessary to preserve and protect the EECA already in progress. Such termination does not relieve either Party from any of their respective obligations under this Agreement for EECA provided up to the date of termination. Any claim for payment by EfficiencyOne must be asserted within thirty (30) days from the date of such termination.

20.2 Notwithstanding any other provision in this Agreement, in the event this Agreement is terminated in accordance with Section 20.1(a), EfficiencyOne shall:

- (a) Immediately return all monies paid on account of the Contract Price which amounts have not been legitimately incurred or subject to contractual commitments for expenditure which cannot otherwise be mitigated to NSPI; and
- (b) Provide to NSPI all reasonable required termination assistance to allow the EECA provided under this Agreement to continue and to facilitate the orderly transition of the EECA to NSPI or any third party as directed by NSPI, provided that EfficiencyOne shall be entitled to commercially reasonable payment for such transition services on a time and material basis.

20.3 The Parties acknowledge that this Agreement is subject to the general supervision of the UARB.

20.4 A Party shall be determined to be in default of its obligations under this Agreement if (each a “**Event of Default**”):

- (a) it is in breach of any material term or condition of this Agreement, which breach is not cured by the Party within thirty (30) days after written notice from the other Party;
- (b) it assigns this Agreement other than as permitted by the Act and/or the UARB;
- (c) any representation or warranty made by either Party shall prove to be untrue when made in any material respect;
- (d) there is a sale, transfer or relinquishment, voluntary or involuntary, by operation of law or otherwise, of legal control of the business of either Party except for a transfer to a related corporation or a transfer resulting from a merger, acquisition, amalgamation or reorganization, or, in the case of EfficiencyOne, a change in the Membership of the corporation;
- (e) Either Party sells, transfers or assigns all or substantially all of its assets;
- (f) a petition in bankruptcy is filed with respect to either Party; or
- (g) any proceeding is commenced under any bankruptcy or insolvency legislation or under any other federal, state or provincial law relating to insolvency or bankruptcy, the adjudication of either Party as a bankrupt, the appointment by any competent court having jurisdiction of a temporary or permanent receiver, trustee or other officer having similar powers over either Party its business or assets, or the making of any assignment by either Party for the benefit of its creditors.

20.5 If a breach notified pursuant to Sections 20.4(a) cannot be corrected within the period required therein, the defaulting Party shall not be in breach or violation if it:

(a) commences and diligently and continuously carries out the correction of the breach or violation within the specified time;

(b) provides to the non-defaulting Party, and the UARB an acceptable plan for such correction; and

(c) corrects the breach or violation in accordance with such plan.

20.6 Upon the occurrence of an Event of Default, the non-defaulting Party may apply to the UARB to terminate this Agreement in whole or in part.

21. NOTIFICATIONS

21.1 All notices to be given to either Party under this Agreement shall be written and addressed to the NSPI and to EfficiencyOne as follows:

To NSPI:

Nova Scotia Power Incorporated
1223 Lower Water Street
PO Box 910
Halifax, NS B3J 3S8
Attention: Corporate Secretary
Facsimile: (902) 428-6171

To EfficiencyOne:

EfficiencyOne
230 Brownlow Avenue
Suite 300
Dartmouth, NS B3B 0G5
Attention: CEO
Facsimile: (902) 470-3599

21.2 All notices may be sent by facsimile, a nationally recognized overnight courier service, first class mail or hand delivered. Notice shall be given when received by the addressee on a Business Day. In the absence of proof of the actual receipt date, the following presumptions will apply:

(a) Notices sent by facsimile shall be presumed to have been received upon the sending Party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is not a Business Day or is after five p.m. (local time for the recipient) on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day.

(b) Notice by overnight courier shall be presumed to have been received on the next Business Day after it was sent.

(c) Notice by first class mail shall be presumed delivered five (5) Business Days after mailing.

21.3 Either Party may modify its address for notices by advance written notice to the other Party.

22. AUDIT AND INSPECTION

22.1 EfficiencyOne shall, during the Term and for a period of thirty-six (36) months thereafter, keep accurate records of all EECA supplied to NSPI, as necessary to determine that the EECA was provided in accordance with the terms and conditions of this Agreement.

22.2 NSPI shall have the right to apply to the UARB to request access to any of the records referred to in 22.1.

22.3 NSPI shall have the right to apply to the UARB to inspect or observe the EECA at all times, whether using its own forces or those of a designated third party. EfficiencyOne shall facilitate such inspections and provide sufficient, safe and proper facilities at all times for inspection of the EECA.

23. ASSIGNMENT

23.1 Neither Party shall assign all or any portion of this Agreement without the prior written approval of the UARB and/or the Minister as the situation requires.

24. SHARING OF DATA AND INFORMATION

24.1 EfficiencyOne shall work co-operatively with NSPI to provide NSPI with information and data from time to time in order to assist NSPI with planning and load forecasting as may be reasonably required by NSPI. For greater certainty, such information and data shall be consistent with the past practices of the Parties.

24.2 In the event of a dispute regarding any request for information by NSPI, NSPI shall have the right to apply to the UARB to request access to the information and data referred to in 24.1.

25. COORDINATION MEETINGS AND REPORTS

25.1 During the Term of this Agreement, EfficiencyOne shall prepare and deliver to the UARB and NSPI a quarterly report (the “**Quarterly Report**”) in a form acceptable to the UARB.

25.2 EfficiencyOne shall prepare and deliver to the UARB and NSPI an annual report (the “**Report**”) in a form acceptable to the UARB. For greater certainty, the Report shall summarize and provide details as to the EECA and milestones achieved in the prior year, contain a discussion and analysis of major discrepancies relative to the EECA Plan’s intent and forecasts, EfficiencyOne’s financial statement for the previous year with respect to the EECA, evaluation reports and a summary of planned versus actual savings and costs for each metric.

1 25.3 The Parties agree that ongoing coordination and regular communication between NSPI
2 and EfficiencyOne is important in order to ensure effective planning. To that end, the
3 Parties shall meet quarterly or as otherwise agreed upon to discuss the provision of the
4 EECA.

5 **26. GENERAL**

6 26.1 This Agreement shall only be renewed in accordance with the provisions of the Act.

7 26.2 This Agreement shall extend to, be binding upon and enure to the benefit of the
8 respective successors and permitted assigns of the Parties hereto.

9 26.3 EfficiencyOne will be an independent contractor. EfficiencyOne shall not act as an agent
10 for NSPI, bind NSPI to any obligation with a third party, nor hold itself out as having
11 authority to bind or obligate NSPI. None of the persons engaged by EfficiencyOne or
12 any of its Subcontractors in the performance of the EECA will be considered employees
13 of NSPI.

14 26.4 This Agreement shall be deemed to have been made in and shall be governed by,
15 construed and interpreted in accordance with the laws of the Province of Nova Scotia
16 and the laws of Canada, as applicable therein. Where the provisions of this Agreement
17 or the Act permit or require a matter to be referred to or proceeded with before a court,
18 or in any other case where the Parties bring a matter in respect of this Agreement before
19 a court, the Parties irrevocably attorn to the jurisdiction of the Supreme Court of Nova
20 Scotia.

21 26.5 No consent or waiver, express or implied, by any Party to this Agreement of any breach
22 or default by any other Party in the performance of its obligations under this Agreement
23 or of any of the terms, covenants or conditions of this Agreement shall be deemed or
24 construed to be a consent or waiver of any subsequent or continuing breach or default in
25 such Party's performance.

26 26.6 Time shall be of the essence for purposes of this Agreement.

27 26.7 This Agreement, upon approval by the UARB, shall represent the entire Agreement
28 between the Parties with respect to the subject matter hereto and shall not be modified,
29 varied or amended except by an instrument in writing signed by the Parties and
30 approved by the UARB or as ordered or directed, by the UARB at any time.

31 26.8 Should any provision of the Agreement be declared by a judicial or other competent
32 authority to be unenforceable, the remaining provisions of the Agreement shall remain in
33 full force and effect.

34 26.9 The Parties acknowledge that this Agreement and all related documents shall be in
35 English.

36 26.10 This Agreement may be executed by the Parties in counterparts, each of which when so
37 executed and delivered shall be deemed to be an original and when taken together shall
38 be deemed to be one and the same instrument. The electronic delivery, including,
39 without limitation, by email or facsimile transmission, of any signed original of this
40 Agreement shall be the same as the delivery of an original.

27. SURVIVAL

27.1 Subject to the provisions of the Act, all provisions of this Agreement which by their express terms or nature are continuing shall survive the expiration or termination of this Agreement, including, without limitation, this provision, and the provisions relating to the EECA Plan (s. 3.2), EfficiencyOne's covenants (s.9), confidentiality (s. 11), indemnity (s.14), intellectual property (s. 17), notification (s. 21) and general provisions (s. 26) as well as any provisions which are required to determine, or which exclude or limit, any liability or which are otherwise required to give effect to or interpret any such provisions which are continuing.

[Remainder of page intentionally left blank]

1 **IN WITNESS THEREOF**, the Parties have duly executed this Agreement, in duplicate, as of the
 2 date set forth above.

	}	NOVA SCOTIA POWER INCORPORATED
		Per: _____
_____		Name: _____
Witness		Title: _____
_____	}	Per: _____
Witness		Name: _____
		Title: _____
	}	EFFICIENCYONE
		Per: _____
_____		Name: _____
Witness		Title: _____
_____	}	Per: _____
Witness		Name: _____
		Title: _____

3

4

SCHEDULE A**ELECTRICITY EFFICIENCY AND CONSERVATION ACTIVITIES****Schedule A****Electricity Efficiency and Conservation Activities**

The figure below identifies the scope of savings (3 year Cumulative Annual Energy Savings and Cumulative Annual Peak Demand Savings) associated with carrying out EECAs over the Term.

	Cumulative Annual Net Energy Savings at Generator over the Term (GWh)	Cumulative Annual Net Peak Demand Savings at Generator over the Term (MW)	
Performance Targets*			

The Performance Targets will be achieved in accordance with the EECA Plan as set out in Schedule E.

* For certainty, in accordance with the performance requirements set out in Schedule "C" attached hereto, EfficiencyOne shall be deemed to be in substantial compliance with the approved Performance Targets if the stipulated 90 percent level of achievement is reached on each Performance Targets. If less than the stipulated 90 percent level any of the Performance Targets is achieved, a regulatory process will be triggered.

**

SCHEDULE B**COMPENSATION****Schedule B (Page 1 of 2)****Compensation****I. Net Contract Price**

The figure below identifies the Contract Price to be paid by NSPI allocated for each year of the Term.

		2023	2024	2025
UARB Approved Investment Amount				
2020 – 2022 DSM Plan Underspend				
Net Contract Amount to be Paid by NSPI				

The Parties acknowledge that any surplus realized by EfficiencyOne in delivering the Performance Targets at the end of the Term shall be reported to the UARB and refunded to NSPI¹ unless EfficiencyOne is directed to do otherwise by the UARB.

¹ Together with all accumulated interest earned by EfficiencyOne on such surplus.

Schedule B (Page 2 of 2)**Compensation****II. Payments**

In accordance with Section 4.3 of the Agreement, the monthly payments to be made by NSPI to EfficiencyOne over the Term shall be as set out below. The monthly payment amounts referred to following are exclusive of required HST. HST shall be remitted to EfficiencyOne in addition to these monthly amounts.

On the First Business Day of:	2023	2024	2025
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
Total			

SCHEDULE C**Performance Requirements****I. UARB-APPROVED PERFORMANCE TARGETS, THRESHOLDS, AND INDICATORS****a) Performance Targets and Thresholds:**

- i. Performance Targets are set over the three year contract period, rather than annually.
- ii. EfficiencyOne is deemed to be in substantial compliance with the UARB-approved Plan Performance Targets if ninety percent (90%) or greater achievement is reached on the cumulative annual net energy savings at generator and cumulative net peak demand savings at generator Performance Targets listed at b) i and ii below. If less than ninety percent (90%) of either Performance Target at b) i and ii below is achieved, a regulatory process will be triggered.

b) Performance Targets consist of:

- i. Cumulative annual net energy savings at generator
- ii. Cumulative annual net peak demand savings at generator

c) Performance Indicators (for UARB reporting) consist of:

- i. Annual incremental energy savings (reported by program and rate class);
- ii. Cumulative annual energy savings (reported by program and rate class);
- iii. Annual lifetime energy savings (reported by program and rate class);
- iv. Cumulative lifetime energy savings (reported by program and rate class);
- iv. Annual incremental system-peak demand savings (reported by program and rate class);
- v. Cumulative annual system-peak demand savings (reported by program and rate class);
- vi. Annual demand savings attributable to demand response activities
- vi. Total ratepayer benefits;
- vii. Total spending (reported by program and rate class);
- viii. Customer satisfaction; and

87 x.Reporting on low-income program participation, expenditures, and savings
88 through a variety of methods, including estimation based on geographic
89 census information.
90
91

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SCHEDULE D**CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT**

THIS CONFIDENTIALITY AGREEMENT made effective this 1st day of January, 2023

Between:

EfficiencyOne, hereinafter “EfficiencyOne”

Party of the First Part

And

Nova Scotia Power Incorporated, hereinafter “NSPI”

Party of the Second Part

Whereas the Parties have entered into a Supply Agreement for Electricity Efficiency and Conservation Activities made effective as of January 1, 2023 (“Supply Agreement”) whereby Efficiency One is to provide EECA (as that term is defined in the Supply Agreement) to NSPI;

And whereas in accordance with the Supply Agreement, and the Electricity Efficiency and Conservation Act (Nova Scotia) and the Public Utilities Act (Nova Scotia) (together hereinafter referred to as the “Legislation”), and as may be directed by the Nova Scotia Utility and Review Board, and as may be further agreed between the Parties, the Parties will be receiving, reviewing, and analyzing Confidential Information from each other;

And whereas the Parties wish to clarify the manner in which any Confidential Information disclosed by one Party (“Disclosing Party”) to the other is to be treated by the recipient of the Confidential Information (“Recipient”);

In consideration of the agreements of the Parties set forth below, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

Confidential Information

1. The Parties agree that for the purpose of this Agreement "Confidential Information" means all information, regardless of the form in which it is communicated or maintained and prepared by the Disclosing Party, and is disclosed directly or indirectly to the Recipient, pursuant to the Supply Agreement, the Legislation, as directed by the Nova Scotia Utility and Review Board or as otherwise agreed between the Parties. Confidential Information includes, but is not limited to the following: all reports analyses, notes, memoranda, correspondence, spreadsheets, drawings, survey plans, maps, contracts, commercial arrangements, intellectual property, trade secrets, corporate strategies, business plans or other information that is based on, contain or reflect any Confidential Information, material, whether printed or electronic, which has been designated by the Disclosing Party as confidential information, including proprietary information and other commercially sensitive information. This includes but is not limited to information which has been or may be filed with the Nova Scotia Utility and Review Board ("the Board") in confidence in answer to Information Requests and any further material that may be filed with the Board in confidence whether in response to future Information Requests or otherwise, and whether printed or electronic. Confidential Information shall also include any explanation or other information provided by either Party to the Recipient concerning the foregoing and which has been identified by the Party providing the information as confidential at the time it is initially provided, whether printed or electronic. Confidential Information may also include any password or other information necessary to access electronic copies of Confidential Information.

Permitted Scope of Use

2. The Recipient may use the Confidential Information solely for the purposes of providing or receiving EECA, as the case may be, in accordance with the Legislation and the Supply Agreement and for no other reason or purpose.

No Obligation to Disclose

3. This Agreement does not obligate either Party to disclose any Confidential Information to the other.

Protection of Confidential Information

4. The Recipient shall hold the Confidential Information in strict confidence and shall strictly protect the Confidential Information from all harm, loss, theft, reproduction and unauthorized access, employing at least the same degree of care that the Recipient employs to protect its own confidential information of a similar nature, but in any event, not less than reasonable care. The Recipient shall ensure that such Confidential Information is not disclosed, published,

released, transferred or otherwise made available in any form to, for the use or benefit of, any person except as provided in this Agreement.

Acknowledgements

5. The Recipient acknowledges that the Confidential Information is confidential and a trade secret and is owned by the Disclosing Party and is highly valuable and material to the interests, business and affairs of the Disclosing Party and that any unauthorized disclosure thereof by the Recipient would be detrimental to the Disclosing Party.

Permitted Disclosures

6. The Recipient shall be permitted to disclose relevant aspects of the Confidential Information to its employees and professional advisors to the extent that such disclosure is reasonably necessary for the performance of its duties and obligations; provided, however, that prior to such disclosure the Recipient shall inform such persons and parties of the confidential nature of the Confidential Information and each such person or party signs the undertaking attached to this Confidentiality Agreement. The Recipient shall inform the Disclosing Party of the name of each person to whom it has disclosed the Confidential Information in accordance with this provision and shall provide to the Disclosing Party the signed undertaking. The Recipient shall be fully responsible for ensuring that any such persons to whom it discloses the Confidential Information complies with the confidentiality obligations contained in this Agreement and shall be liable for any breach of this Agreement by such persons.
7. The non-disclosure obligations in this Agreement shall not restrict any disclosure by the Recipient pursuant to any applicable law or an order of any court of competent jurisdiction or regulatory body with regulatory responsibilities over the Recipient, provided that the Recipient shall provide the Disclosing Party with prompt prior written notice of its obligation to disclose so that the Disclosing Party may seek a protective order or other appropriate remedy concerning the disclosure of its Confidential Information and/or waive compliance with the confidentiality provisions of this Agreement. In addition, the Recipient shall take reasonable steps, to the extent permitted by law, to remove from the Confidential Information that is required to be disclosed, any information that is commercially sensitive to the Disclosing Party. In the event of an order for disclosure by a court of competent jurisdiction or regulatory body with regulatory responsibilities over the Recipient, the Recipient shall first notify the Disclosing Party of such order and allow the Disclosing Party not less than ten (10) days to remove any such information that is commercially sensitive.

Term

8. The term of this Agreement shall commence on the effective date of the Supply Agreement unless superceded by another form of writing, and notwithstanding the return of any Confidential Information or any other event, shall continue in full

force and effect for a period of FIVE (5) years from the effective date of this Agreement.

Equitable Remedy

9. The Recipient acknowledges that any unauthorized use of the Confidential Information or any breach of its obligations under this Agreement will result in irreparable harm to the Disclosing Party which cannot be adequately compensated for by damages. Neither the Recipient, nor any term in this Agreement, shall interfere with, delay, or prevent the Disclosing Party from seeking an interim and interlocutory equitable remedy to enforce any provision of this Agreement. The Recipient agrees not to oppose an application for equitable relief by the Disclosing Party in such circumstances. Any such relief or remedy shall not be exclusive, but shall be in addition to all other available legal or equitable remedies. The Recipient agrees that the provisions of this Section are fair and reasonable in the commercial circumstances of this Agreement. This Article shall survive the termination of this Agreement.

Return of Information

10. On the earlier of either thirty (30) days following the termination of the Supply Agreement or at the written request of the Disclosing Party (and unless superceded by another form of writing), the Recipient shall return or destroy (at the Disclosing Party's direction) and delete from all electronic devices all Confidential Information provided to it, including all copies (and all notes and documents prepared by the Recipient that may incorporate same) and still in the Recipient's possession (and otherwise under its control or in the possession of other persons to whom it has been provided as permitted hereunder) and, if requested by the Disclosing Party, shall provide written confirmation to the Disclosing Party to that effect. Notwithstanding the forgoing, the Recipient shall be entitled to retain the Confidential Information in one legal file copy that may be retained solely for the determination of its legal obligations under this Agreement.

Residual Information

11. The Recipient or its designate or any other person having access to the Confidential Information pursuant to this Agreement shall not, during and after the termination of this Agreement, use in its business any Residual Information. "Residual Information" means the ideas, know-how and techniques that would be retained in the unaided memory of an ordinary person skilled in the art, not intent on appropriating the proprietary information of the disclosing party, as a result of such person's access to, use, review, evaluation, or testing of the Confidential Information of the disclosing party for the purposes described herein. An employee's memory is unaided if the employee has not intentionally memorized the Confidential Information for the purpose of retaining and subsequently using or disclosing it.

Limited Rights

12. The Recipient agrees that no rights are granted to Recipient other than the limited rights to use the Confidential Information on the terms of this Agreement. For certainty, no license is granted under this Agreement (directly or indirectly) under any patent, discovery, copyright, or other intellectual or industrial property right now or in the future.

Indemnity

13. The Recipient shall indemnify and hold the Disclosing Party harmless from any and all loss, liability, cost or expense (including, without limitation, solicitor's costs on a solicitor and client basis and all other costs of defence) caused in whole or in part by the Recipient's breach of any provision of this Agreement. This Article shall survive the termination of this Agreement.

Governing Law

14. This Agreement is governed and shall be construed in accordance with the laws of the Province of Nova Scotia.

General Provisions

15. This Agreement is binding on the Parties, their administrators, successors, executors and assigns.

Executed and delivered this day of 20__.

EfficiencyOne

Nova Scotia Power Incorporated

By: _____

By: _____

Name:

Name:

Title:

Title:

SCHEDULE "A" to CONFIDENTIALITY AGREEMENT

UNDERTAKING

I _____, HAVE READ AND
AGREE TO ABIDE AND AM BOUND BY THE TERMS AND CONDITIONS SET
OUT IN THE CONFIDENTIALITY AGREEMENT DATED THE ____ DAY OF
____ BETWEEN EFFICIENCYONE AND NOVA SCOTIA
POWER INCORPORATED.

Dated the ____ day of _____ 201__.

Witness

Name:

Recipient Designate

SCHEDULE E

EECA PLAN

[Subject to approval by the UARB]

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**Supply Agreement for
Electricity Efficiency and Conservation Activities**

Between

Nova Scotia Power Incorporated

and

EfficiencyOne

Effective Date – January 1, ~~2020~~2023

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- 7 | Schedule "D": Confidentiality Agreement
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THIS AGREEMENT made as of the _____ day of _____, ~~2019~~ 2022 and effective as of the 1st day of January, ~~2020~~ 2023 (the “**Effective Date**”).

BETWEEN:

NOVA SCOTIA POWER INCORPORATED,
a body corporate, organized under the laws
of the Province of Nova Scotia

(hereinafter called “**NSPI**”)

- and -

EFFICIENCYONE,
a body corporate, organized under the laws of
Canada

(hereinafter called “**EfficiencyOne**”)

WHEREAS:

- A. EfficiencyOne and NSPI are both public utilities pursuant to the Act; and
- B. Pursuant to the Act, EfficiencyOne has the exclusive right to supply NSPI with reasonably available, cost-effective Electricity Efficiency and Conservation Activities as the Franchise Holder; and
- C. Pursuant to the Act, NSPI is obligated to undertake cost-effective Electricity Efficiency and Conservation Activities that are reasonably available in an effort to reduce costs for its customers; and
- D. Pursuant to the Act, NSPI shall meet its obligations by entering into an agreement with the Franchise Holder for the supply of cost-effective Electricity Efficiency and Conservation Activities.

NOW THEREFORE witnesses that in consideration of the premises and the mutual covenants and obligations herein and other good and valuable consideration, the sufficiency and receipt of which are hereby acknowledged, the parties agree as follows:

1. INTERPRETATION

1.1 The following terms shall be interpreted as follows in this Agreement:

- (a) “**Act**” shall mean the *Public Utilities Act*, R.S.N.S. 1989, c.380, as amended from time to time.
- (b) “**Agreement**” means this agreement between NSPI and EfficiencyOne including all Schedules attached hereto.
- (c) “**Business Day**” means Monday to Friday, except federal, provincial, and civic holidays within the Province of Nova Scotia.

- (d) **"Consequential Losses"** means consequential, special, incidental, multiple, exemplary or punitive damages including lost profits, whether such claim of lost profits is categorized as indirect, direct or consequential damages or under any alternative theory of recovery.
- (e) **"Contract Documents"** means without limitation, the following documents, including any amendments thereto agreed in writing by the parties:
- (i) this Agreement; and
 - (ii) all Schedules to the Agreement.
- (f) **"Contract Price"** has the meaning ascribed to it in Section 4.1.
- (g) **"EECA Plan"** means the plan prepared by EfficiencyOne and approved by the UARB and attached hereto as Schedule "E".
- (h) **"Electricity Efficiency and Conservation Activities"** or **"EECA"** means the electricity efficiency and conservation activities as identified in Schedule "A" attached hereto.
- (i) **"Event of Default"** has the meaning ascribed to it in Section 20.4.
- (j) **"Environmental Laws"** means all applicable federal, provincial, regional, municipal or local laws with respect to environmental matters contained in the statutes, regulations, rules, standards, requirements, ordinances, policies, guidelines, orders, approvals, notices, permits or directives having the force of law, in effect as at the date hereof and as may be brought into effect at future date.
- (k) **"Force Majeure Event"** means any event or circumstance not reasonably within the control of the Party affected which wholly or partly prevents the performance by that Party of its obligations under this Agreement, provided that such Party is in good faith unable to perform such obligations by any commercially reasonable substitute. A Force Majeure Event includes acts of God, war, riot, fire, explosion, flood, hurricane, epidemics, acts of governmental authorities, acts of terrorism. Notwithstanding anything else contained herein, a Force Majeure Event excludes (a) any event or circumstance causing direct or indirect delay in, or failure to perform any of a Party's obligations under this Agreement, attributable to a lack of reasonable diligence on the part of a Party or on the part of any vendor or subcontractor of a Party, including any event or circumstance which a Party or any vendor or subcontractor, acting diligently, could reasonably have been expected to foresee, avoid or overcome in the performance of its obligations; and (b) any event or circumstance caused by the breach of a Party's obligations or the fault or negligence of a Party or the fault or negligence of any vendor or subcontractor, or by violation of applicable laws or regulations by a Party or any of a Party's vendors or subcontractors. For certainty, adverse weather of any kind other than events specified above shall not be considered a Force Majeure Event.
- (l) **"Franchise"** has the meaning ascribed to it in the Act.
- (m) **"Franchise Holder"** has the meaning ascribed to it in the Act.

- (n) **"Governmental Authority"** means any federal, provincial, regional, municipal or local government or authority or other political subdivision thereof and entity or person exercising executive, legislative, judicial, regulatory or administrative functions of, or pertaining to, government.
- (o) **"Hazardous Substances"** means any substance or material that is prohibited, controlled or regulated by any Governmental Authority pursuant to Environmental Laws, including any contaminants, pollutants, petroleum or other hydrocarbons and their derivatives and by-products, dangerous substances or goods, including asbestos, liquid wastes, special wastes, toxic substances, hazardous or toxic chemicals, hazardous wastes, hazardous materials or hazardous substances as defined in or pursuant to any Environmental Law, or any substance or material not inherently hazardous but which would, in sufficient quantities, be hazardous.
- (p) **"Indemnified Costs"** means all liabilities, claims, actions, causes of action, judgments, orders, damages, costs (including those incurred in connection with any investigation of site conditions or any clean-up, environmental remediation, removal or restoration work), expenses (including all reasonable consultant, expert and legal fees and expenses), fines, penalties, losses, or any resulting damages, harm or injuries to the person or property of any third parties or to any natural resources and for which the indemnified party is liable and has incurred losses. Without limiting the foregoing, Indemnified Costs shall include:
- (i) the costs of defending and/or counterclaiming or claiming over and against third parties in such manner as the indemnified party in its sole discretion may determine;
 - (ii) the costs relating to any governmental investigation, proceeding or claim; and
 - (iii) any costs, liabilities or damages arising out of a settlement of a claim by the indemnified party, with or without the consent of the indemnifying party.
- (q) **"Law"** means the common law, the law of equity and all federal or provincial statutes or municipal by-laws and all regulations, orders, directives, permits and licenses thereunder, which apply to or otherwise affect NSPI or EfficiencyOne with respect to the supply of the EECA, or the property of NSPI or EfficiencyOne, real or personal, or any part thereof, including the Act and all environmental, occupational, health and safety laws.
- (r) **"Liens Indemnities"** has the meaning ascribed to it in Section 18.1.
- (s) **"Liens and Claims"** has the meaning ascribed to it in Section 18.1.
- (t) **"Minister"** has the meaning ascribed to it in the Act.
- (u) **"Party"** means either EfficiencyOne or NSPI. **"Parties"** means EfficiencyOne and NSPI.
- (v) **"Personal Information"** shall mean the information provided by NSPI to EfficiencyOne pursuant to Section 79K of the Act.

- (w) **"Release"** or **"Released"** means a releasing, adding, spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, migrating, dispersing, dispensing, disposing or dumping.
- (x) **"Significant Changes"** means any proposed change to the EECA Plan for which the UARB orders or directs EfficiencyOne to obtain the approval of the UARB prior to the implementation of such proposed change.
- (y) **"Subcontractor"** means any contractor, supplier or consultant hired by EfficiencyOne in accordance with this Agreement to perform any portion of the EECA.
- (z) **"Term"** has the meaning ascribed to it in Section 2.1.
- (aa) **"UARB"** means the Nova Scotia Utility and Review Board.
- (bb) **"CASL"** means An Act to promote the efficiency and adaptability of the Canadian economy by regulating certain activities that discourage reliance on electronic means of carrying out commercial activities, and to amend the Canadian Radio-television and Telecommunications Commission Act, the Competition Act, the Personal Information Protection and Electronic Documents Act and the Telecommunications Act, S.C. 2010, c. 23, as amended from time to time.
- 1.2 Unless otherwise specified in this Agreement or unless the context otherwise requires:
- (a) words of any gender include each other gender;
- (b) using the singular or plural number also include the plural or singular number, respectively;
- (c) the insertion of headings in this Agreement is for convenience only and shall not be construed so as to affect the interpretation or construction of this Agreement;
- (d) the terms "hereof," "herein," "hereto," "hereunder" and words of similar or like import refer to this entire Agreement and not to any particular Section, Schedule or other subdivision of this Agreement;
- (e) references to a particular "Section" or "Schedule" are, unless otherwise noted, references to that Section of, or Schedule to this Agreement;
- (f) the words "include," "includes" and "including" shall be deemed to be followed by "without limitation" or "but not limited to";
- (g) references to any applicable law, legislation or regulation shall be construed as a reference to such law, legislation or regulation as each may be in effect from time to time;
- (h) references to any agreement or document (including this Agreement) shall (i) include all Schedules, appendices, and other attachments thereto, and (ii) be construed at the particular time as a reference to such agreement or document as amended, modified or supplemented and in effect from time to time and shall include a reference to any document which amends, modifies or supplements it, or is entered into, made or given pursuant to or in accordance with its terms;

- (i) references to (i) days shall refer to calendar days unless Business Day is specified, (ii) weeks and months shall refer to calendar weeks and months, respectively, and (iii) years shall refer to calendar years;
- (j) in computing any period of time prescribed or allowed under this Agreement, the day of the act, event or default from which the designated period of time begins to run shall be included. If the last day of the period so computed is not a Business Day, then the period shall run until the close of business on the next Business Day;
- (k) the Contract Documents are complementary, and what is required by any one shall be as binding as if required by all;
- (l) words and abbreviations which have well known technical or trade meanings are used in the Contract Documents in accordance with such recognized meanings; and
- (m) as both Parties were actively involved in preparing the terms and conditions of this Agreement and as they both had access to and relied upon counsel in this process, there shall be no presumption that any one or the other Party prepared this Agreement and no provision of this Agreement shall be construed against either Party based upon the process of preparation of proposals and drafts of the Agreement.

1.3 If there is a conflict within the Agreement, the order of precedence of documents, from highest to lowest, shall be:

- (a) Sections 1 to 27;
- (b) Schedule "A" – Electricity Efficiency and Conservation Activities; and
- (c) all other Schedules.

2. TERM & RESERVATION OF RIGHTS

- 2.1 The term of this Agreement shall be three (3) years from the Effective Date and shall automatically terminate on December 31, ~~2022-2025~~ unless terminated earlier in accordance with the terms of this Agreement and the Act (the "Term").
- 2.2 During the Term, NSPI shall purchase from EfficiencyOne and EfficiencyOne shall supply to NSPI, the EECA in accordance with the terms and conditions of this Agreement and the Act.
- 2.3 Notwithstanding anything contained herein, and subject to any requirement for review or approval by the UARB, nothing contained in this Agreement shall in any way effect the rights of NSPI pursuant to Section 79I(3) of the Act.

3. ELECTRICITY EFFICIENCY and CONSERVATION ACTIVITIES

- 3.1 For the Term of this Agreement, EfficiencyOne will,
- (a) provide the EECA in accordance with this Agreement;

- (b) provide sufficient resources to enable EfficiencyOne to perform its obligations on time and in accordance with this Agreement;
- (c) carry out the EECA in a professional, expeditious and economical manner, in accordance with the Act;
- (d) manage the EECA in an efficient manner; and
- (e) perform and supply the EECA in a safe and environmentally sound manner and in compliance with applicable Law.

3.2 The Parties acknowledge and agree that EfficiencyOne shall be solely responsible for the delivery of the EECA Plan. For greater certainty and notwithstanding the attachment of the EECA Plan as Schedule "E" – Approved EECA Plan, NSPI shall have no liability with respect to the EECA Plan saving and excepting any liability which may arise as a result of NSPI's failure to comply with the Act.

4. PRICE & PAYMENT

4.1 NSPI agrees to pay EfficiencyOne for EECA as set out in Schedule "B" – Compensation (the "**Contract Price**").

4.2 The Contract Price shall constitute full compensation for the EECA, and no additional compensation shall be payable to EfficiencyOne arising out or resulting from any productivity losses, overhead or indirect costs or other costs and expenses of any kind whatsoever.

4.3 NSPI shall make monthly payments on the first Business Day of each month in accordance with Schedule "B" to EfficiencyOne on account of the Contract Price when due, together with applicable HST. EfficiencyOne will submit an invoice to NSPI in advance of the payment date referenced in Schedule "B".

4.4 Unless otherwise indicated all dollar amounts referred to in this Agreement are in lawful money of Canada.

4.5 If applicable, payments shall be subject to harmonized sales tax (as defined in the *Excise Tax Act* (Canada)) ("**HST**"). No additional taxes (foreign or domestic), customs, duties or brokerage fees shall apply.

4.6 If applicable, NSPI will withhold from payments to EfficiencyOne any amounts required to be withheld under applicable Laws and treaties in respect of services rendered in Canada by a non-resident and may remit them to the relevant authority. Where available, statutory withholding may be waived if EfficiencyOne delivers to NSPI a formal waiver of the withholding requirement issued and signed by Canada Revenue Agency. The Parties shall cooperate at all times to ensure that all proper withholdings are deducted from payments and if any withholdings are overlooked then such withholdings may be deducted from later payments.

5. NOTIFICATION OF SIGNIFICANT CHANGES

5.1 EfficiencyOne shall provide notice of Significant Changes to NSPI at the same time as EfficiencyOne makes application to the UARB for the approval of the Significant Changes. Subject to the terms of the Act and the general discretion of the UARB under

the Act, NSPI shall, have the right to make written submissions to the UARB on any such Significant Changes to the EECA Plan.

6. SAFETY

6.1 EfficiencyOne shall at all times be responsible for safety and loss management in the supply or performance of the EECA.

6.2 EfficiencyOne shall ensure that all employees, Subcontractors, agents and representatives of EfficiencyOne comply with all federal, provincial and municipal health, safety and environmental statutes, regulations, policies and guidelines and all health, safety and environmental rules as prescribed by EfficiencyOne.

7. PROTECTION OF PROPERTY

7.1 EfficiencyOne shall take all commercially reasonable steps to protect the property of NSPI's customers and other third parties from damage which may occur as the result of the performance of the EECA.

7.2 Should EfficiencyOne damage the property of NSPI's customers or property of other third parties while performing the EECA, EfficiencyOne shall make good such damage at EfficiencyOne's expense and shall indemnify NSPI from and against all liabilities, claims, damages, settlements, awards, costs, expenses and proceedings incurred by NSPI or its servants, employees and/or agents in respect of such damage, except to the extent such damage occurs as a result of the negligent acts of NSPI or those for which NSPI is responsible at Law.

8. ENVIRONMENT

8.1 EfficiencyOne and its Subcontractors shall at all times comply with all Environmental Laws that apply in any way to the supply or performance of the EECA. EfficiencyOne and its Subcontractors shall not cause, permit or suffer the Release of a Hazardous Substance in contravention of any Environmental Laws.

8.2 Notwithstanding any other provision in this Agreement (and in addition to any other right to indemnity held by NSPI under the terms of the Agreement) EfficiencyOne shall indemnify NSPI, NSPI's parent, their respective subsidiaries, affiliates and related companies, and their respective officers, directors, employees, agents and shareholders, and agrees to hold each of them harmless from and against any and all Indemnified Costs resulting from any Release of any Hazardous Substance which is caused or contributed to by EfficiencyOne or its Subcontractors or any breach of any Environmental Law by EfficiencyOne or its Subcontractors.

9. EFFICIENCYONE'S COVENANTS

9.1 EfficiencyOne warrants, covenants and agrees with NSPI that:

(a) it has all requisite capacity and authority to execute, deliver and perform its obligations under this Agreement;

(b) this Agreement has been duly and validly executed and delivered by EfficiencyOne and constitutes a legal, valid and binding obligation of EfficiencyOne enforceable against EfficiencyOne in accordance with its terms;

- (c) to its knowledge, there is no matter, thing or event, including without limitation, any litigation, proceeding, breach, default or financial circumstance that would adversely affect EfficiencyOne's ability to perform its obligations under this Agreement;
- (d) it will furnish all labour, materials, products, tools, and other necessary components necessary to perform and provide the EECA, unless otherwise provided herein;
- (e) it shall diligently perform or cause to be performed the EECA in a proper and workmanlike manner;
- (f) it has the skills, expertise and resources to carry out the EECA and to comply, observe and perform the obligations to which it is subject in accordance with the terms of this Agreement;
- (g) prior to commencing any work hereunder, it shall obtain and maintain all permits, licenses and notices that a prudent supplier acting in accordance with industry standards would be required to obtain, maintain and provide in comparable circumstances and shall comply with all applicable Laws, ordinances, rules, regulations, codes and orders of any and all authorities having jurisdiction which are or become in force during the Term in respect of the EECA;
- (h) it will comply with applicable federal, provincial and municipal statutes, regulations and bylaws pertaining to the EECA performed by or on behalf of EfficiencyOne under this Agreement. EfficiencyOne shall be responsible for ensuring similar compliance by any suppliers and Subcontractors;
- (i) it is the Franchise Holder pursuant to the Act;
- (j) it is not a non-resident of Canada for the purposes of the *Income Tax Act*;
- (k) it will execute or cause to be made, done and executed all further acts, deeds, assurances, agreements, instruments or other documents as may be reasonably required to ensure fulfillment of the terms of this Agreement;
- (l) the EECA shall be delivered and performed by individuals duly licensed and authorized by Law, if applicable, to perform said undertakings;
- (m) the EECA shall be delivered and performed solely by EfficiencyOne or its Subcontractors and EfficiencyOne acknowledges that EfficiencyOne shall at all times remain responsible for the proper completion of this Agreement; and
- (n) upon becoming aware of a potential disruption having a material impact in the supply of the EECA, EfficiencyOne shall provide notification to the UARB and NSPI.

10. SUBCONTRACTORS

- 10.1 EfficiencyOne shall be permitted to subcontract the performance of any part of the EECA without the prior written approval of NSPI.

10.2 Where EfficiencyOne subcontracts any part of the EECA, EfficiencyOne shall preserve and protect the rights of the Parties under this Agreement with respect to the EECA to be supplied or performed under subcontract, and shall be as fully responsible to NSPI for the acts and omissions of Subcontractors and of persons directly or indirectly employed by them, as if they were acts and omissions of persons directly employed by EfficiencyOne.

10.3 Nothing contained in the Contract Documents shall create a contractual relationship between a Subcontractor and NSPI.

11. CONFIDENTIAL AND PERSONAL INFORMATION

11.1 The Parties have executed or agree to execute the confidentiality agreement attached hereto as Schedule "D" - Confidentiality ("**Confidentiality Agreement**").

11.2 EfficiencyOne shall be responsible for all physical and electronic security required to ensure the security of the Personal Information which has been provided by NSPI to EfficiencyOne.

11.3 EfficiencyOne shall indemnify and hold harmless NSPI for any liabilities, claims, damages, settlements, awards, costs, expenses and proceedings incurred by NSPI or its servants, employees and/or agents in consequence of EfficiencyOne's misuse of the Personal Information or any disclosure, whether intentional, inadvertent, negligent or otherwise of any of the Personal Information by EfficiencyOne contrary to the terms of this Agreement or the Act, or in consequence of EfficiencyOne's contravention of CASL.

12. PERFORMANCE REQUIREMENTS AND EVALUATIONS

12.1 EfficiencyOne's performance under the terms of this Agreement shall be measured in accordance with the performance requirements established by the UARB pursuant to Section 79M of the Act as set out in Schedule "C" – Performance Requirements.

13. FORCE MAJEURE

13.1 Neither Party shall be in breach of its obligations under this Agreement where failure to perform or delay in performance of any obligation is due, wholly or in part, to a Force Majeure Event.

13.2 Each Party shall notify the other Party promptly of any Force Majeure Event and shall take reasonable steps to minimize the impact of the failure or the delay and to resolve the event or occurrence that has given rise to the Force Majeure Event in order to resume performance. The time for performing an obligation as a result of Force Majeure Event shall be extended for the period lost, subject to the condition that the Term of this Agreement shall not be extended as a result of any Force Majeure Event.

13.3 Each Party suffering a Force Majeure Event shall take, or cause to be taken, such action as may be necessary to void, or nullify, or otherwise to mitigate, in all material respects, the effects of such Force Majeure Event. The Parties shall take all reasonable steps to ensure normal performance under this Agreement, including the resumption of any disrupted obligations.

13.4 For certainty, in no case shall the failure or omission of EfficiencyOne to carry out or observe any of the terms, provisions, or conditions of this Agreement or any negligent

act or omission of EfficiencyOne, or others for whom EfficiencyOne is responsible constitute an event of Force Majeure or result in an extension of the time to perform the EECA.

14. INDEMNITY

14.1 EfficiencyOne shall assume all risk of loss, damage or injury, including death, to person or property, caused by its directors, officers, employees, Subcontractors, agents or representatives, and agrees not to make or bring any claim, action or demand against NSPI or its directors, officers, servants, agents, or employees in respect of such loss, damage or injury excepting such loss, damage or injury caused by the negligence or wilful misconduct of NSPI or NSPI's directors, officers, servants, agents or employees.

14.2 EfficiencyOne agrees to indemnify and save harmless NSPI, its directors, officers, servants, agents, or employees, and their heirs, executors, administrators, successors and assigns, or any of them, from and against any liabilities, losses, expenses (including legal costs on a solicitor-client basis), claims, demands, actions, and causes of action, whatsoever suffered by NSPI by reason of, or in any way arising out of or in connection with a breach of this Agreement by EfficiencyOne excepting only to the extent caused by the negligence or wilful misconduct of NSPI or NSPI's directors, officers, servants, agents or employees.

14.3 NSPI agrees to indemnify and save harmless EfficiencyOne, its directors, officers, servants, agents, or employees, and their heirs, executors, administrators, successors and assigns, or any of them, from and against any liabilities, losses, expenses (including legal costs on a solicitor-client basis), claims, demands, actions, and causes of action, whatsoever suffered by EfficiencyOne by reason of, or in any way arising out of or in connection with a breach of this Agreement by NSPI excepting only to the extent caused by the negligence or wilful misconduct of EfficiencyOne or EfficiencyOne's directors, officers, servants, agents or employees.

14.4 The provisions set forth in this Section shall apply and be effective with respect to any claim, cause of action, or legal theory whatsoever including without limitation, claims based upon breach of contract, failure to meet performance guarantees, tort (including negligence) and strict liability.

14.5 EfficiencyOne shall defend, indemnify and hold harmless NSPI from any claim, suit, cause of action, judgment, cost or expense (including legal fees) based on a claim by a third party that any intellectual property which is part of the EECA or supply or performance of EfficiencyOne's obligations under this Agreement infringes any patent, copyright, trade secret or other intellectual property right, provided the EfficiencyOne is promptly notified of such claim and is given complete authority for defense of same. EfficiencyOne shall pay all damages, costs and expenses resulting from such a claim, including legal fees and settlement costs, but shall not be responsible for any cost, expense or compromise incurred by NSPI without EfficiencyOne's prior consent.

15. LIMIT OF LIABILITY

15.1 Neither Party shall be liable to the other Party for any Consequential Losses with respect to the performance or non-performance under this Agreement or for any actions undertaken in connection with or related to this Agreement.

15.2 EfficiencyOne's total liability to NSPI with respect to the performance or non-performance under this Agreement or for any actions undertaken in connection with or related to this Agreement shall be limited to the greater of the sum of two million dollars (\$2,000,000) or the proceeds of the applicable insurance policies taken out by EfficiencyOne under this Agreement ("**EfficiencyOne Limit of Liability**") provided that the EfficiencyOne Limit of Liability shall not apply to:

- (a) indemnification of NSPI by EfficiencyOne under the terms of this Agreement for any third party claims (including but not limited to EfficiencyOne's obligations pursuant to Sections 7.2, 8.2, 11.3, 14.5 and 18.1);
- (b) any wilful misconduct or fraud of EfficiencyOne or its employees, agents or representatives; and
- (c) any obligation on the part of EfficiencyOne to refund in whole or in part the Contract Price pursuant to this Agreement or the Act.

15.3 NSPI's total liability to EfficiencyOne with respect to the performance or non-performance under this Agreement or for any actions undertaken in connection with or related to this Agreement shall be limited to the sum of two million dollars (\$2,000,000) ("**NSPI Limit of Liability**") provided that the NSPI Limit of Liability shall not apply to:

- (a) any wilful misconduct or fraud of NSPI or its employees, agents or representatives; and
- (b) NSPI's liability for payment of the Contract Price pursuant to the Agreement or the Act.

16. INSURANCE

16.1 EfficiencyOne shall obtain, maintain and pay for, during the entire Term of this Agreement, the following minimum insurance coverage as follows, such insurance as it relates to this Agreement shall be in a form and from an insurer acceptable to NSPI:

- (a) General liability insurance shall be in the name of EfficiencyOne and shall name NSPI as an additional insured and shall have limits of not less than five million dollars (\$5,000,000) inclusive per occurrence for bodily injury, death, and damage to property including loss of use thereof. Such insurance shall be primary and non-contributing with, and not in excess of, any other insurance available to NSPI. This policy shall also contain cross liability and severability of interest and blanket contractual liability.
- (b) Environmental impairment insurance with limits of not less than five million dollars (\$5,000,000);
- (c) Automobile liability insurance in respect of licensed vehicles shall have limits of not less than two million dollars (\$2,000,000) inclusive per occurrence for bodily injury, death, and damage to property. For automobiles not owned or operated by or on behalf of EfficiencyOne the insurance shall be in the form of a standard non-owned automobile policy and shall include standard contractual liability endorsement. For automobiles owned or operated by or on behalf of EfficiencyOne the insurance shall be in the form of a standard owner's form automobile policy and shall provide third party liability and accident benefits

insurance covering licensed vehicles owned or operated by or on behalf of EfficiencyOne.

(d) Property Insurance covering all loss of or damage to EfficiencyOne's property and equipment of EfficiencyOne or for which EfficiencyOne is legally liable or responsible used in performance of the EECA for the full replacement value, which insurance shall not allow subrogation claims by the insurer against NSPI.

(e) To the extent that the EECA includes the provision of professional services, professional liability errors and omissions insurance covering all claims arising out of errors and omissions of EfficiencyOne in the performance of professional services as part of the EECA with a limit of two million dollars (\$2,000,000). In the event other claims erode EfficiencyOne's professional errors and omissions insurance below two million dollars (\$2,000,000), in the annual aggregate, EfficiencyOne agrees to reinstate the limit.

(f) Workers' compensation to the full extent required in Nova Scotia and wherever EfficiencyOne's personnel contracts of employment are made or are expressed to be made.

16.2 If EfficiencyOne fails to effect or keep in force any of the foregoing insurances, NSPI may, without prejudice to any other right or remedy, effect such insurance and pay the premiums due and recover the same as a deduction from any other monies due to EfficiencyOne under this Agreement.

16.3 EfficiencyOne shall be responsible to pay deductible amounts and for determining the deductible amount in respect of each policy. EfficiencyOne shall not violate, nor knowingly permit to be violated, any conditions of the policies maintained according to the provisions of this Section, and it shall be EfficiencyOne's duty and responsibility to impose upon each Subcontractor the same responsibilities and obligations imposed upon EfficiencyOne under such provisions.

16.4 EfficiencyOne agrees to provide proof of insurance to NSPI on an annual basis. Such proof shall be in the form of a certificate of insurance signed by EfficiencyOne's insurance broker.

17. INTELLECTUAL PROPERTY

17.1 NSPI acknowledges that all branding, trade and business marks of EfficiencyOne used in the course of provision of EECA pursuant to this Agreement, (the "**EfficiencyOne Brands**") are, and shall remain, the sole and exclusive property of EfficiencyOne and shall not be used by NSPI without EfficiencyOne's express consent. Upon termination of this Agreement, NSPI shall immediately upon instruction from EfficiencyOne return or destroy, as instructed by EfficiencyOne, the EfficiencyOne Brands.

17.2 Any trademarks, brands, logos or other branding or trade or business marks used in NSPI's business ("**NSPI Brands**") shall remain the sole and exclusive property of NSPI and shall not be used by EfficiencyOne for any purpose except in connection and as necessary for the provision of the EECA. Upon termination of this Agreement, EfficiencyOne shall immediately upon instruction from NSPI return or destroy, as instructed by NSPI, the NSPI Brands.

18. LIENS AND CLAIMS

18.1 EfficiencyOne shall indemnify and hold harmless NSPI, NSPI's parent and their subsidiaries and affiliates (collectively the "**Lien Indemnitees**" or singularly "**Lien Indemnatee**") and defend each of them from and against any and all losses and costs arising out of any and all claims for payment, liens, attachment or any other process, filed against any property of the Lien Indemnitees by or in respect of a Subcontractor of any tier or any other party providing work, materials in respect of the EECA or any part thereof (referred to in this Section as "**Liens or Claims**"), including solicitor and client fees and expenses incurred by NSPI in discharging any such Liens or Claims or similar encumbrances.

18.2 EfficiencyOne shall discharge promptly any Liens or Claims. If EfficiencyOne does not promptly satisfactorily discharge such Liens or Claims, NSPI at its sole option may (i) require EfficiencyOne to pay, within five (5) Business Days after request by NSPI, or (ii) subject to any requirements of the *Builders' Lien Act* of Nova Scotia, offset against any holdback or other amounts due or to become due to EfficiencyOne, all costs and expenses incurred by NSPI or other Lien Indemnatee in causing the release of, paying or settling such Liens or Claims. EfficiencyOne shall have the right to contest any such Liens or Claims, provided it first provides to NSPI a bond or other assurance of payment reasonably satisfactory to NSPI in the amount of such Liens or Claims and in form and substance reasonably satisfactory to NSPI. In no circumstance whatsoever shall NSPI be liable for a greater amount than the amount payable by NSPI to EfficiencyOne.

19. DISPUTE RESOLUTION

19.1 In the event of a dispute in connection with this Agreement, a senior representative of EfficiencyOne and a senior representative of NSPI shall promptly meet to discuss and resolve the dispute and the Parties shall have thirty (30) days to resolve the dispute (or ten (10) days if either Party notifies the other Party that the matter requires urgent resolution).

19.2 Unless the parties agree otherwise, in the event resolution cannot be achieved in accordance with Section 19.1 of this Agreement, then such dispute or difference shall be referred to the UARB in accordance with Section 79P of the Act.

19.3 Notwithstanding any dispute, EfficiencyOne shall diligently carry out the EECA, and shall not suspend, impair, interfere with, restrict or discourage the prompt completion of any portion of the EECA, unless specifically authorized to do so by the UARB. .

20. DEFAULT AND TERMINATION

20.1 This Agreement may be terminated immediately by either Party, in whole or in part, upon the happening of one or more of the following events:

- (a) EfficiencyOne's Franchise is terminated and the Agreement has not been assigned by the Minister; or
- (b) The UARB approves the termination of the Agreement.

In the event of a termination pursuant to this Section 20.1, neither Party shall be entitled to any compensation or damages for any Consequential Losses as a result of such termination. Immediately upon receipt of such termination notice, EfficiencyOne will

discontinue all EECA under this Agreement and will only finish such portions of the EECA as may be necessary to preserve and protect the EECA already in progress. Such termination does not relieve either Party from any of their respective obligations under this Agreement for EECA provided up to the date of termination. Any claim for payment by EfficiencyOne must be asserted within thirty (30) days from the date of such termination.

20.2 Notwithstanding any other provision in this Agreement, in the event this Agreement is terminated in accordance with Section 20.1(a), EfficiencyOne shall:

(a) Immediately return all monies paid on account of the Contract Price which amounts have not been legitimately incurred or subject to contractual commitments for expenditure which cannot otherwise be mitigated to NSPI; and

(b) Provide to NSPI all reasonable required termination assistance to allow the EECA provided under this Agreement to continue and to facilitate the orderly transition of the EECA to NSPI or any third party as directed by NSPI, provided that EfficiencyOne shall be entitled to commercially reasonable payment for such transition services on a time and material basis.

20.3 The Parties acknowledge that this Agreement is subject to the general supervision of the UARB.

20.4 A Party shall be determined to be in default of its obligations under this Agreement if (each a "**Event of Default**"):

(a) it is in breach of any material term or condition of this Agreement, which breach is not cured by the Party within thirty (30) days after written notice from the other Party;

(b) it assigns this Agreement other than as permitted by the Act and/or the UARB;

(c) any representation or warranty made by either Party shall prove to be untrue when made in any material respect;

(d) there is a sale, transfer or relinquishment, voluntary or involuntary, by operation of law or otherwise, of legal control of the business of either Party except for a transfer to a related corporation or a transfer resulting from a merger, acquisition, amalgamation or reorganization, or, in the case of EfficiencyOne, a change in the Membership of the corporation;

(e) Either Party sells, transfers or assigns all or substantially all of its assets;

(f) a petition in bankruptcy is filed with respect to either Party; or

(g) any proceeding is commenced under any bankruptcy or insolvency legislation or under any other federal, state or provincial law relating to insolvency or bankruptcy, the adjudication of either Party as a bankrupt, the appointment by any competent court having jurisdiction of a temporary or permanent receiver, trustee or other officer having similar powers over either Party its business or assets, or the making of any assignment by either Party for the benefit of its creditors.

- 20.5 If a breach notified pursuant to Sections 20.4(a) cannot be corrected within the period required therein, the defaulting Party shall not be in breach or violation if it:
- (a) commences and diligently and continuously carries out the correction of the breach or violation within the specified time;
 - (b) provides to the non-defaulting Party, and the UARB an acceptable plan for such correction; and
 - (c) corrects the breach or violation in accordance with such plan.
- 20.6 Upon the occurrence of an Event of Default, the non-defaulting Party may apply to the UARB to terminate this Agreement in whole or in part.

21. NOTIFICATIONS

- 21.1 All notices to be given to either Party under this Agreement shall be written and addressed to the NSPI and to EfficiencyOne as follows:

To NSPI:

Nova Scotia Power Incorporated
1223 Lower Water Street
PO Box 910
Halifax, NS B3J 3S8
Attention: Corporate Secretary
Facsimile: (902) 428-6171

To EfficiencyOne:

EfficiencyOne
230 Brownlow Avenue
Suite 300
Dartmouth, NS B3B 0G5
Attention: CEO
Facsimile: (902) 470-3599

- 21.2 All notices may be sent by facsimile, a nationally recognized overnight courier service, first class mail or hand delivered. Notice shall be given when received by the addressee on a Business Day. In the absence of proof of the actual receipt date, the following presumptions will apply:
- (a) Notices sent by facsimile shall be presumed to have been received upon the sending Party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is not a Business Day or is after five p.m. (local time for the recipient) on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day.

(b) Notice by overnight courier shall be presumed to have been received on the next Business Day after it was sent.

(c) Notice by first class mail shall be presumed delivered five (5) Business Days after mailing.

21.3 Either Party may modify its address for notices by advance written notice to the other Party.

22. AUDIT AND INSPECTION

22.1 EfficiencyOne shall, during the Term and for a period of thirty-six (36) months thereafter, keep accurate records of all EECA supplied to NSPI, as necessary to determine that the EECA was provided in accordance with the terms and conditions of this Agreement.

22.2 NSPI shall have the right to apply to the UARB to request access to any of the records referred to in 22.1.

22.3 NSPI shall have the right to apply to the UARB to inspect or observe the EECA at all times, whether using its own forces or those of a designated third party. EfficiencyOne shall facilitate such inspections and provide sufficient, safe and proper facilities at all times for inspection of the EECA.

23. ASSIGNMENT

23.1 Neither Party shall assign all or any portion of this Agreement without the prior written approval of the UARB and/or the Minister as the situation requires.

24. SHARING OF DATA AND INFORMATION

24.1 EfficiencyOne shall work co-operatively with NSPI to provide NSPI with information and data from time to time in order to assist NSPI with planning and load forecasting as may be reasonably required by NSPI. For greater certainty, such information and data shall be consistent with the past practices of the Parties.

24.2 In the event of a dispute regarding any request for information by NSPI, NSPI shall have the right to apply to the UARB to request access to the information and data referred to in 24.1.

25. COORDINATION MEETINGS AND REPORTS

25.1 During the Term of this Agreement, EfficiencyOne shall prepare and deliver to the UARB and NSPI a quarterly report (the "Quarterly Report") in a form acceptable to the UARB.

25.2 EfficiencyOne shall prepare and deliver to the UARB and NSPI an annual report (the "Report") in a form acceptable to the UARB. For greater certainty, the Report shall summarize and provide details as to the EECA and milestones achieved in the prior year, contain a discussion and analysis of major discrepancies relative to the EECA Plan's intent and forecasts, EfficiencyOne's financial statement for the previous year with respect to the EECA, evaluation reports and a summary of planned versus actual savings and costs for each metric.

25.3 The Parties agree that ongoing coordination and regular communication between NSPI and EfficiencyOne is important in order to ensure effective planning. To that end, the Parties shall meet quarterly or as otherwise agreed upon to discuss the provision of the EECA.

26. GENERAL

26.1 This Agreement shall only be renewed in accordance with the provisions of the Act.

26.2 This Agreement shall extend to, be binding upon and enure to the benefit of the respective successors and permitted assigns of the Parties hereto.

26.3 EfficiencyOne will be an independent contractor. EfficiencyOne shall not act as an agent for NSPI, bind NSPI to any obligation with a third party, nor hold itself out as having authority to bind or obligate NSPI. None of the persons engaged by EfficiencyOne or any of its Subcontractors in the performance of the EECA will be considered employees of NSPI.

26.4 This Agreement shall be deemed to have been made in and shall be governed by, construed and interpreted in accordance with the laws of the Province of Nova Scotia and the laws of Canada, as applicable therein. Where the provisions of this Agreement or the Act permit or require a matter to be referred to or proceeded with before a court, or in any other case where the Parties bring a matter in respect of this Agreement before a court, the Parties irrevocably attorn to the jurisdiction of the Supreme Court of Nova Scotia.

26.5 No consent or waiver, express or implied, by any Party to this Agreement of any breach or default by any other Party in the performance of its obligations under this Agreement or of any of the terms, covenants or conditions of this Agreement shall be deemed or construed to be a consent or waiver of any subsequent or continuing breach or default in such Party's performance.

26.6 Time shall be of the essence for purposes of this Agreement.

26.7 This Agreement, upon approval by the UARB, shall represent the entire Agreement between the Parties with respect to the subject matter hereto and shall not be modified, varied or amended except by an instrument in writing signed by the Parties and approved by the UARB or as ordered or directed, by the UARB at anytime.

26.8 Should any provision of the Agreement be declared by a judicial or other competent authority to be unenforceable, the remaining provisions of the Agreement shall remain in full force and effect.

26.9 The Parties acknowledge that this Agreement and all related documents shall be in English.

26.10 This Agreement may be executed by the Parties in counterparts, each of which when so executed and delivered shall be deemed to be an original and when taken together shall be deemed to be one and the same instrument. The electronic delivery, including, without limitation, by email or facsimile transmission, of any signed original of this Agreement shall be the same as the delivery of an original.

27. SURVIVAL

27.1 Subject to the provisions of the Act, all provisions of this Agreement which by their express terms or nature are continuing shall survive the expiration or termination of this Agreement, including, without limitation, this provision, and the provisions relating to the EECA Plan (s. 3.2), EfficiencyOne's covenants (s.9), confidentiality (s. 11), indemnity (s.14), intellectual property (s. 17), notification (s. 21) and general provisions (s. 26) as well as any provisions which are required to determine, or which exclude or limit, any liability or which are otherwise required to give effect to or interpret any such provisions which are continuing.

[Remainder of page intentionally left blank]

1 **IN WITNESS THEREOF**, the Parties have duly executed this Agreement, in duplicate, as of the
2 date set forth above.

NOVA SCOTIA POWER INCORPORATED

Per:

Name:

Title:

Witness

Per:

Name:

Title:

Witness

EFFICIENCYONE

Per:

Name:

Title:

Witness

Per:

Name:

Title:

Witness

3

4

SCHEDULE A

ELECTRICITY EFFICIENCY AND CONSERVATION ACTIVITIES

Schedule A

Electricity Efficiency and Conservation Activities

The figure below identifies the scope of savings (3 year Cumulative Annual Energy Savings and Cumulative Annual Peak Demand Savings) associated with carrying out EECAs over the Term.

	Cumulative Annual Net Energy Savings at Generator over the Term (GWh)	Cumulative Annual Net Peak Demand Savings at Generator over the Term (MW)	Lifetime Energy Savings (GWh)
Performance Targets*			

The Performance Targets will be achieved in accordance with the EECA Plan as set out in Schedule E.

* For certainty, in accordance with the performance requirements set out in Schedule "C" attached hereto, EfficiencyOne shall be deemed to be in substantial compliance with the approved Performance Targets if the stipulated 90 percent level of achievement is reached on each Performance Targets. If less than the stipulated 90 percent level any of the Performance Targets is achieved, a regulatory process will be triggered.

**

SCHEDULE B

COMPENSATION

Schedule B (Page 1 of 2)

Compensation

I. Net Contract Price

The figure below identifies the Contract Price to be paid by NSPI allocated for each year of the Term.

		<u>2020-2023</u>	<u>2021-2024</u>	<u>2022-2025</u>
UARB Approved Investment Amount				
~~2016-2020 - 2018-2022~~ DSM Plan Underspend				
Net Contract Amount to be Paid by NSPI				

The Parties acknowledge that any surplus realized by EfficiencyOne in delivering the Performance Targets at the end of the Term shall be reported to the UARB and refunded to NSPI¹ unless EfficiencyOne is directed to do otherwise by the UARB.

~~EfficiencyOne has returned the bank interest earned of \$246,630 (included in the 2016-2018 DSM Supply Agreement underspend of \$7,508,216) in 2018 (\$45,440) and in 2019 (\$201,190). Therefore, the underspend applied to 2020 will be \$7,261,586.~~

¹ Together with all accumulated interest earned by EfficiencyOne on such surplus.

Schedule B (Page 2 of 2)

Compensation

II. Payments

In accordance with Section 4.3 of the Agreement, the monthly payments to be made by NSPI to EfficiencyOne over the Term shall be as set out below. The monthly payment amounts referred to following are exclusive of required HST. HST shall be remitted to EfficiencyOne in addition to these monthly amounts.

On the First Business Day of:	~~2020~~ 2023	~~2021~~ 2024	~~2022~~ 2025
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
Total			

SCHEDULE C

Performance Requirements

I. UARB-APPROVED PERFORMANCE TARGETS, THRESHOLDS, AND INDICATORS

a) Performance Targets and Thresholds:

- i. Performance Targets are set over the three year contract period, rather than annually.
- ii. EfficiencyOne is deemed to be in substantial compliance with the UARB-approved Plan Performance Targets if ninety percent (90%) or greater achievement is reached on the cumulative annual net energy savings at generator and cumulative net peak demand savings at generator Performance Targets listed at b) i and ii below. If less than ninety percent (90%) of either Performance Target at b) i and ii below is achieved, a regulatory process will be triggered.

b) Performance Targets consist of:

- i. Cumulative annual net energy savings at generator
- ii. Cumulative annual net peak demand savings at generator

c) Performance Indicators (for UARB reporting) consist of:

- i. Annual incremental energy savings (reported by program and rate class);
- ii. Cumulative annual energy savings (reported by program and rate class);
- iii. Annual lifetime energy savings (reported by program and rate class);
- iv. Cumulative lifetime energy savings (reported by program and rate class);
- iv. Annual incremental system-peak demand savings (reported by program and rate class);
- v. Cumulative annual system-peak demand savings (reported by program and rate class);
- vi. Annual demand savings attributable to demand response activities
- vi. Total ratepayer benefits;
- vii. Total spending (reported by program and rate class);
- viii. Customer satisfaction; and
- ix. An analysis of the impact on rates through the implementation of the programs will be included as part of EfficiencyOne's historical-looking rate and bill impact analysis, filed by October 31st of each year; and

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- x. Reporting on low-income program participation, expenditures, and savings through a variety of methods, including estimation based on geographic census information.

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SCHEDULE D

CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT

THIS CONFIDENTIALITY AGREEMENT made effective this 1st day of January,
2020-2023

Between:

EfficiencyOne, hereinafter "EfficiencyOne"

Party of the First Part

And

Nova Scotia Power Incorporated, hereinafter "NSPI"

Party of the Second Part

Whereas the Parties have entered into a Supply Agreement for Electricity Efficiency and Conservation Activities made effective as of January 1, 2020-2023 ("Supply Agreement") whereby Efficiency One is to provide EECA (as that term is defined in the Supply Agreement) to NSPI;

And whereas in accordance with the Supply Agreement, and the Electricity Efficiency and Conservation Act (Nova Scotia) and the Public Utilities Act (Nova Scotia) (together hereinafter referred to as the "Legislation"), and as may be directed by the Nova Scotia Utility and Review Board, and as may be further agreed between the Parties, the Parties will be receiving, reviewing, and analyzing Confidential Information from each other;

And whereas the Parties wish to clarify the manner in which any Confidential Information disclosed by one Party ("Disclosing Party") to the other is to be treated by the recipient of the Confidential Information ("Recipient");

In consideration of the agreements of the Parties set forth below, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1

2 **Confidential Information**

3 1. The Parties agree that for the purpose of this Agreement "Confidential
4 Information" means all information, regardless of the form in which it is
5 communicated or maintained and prepared by the Disclosing Party, and is
6 disclosed directly or indirectly to the Recipient, pursuant to the Supply
7 Agreement, the Legislation, as directed by the Nova Scotia Utility and Review
8 Board or as otherwise agreed between the Parties. Confidential Information
9 includes, but is not limited to the following: all reports analyses, notes,
10 memoranda, correspondence, spreadsheets, drawings, survey plans, maps,
11 contracts, commercial arrangements, intellectual property, trade secrets,
12 corporate strategies, business plans or other information that is based on,
13 contain or reflect any Confidential Information, material, whether printed or
14 electronic, which has been designated by the Disclosing Party as confidential
15 information, including proprietary information and other commercially sensitive
16 information. This includes but is not limited to information which has been or
17 may be filed with the Nova Scotia Utility and Review Board ("the Board") in
18 confidence in answer to Information Requests and any further material that may
19 be filed with the Board in confidence whether in response to future Information
20 Requests or otherwise, and whether printed or electronic. Confidential
21 Information shall also include any explanation or other information provided by
22 either Party to the Recipient concerning the foregoing and which has been
23 identified by the Party providing the information as confidential at the time it is
24 initially provided, whether printed or electronic. Confidential Information may also
25 include any password or other information necessary to access electronic copies
26 of Confidential Information.

27 **Permitted Scope of Use**

28 2. The Recipient may use the Confidential Information solely for the purposes of
29 providing or receiving EECA, as the case may be, in accordance with the
30 Legislation and the Supply Agreement and for no other reason or purpose.

31 **No Obligation to Disclose**

32 3. This Agreement does not obligate either Party to disclose any Confidential
33 Information to the other.

34 **Protection of Confidential Information**

35 4. The Recipient shall hold the Confidential Information in strict confidence and
36 shall strictly protect the Confidential Information from all harm, loss, theft,
37 reproduction and unauthorized access, employing at least the same degree of
38 care that the Recipient employs to protect its own confidential information of a
39 similar nature, but in any event, not less than reasonable care. The Recipient
40 shall ensure that such Confidential Information is not disclosed, published,

1 released, transferred or otherwise made available in any form to, for the use or
2 benefit of, any person except as provided in this Agreement.

3 **Acknowledgements**

4 5. The Recipient acknowledges that the Confidential Information is confidential and
5 a trade secret and is owned by the Disclosing Party and is highly valuable and
6 material to the interests, business and affairs of the Disclosing Party and that any
7 unauthorized disclosure thereof by the Recipient would be detrimental to the
8 Disclosing Party.

9 **Permitted Disclosures**

10 6. The Recipient shall be permitted to disclose relevant aspects of the Confidential
11 Information to its employees and professional advisors to the extent that such
12 disclosure is reasonably necessary for the performance of its duties and
13 obligations; provided, however, that prior to such disclosure the Recipient shall
14 inform such persons and parties of the confidential nature of the Confidential
15 Information and each such person or party signs the undertaking attached to this
16 Confidentiality Agreement. The Recipient shall inform the Disclosing Party of the
17 name of each person to whom it has disclosed the Confidential Information in
18 accordance with this provision and shall provide to the Disclosing Party the
19 signed undertaking. The Recipient shall be fully responsible for ensuring that
20 any such persons to whom it discloses the Confidential Information complies with
21 the confidentiality obligations contained in this Agreement and shall be liable for
22 any breach of this Agreement by such persons.

23 7. The non-disclosure obligations in this Agreement shall not restrict any disclosure
24 by the Recipient pursuant to any applicable law or an order of any court of
25 competent jurisdiction or regulatory body with regulatory responsibilities over the
26 Recipient, provided that the Recipient shall provide the Disclosing Party with
27 prompt prior written notice of its obligation to disclose so that the Disclosing Party
28 may seek a protective order or other appropriate remedy concerning the
29 disclosure of its Confidential Information and/or waive compliance with the
30 confidentiality provisions of this Agreement. In addition, the Recipient shall take
31 reasonable steps, to the extent permitted by law, to remove from the Confidential
32 Information that is required to be disclosed, any information that is commercially
33 sensitive to the Disclosing Party. In the event of an order for disclosure by a court
34 of competent jurisdiction or regulatory body with regulatory responsibilities over
35 the Recipient, the Recipient shall first notify the Disclosing Party of such order
36 and allow the Disclosing Party not less than ten (10) days to remove any such
37 information that is commercially sensitive.

38 **Term**

39 8. The term of this Agreement shall commence on the effective date of the Supply
40 Agreement unless superceded by another form of writing, and notwithstanding
41 the return of any Confidential Information or any other event, shall continue in full

1 force and effect for a period of FIVE (5) years from the effective date of this
2 Agreement.

3 **Equitable Remedy**

4 9. The Recipient acknowledges that any unauthorized use of the Confidential
5 Information or any breach of its obligations under this Agreement will result in
6 irreparable harm to the Disclosing Party which cannot be adequately
7 compensated for by damages. Neither the Recipient, nor any term in this
8 Agreement, shall interfere with, delay, or prevent the Disclosing Party from
9 seeking an interim and interlocutory equitable remedy to enforce any provision of
10 this Agreement. The Recipient agrees not to oppose an application for equitable
11 relief by the Disclosing Party in such circumstances. Any such relief or remedy
12 shall not be exclusive, but shall be in addition to all other available legal or
13 equitable remedies. The Recipient agrees that the provisions of this Section are
14 fair and reasonable in the commercial circumstances of this Agreement. This
15 Article shall survive the termination of this Agreement.

16 **Return of Information**

17 10. On the earlier of either thirty (30) days following the termination of the Supply
18 Agreement or at the written request of the Disclosing Party (and unless
19 superceded by another form of writing), the Recipient shall return or destroy (at
20 the Disclosing Party's direction) and delete from all electronic devices all
21 Confidential Information provided to it, including all copies (and all notes and
22 documents prepared by the Recipient that may incorporate same) and still in the
23 Recipient's possession (and otherwise under its control or in the possession of
24 other persons to whom it has been provided as permitted hereunder) and, if
25 requested by the Disclosing Party, shall provide written confirmation to the
26 Disclosing Party to that effect. Notwithstanding the forgoing, the Recipient shall
27 be entitled to retain the Confidential Information in one legal file copy that may be
28 retained solely for the determination of its legal obligations under this Agreement.

29 **Residual Information**

30 11. The Recipient or its designate or any other person having access to the
31 Confidential Information pursuant to this Agreement shall not, during and after
32 the termination of this Agreement, use in its business any Residual Information.
33 "Residual Information" means the ideas, know-how and techniques that would be
34 retained in the unaided memory of an ordinary person skilled in the art, not intent
35 on appropriating the proprietary information of the disclosing party, as a result of
36 such person's access to, use, review, evaluation, or testing of the Confidential
37 Information of the disclosing party for the purposes described herein. An
38 employee's memory is unaided if the employee has not intentionally memorized
39 the Confidential Information for the purpose of retaining and subsequently using
40 or disclosing it.

Limited Rights

12. The Recipient agrees that no rights are granted to Recipient other than the limited rights to use the Confidential Information on the terms of this Agreement. For certainty, no license is granted under this Agreement (directly or indirectly) under any patent, discovery, copyright, or other intellectual or industrial property right now or in the future.

Indemnity

13. The Recipient shall indemnify and hold the Disclosing Party harmless from any and all loss, liability, cost or expense (including, without limitation, solicitor's costs on a solicitor and client basis and all other costs of defence) caused in whole or in part by the Recipient's breach of any provision of this Agreement. This Article shall survive the termination of this Agreement.

Governing Law

14. This Agreement is governed and shall be construed in accordance with the laws of the Province of Nova Scotia.

General Provisions

15. This Agreement is binding on the Parties, their administrators, successors, executors and assigns.

Executed and delivered this day of 20 .

EfficiencyOne

Nova Scotia Power Incorporated

By: _____

By: _____

Name:

Name:

Title:

Title:

SCHEDULE "A" to CONFIDENTIALITY AGREEMENT

UNDERTAKING

I _____, HAVE READ AND
AGREE TO ABIDE AND AM BOUND BY THE TERMS AND CONDITIONS SET
OUT IN THE CONFIDENTIALITY AGREEMENT DATED THE ____ DAY OF
____ BETWEEN EFFICIENCYONE AND NOVA SCOTIA
POWER INCORPORATED.

Dated the ____ day of _____ 201 .

Witness

Name:

Recipient Designate

SCHEDULE E

EECA PLAN

[Subject to approval by the UARB]

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