Request IR-01:

Has E1 conducted a risk assessment related to its cyber security? If so, please describe. [MAY REQUIRE CONFIDENTIAL RESPONSE]

Response IR-01:

[redacted]

[redacted]

Request IR-02:

(a) How does E1 protect the personal information of customers within E1's activities? [MAY REQUIRE CONFIDENTIAL RESPONSE]

(b) How does E1 protect personal information of customers in its dealings with third parties? [MAY REQUIRE CONFIDENTIAL RESPONSE]

Response IR-02:

(a) [redacted]

(b) [redacted]

Request IR-03:

Does E1 currently have cyber insurance coverage? If so, please describe this coverage. [MAY REQUIRE CONFIDENTIAL RESPONSE]

Response IR-03:

[redacted]

Request IR-04:

Regarding complaints, for the years 2020 to 2025 year-to-date:

(a) Please state how many complaints were received each year.

(b) For each year, please identify the percentage of those complaints that were related to regulated and to non-regulated programs and identify the percentages raised by customers and by contractors.

(c) Does E1 consider that complaints related to non-regulated programs may have an impact on the success or effectiveness of regulated programs? Please elaborate.

(d) If E1 is not able to satisfactorily resolve a complaint, what process is available to the complainant for resolution?

(e) Does E1 have a written policy or practice for complaint resolution? If so, please file a copy of that document.

Response IR-04:

(a) EfficiencyOne (E1) implemented customer complaints tracking in 2022 through its Customer Information System and does not have comparable tracked data on complaints prior to 2022. For its tracking purposes, E1 defines complaints as any time a customer expresses dissatisfaction with any aspect of an E1 program or service at any point in their engagement with E1 – from pre-application to program completion; as well as concerns from people who never participate in a program. Using that definition, the total number of complaints (for both regulated and non-regulated programs) received by E1 from 2020-2025 are as follows:

- Q1 2025 (Jan. 1 – March 31, 2025): 2,100
- 2024: 3,596
- 2023: 1,652
- 2022: 1,400

The increase in the number of overall complaints is proportional to the overall growth and demand for E1 program offerings over the last three years. Key drivers of the growth include the increase in the number of non-regulated funding sources and streams, including federal programs. From 2022 to 2024, the number of customers supported by E1 has grown from under 50,000 to over 200,000 annually (excludes residential Instant Savings, Business Energy Rebates-Instant Rebates and includes Residential Behaviour).

E1's records on the number of complaints from contractors date back to August 2021. There have been a total of 49 complaints received from contractors between August 2021 and March 2025 and are not distinguished between regulated and non-regulated programs.

(b) E1 tracks customer complaints by program component in its Customer Information System. For program components where there are both regulated and non-regulated funding and participation, the total number of complaints is tracked, but they are not categorized by type of participant (i.e., whether a participant is from the regulated side of the program component or the non-regulated side). In the course of resolving any complaint, E1 can identify whether an individual is participating in the regulated or non-regulated side of a program component, but it is not part of overall customer complaint tracking at E1. A complainant also may not be a participant in an E1 program.

(c) The resolution of complaints related to both its regulated and non-regulated programs is a key priority for E1, as the reputation of E1 and its programs is critical to the organization achieving its Performance Targets and overall mission. Complaints from participants in both regulated and non-regulated E1 programming are resolved through the same process.

(d) E1 has an established complaint resolution process for handling and resolving all types of complaints (wait times, rebate amounts, rebate processing times, program eligibility, concerns about service providers, etc.). It is described in an internal process document which has been included as Attachment 1 to this IR. If a complaint cannot be resolved by frontline E1 customer service and program staff, there is a tiered escalation process in place to bring it to the attention of senior management at E1, as required, in order to resolve complaints as quickly as possible. If a customer is not satisfied with how their complaint has been handled, they can request that it be reviewed by E1's appeals and dispute officer, who can be reached by email at appeals@efficiencyns.ca. This contact information is available on the Efficiency Nova Scotia website under Appeals and Dispute Resolutions Efficiency Nova Scotia.

(e) Please refer to part (d) of this IR response.

EFFICIENCYONE - CASE MANAGEMENT PROCESS

EfficiencyOne department: All departments	Process: Case Management
Issue Year: 2022; updated 2025	Enabling System: Customer Information System (CIS)

SCOPE

The purpose of this process is to provide consistent, accurate and timely information to our customers when they make inquiries or complaints. Our priority is to deliver efficient and quality handoffs to facilitate a more effective case management process thereby:

- Reducing follow-ups and contact between various business units.
- Improving process efficiency
- Improving service to the customer

To achieve this goal every program and department must be working together.

ACCOUNTABILITY

The undersigned parties agree to the roles and expectations defined in this document and are accountable for ensuring that their respective business functions adhere to them.

Name: ______________________________________

Role: ____

RESPONSIBILITIES

ACTION	EXPECTATION
Customer service	All customers to be treated with respect, fairness, understanding and courtesy.
Case creation	Cases are created upon initial contact with customer. • Trouble shoot with customer to determine needs. • Utilize all resources to answer customer inquiry/complaint. If customer is not satisfied at current Tier level, case to be re-assigned to next Tier level.
Response times	Assignee to take ownership of case they are assigned responding to customer within 2-5 business days with update via call or email
Record details	Assignee to ensure adequate and complete detail is provided in consistent format within the case.

ACTION	EXPECTATION
Follow-up	Should any actions be required to ensure customer satisfaction, assignee will follow up with customer to confirm such actions were completed. **For example, if a Service Provider is to return to the home to complete work, assignee will contact customer to confirm work was completed satisfactorily.*
Escalate case as required	Cases can be re-assigned as needed. If complaint can not be solved at current Tier level, case to be re-assigned to next Tier level. **Once a complaint is assigned to a higher Tier level it can not be re-assigned to a lower Tier.*

ESCALATION LEVELS (TIERS)

TIER LEVEL	EMPLOYEE CATEGORIES
Tier 1	• Energy Solutions Advisors • Business Development Managers • Energy Managers • Program Coordinators • Efficiency Specialists • Quality Assurance Specialists • Coordinators • Administrative Assistants
Tier 2	• Program Managers • Efficiency Preferred Partner (EPP) Manager Leads
Tier 3	• Service Delivery Managers • Business Development Manager Leads • Field Engineer Managers • Services Support Managers
Tier 4	• Senior Directors • Vice-presidents
Tier 5	• Officer • Chief Operating Officer • Chief Executive Officer

APPEALS OR DISPUTE RESOLUTION (New as of 2025)

If a customer believes that a complaint has not been sufficiently resolved after contacting our Energy Solutions Advisor Team, they can contact our Appeals and Dispute Officer for further assistance at appeals@efficiencyns.ca.A customer complaint must have been addressed through our Energy Solutions Advisors first, in order to be considered for review by the Appeals and Dispute Officer.

Request IR-05:

(a) Please file a copy of E1's organizational chart.

(b) Please state the total employee complement for each of the past 5 years. Please note whether that number includes only full-time employees or if it includes any part-time or other FTEs.

Response IR-05:

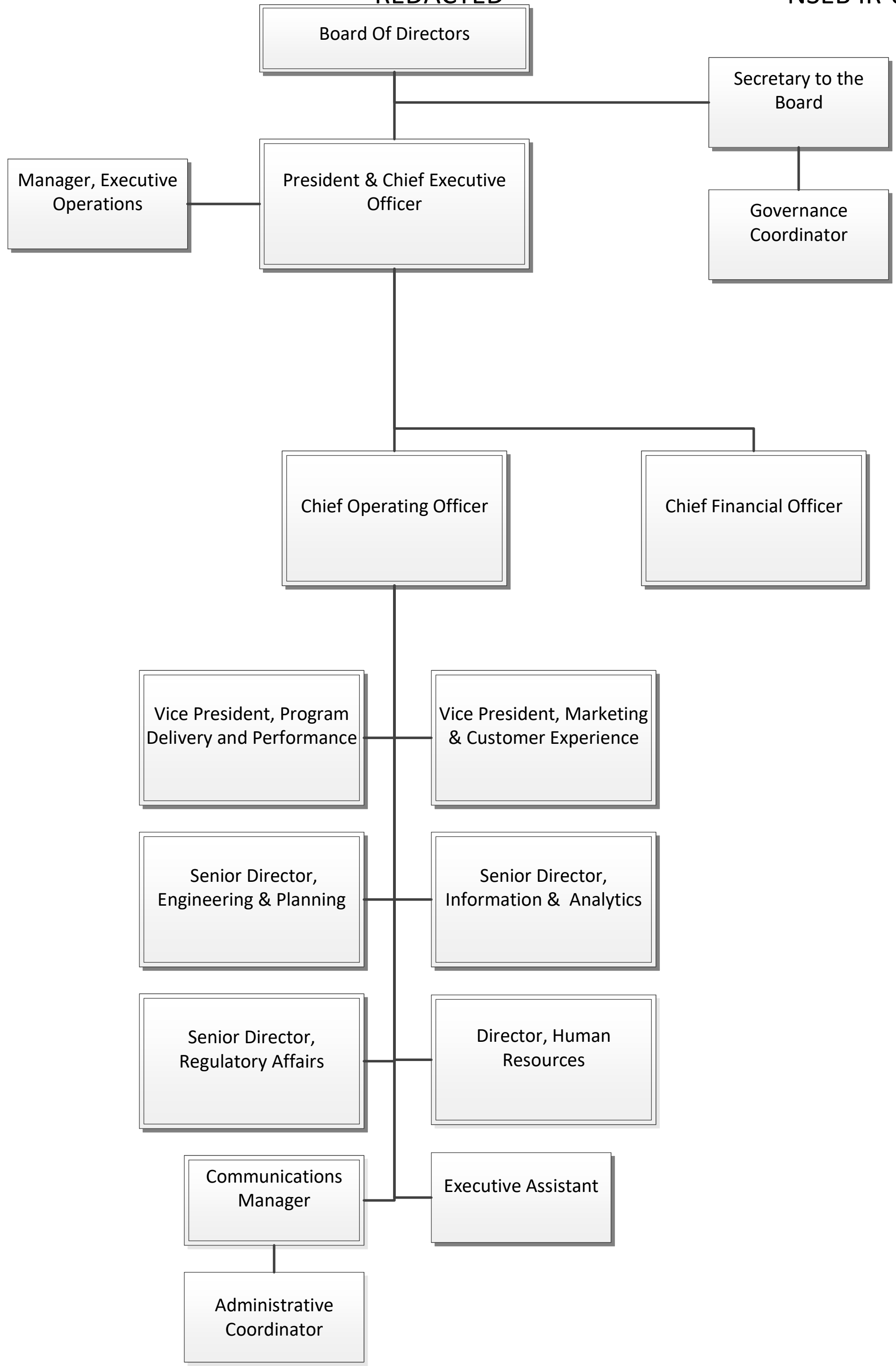
(a) EfficiencyOne's (E1) current organizational chart has been provided as Attachment 1 to this IR response. Please note that the organizational chart provided is not limited to only those positions that support only DSM activities; rather it includes all E1 operations.

(b) The table below represents the number of full time equivalent (FTEs) employees that were assigned to DSM activities at the end of each year by department. The FTEs below represent only full-time employees. E1 did not have any part-time employees during these years.

	2020	2021	2022	2023	2024
Program Delivery and Performance	31.0	33.9	34.0	40.9	38.2
Marketing and Customer Experiences	22.0	22.2	22.0	28.0	32.8
Regulatory Affairs	2.8	4.4	3.8	4.3	5.5
Engineering & Planning	5.9	8.8	10.2	11.7	9.9
Finance	4.5	4.5	4.7	5.6	6.7
Human Resources	2.6	2.6	3.2	3.4	2.8
Corporate Services	1.9	2.9	3.2	3.1	3.1
Information and Analytics	3.2	4.2	4.4	5.6	5.2
Information Systems and Technology	1.6	1.9	1.9	2.0	2.6
DSM Share of FTE	75.5	85.4	87.4	104.6	106.8
DSM Salaries & Benefits as a % of Total DSM Expenditures	22.8%	22.4%	20.4%	21.2%	17.0%
DSM Total Expenditures per FTE	$376,300	$421,600	$488,700	$432,800	$615,600

EfficiencyOne

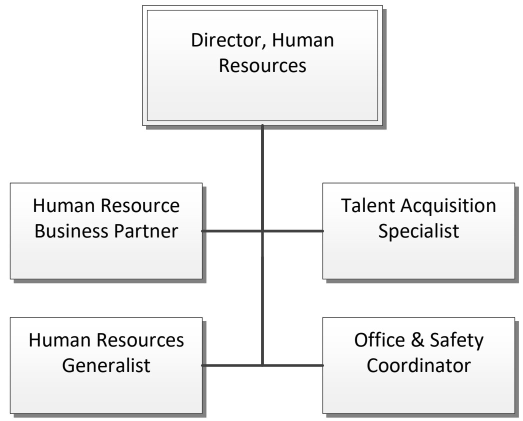
2025



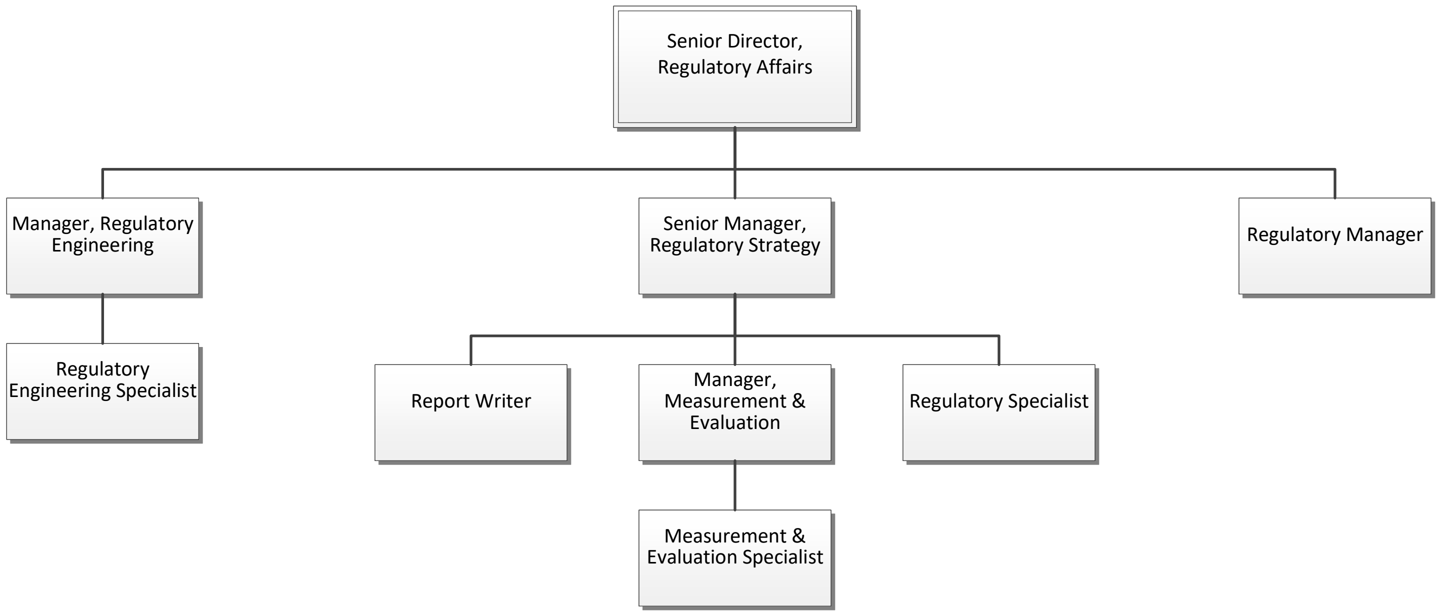
EfficiencyOne

2025

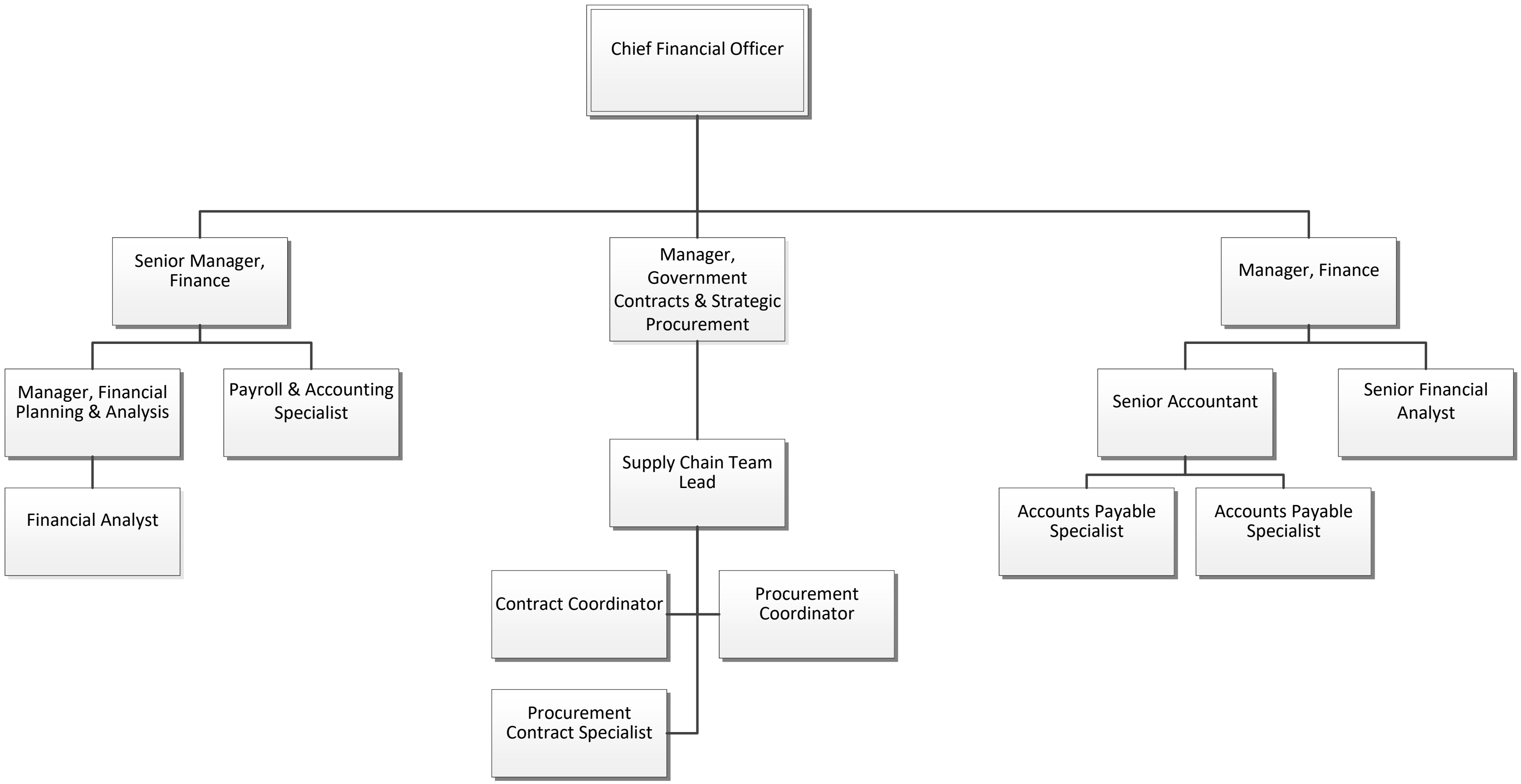
Human Resources



EfficiencyOne
2025
Regulatory



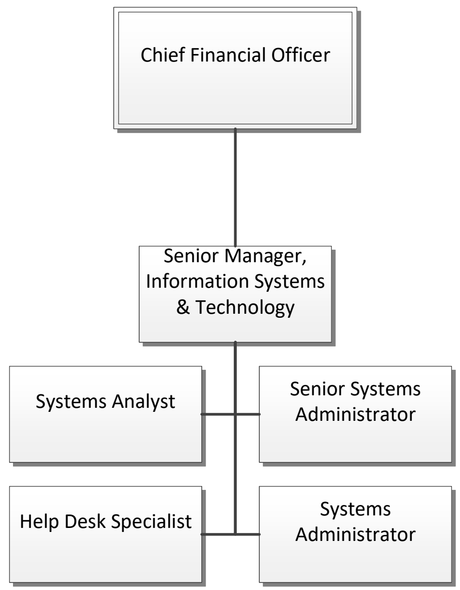
EfficiencyOne
2025
Finance



EfficiencyOne

2025

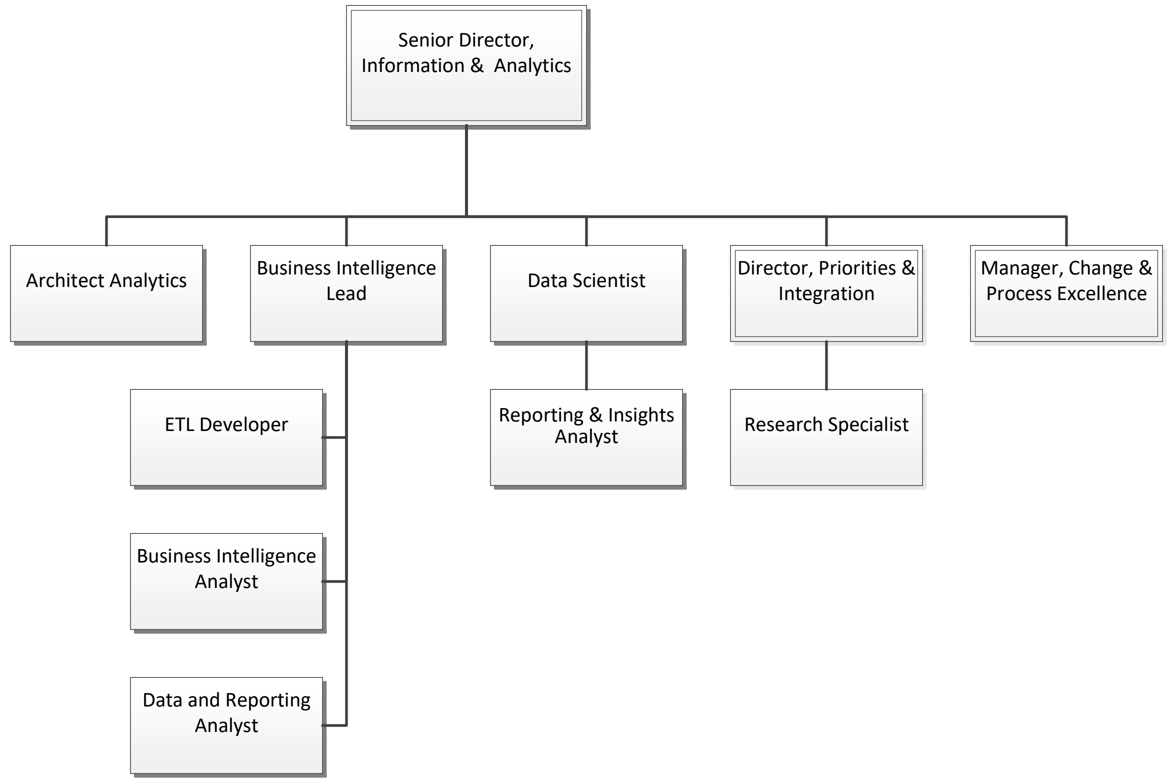
IT & Infrastructure



EfficiencyOne

2025

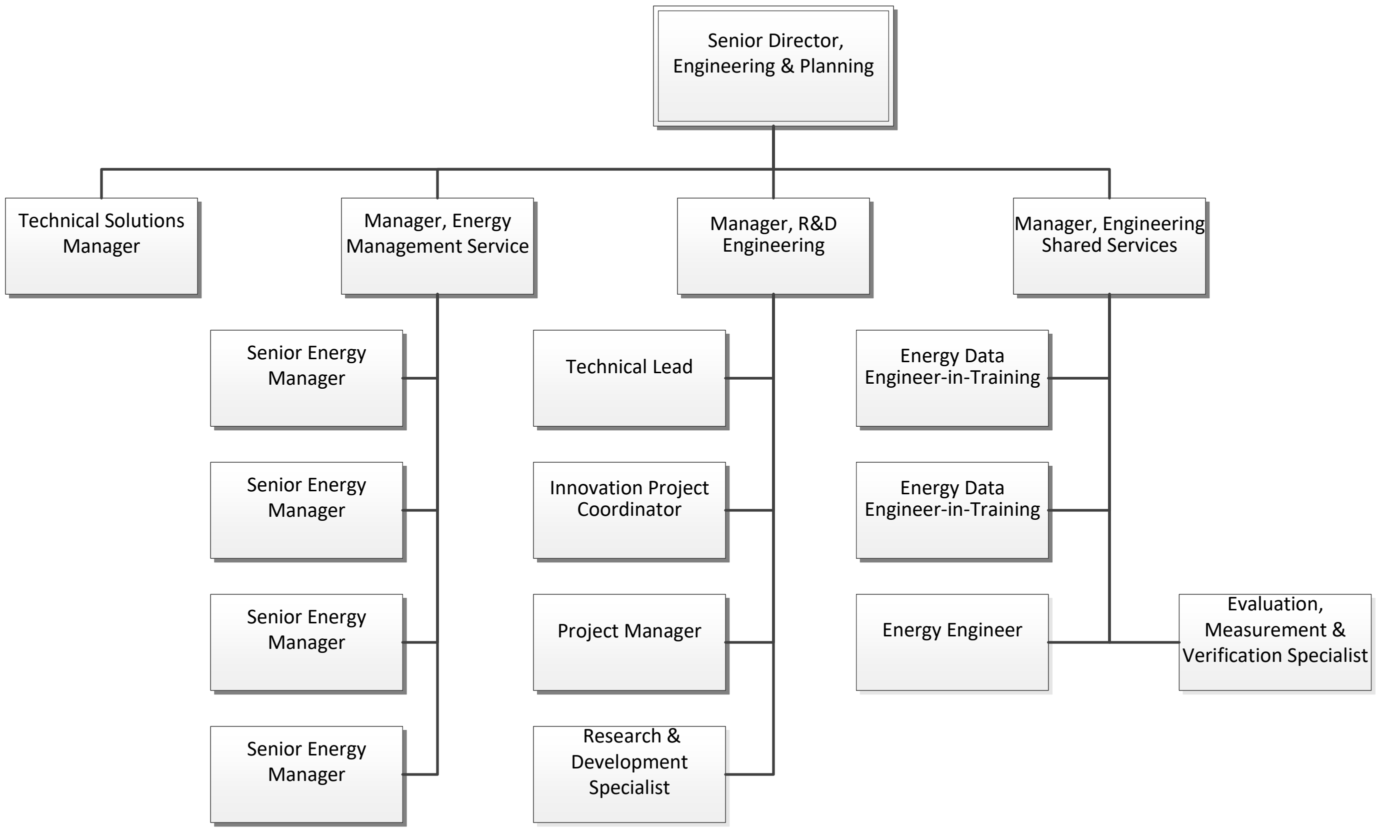
Information & Analytics



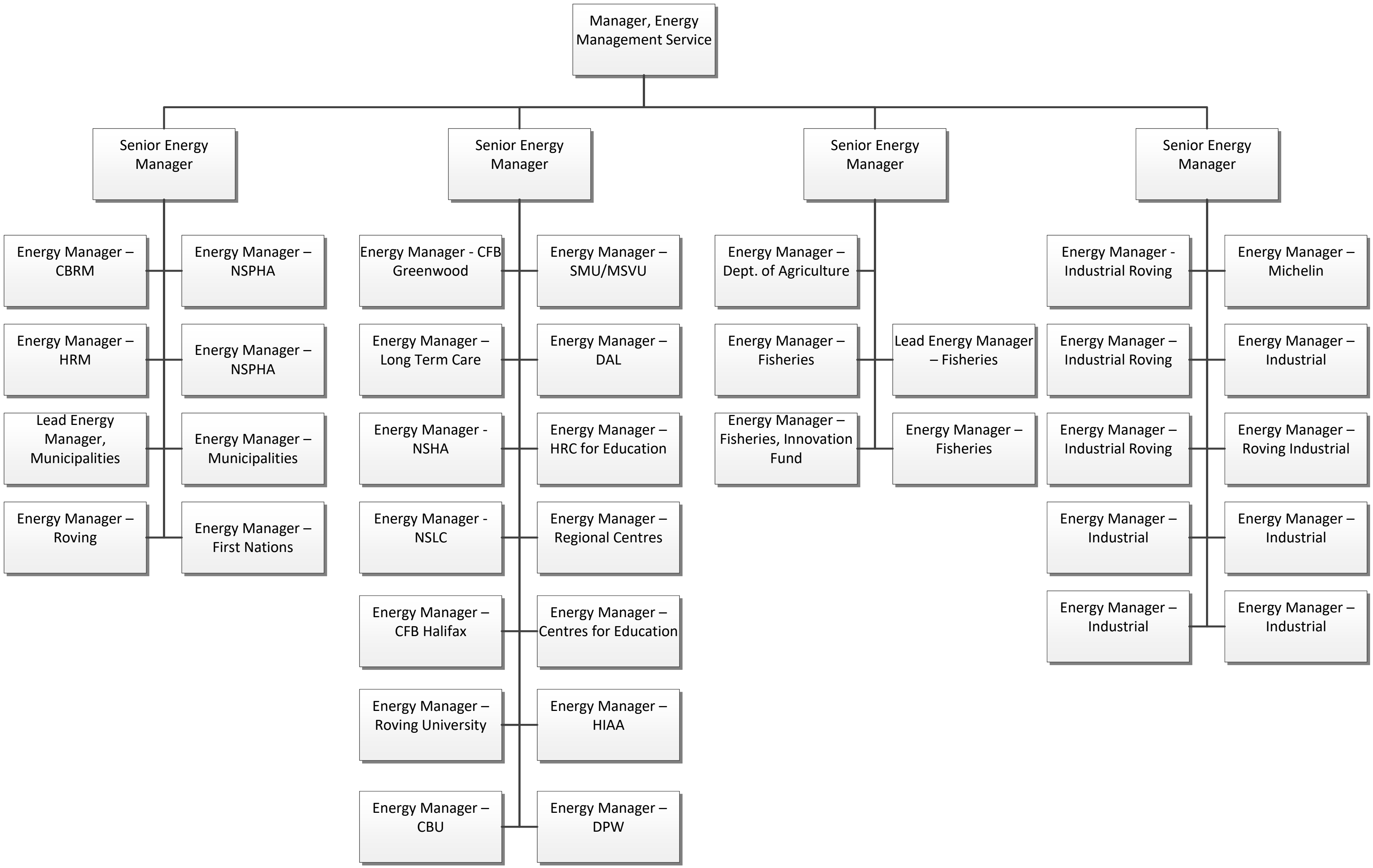
EfficiencyOne

2025

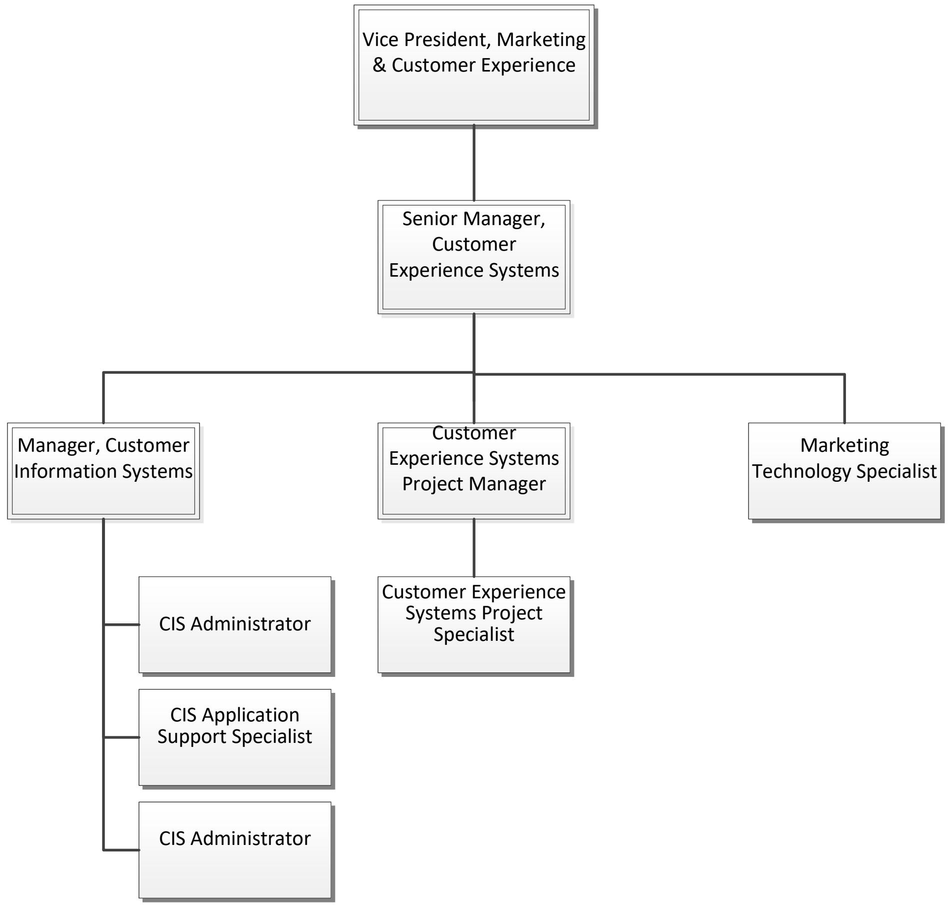
Engineering & Planning



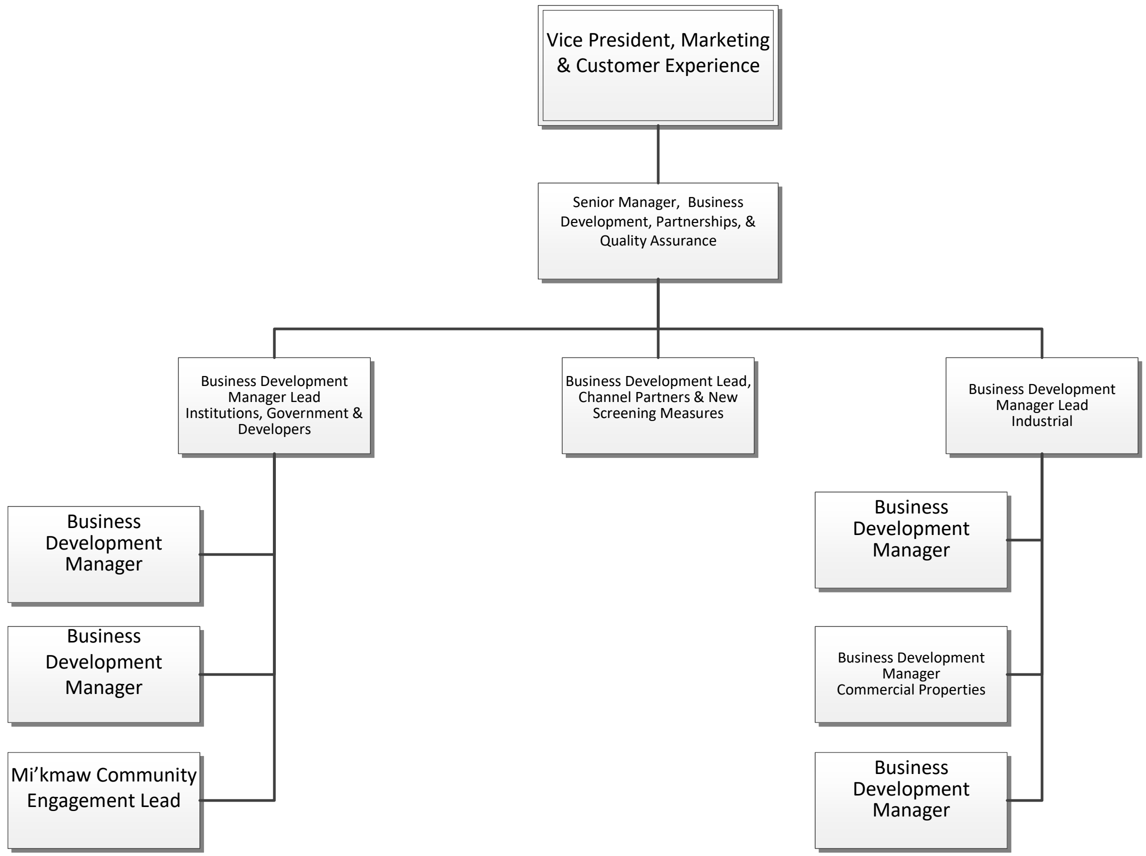
EfficiencyOne
2025
Engineering & Planning – Energy Managers



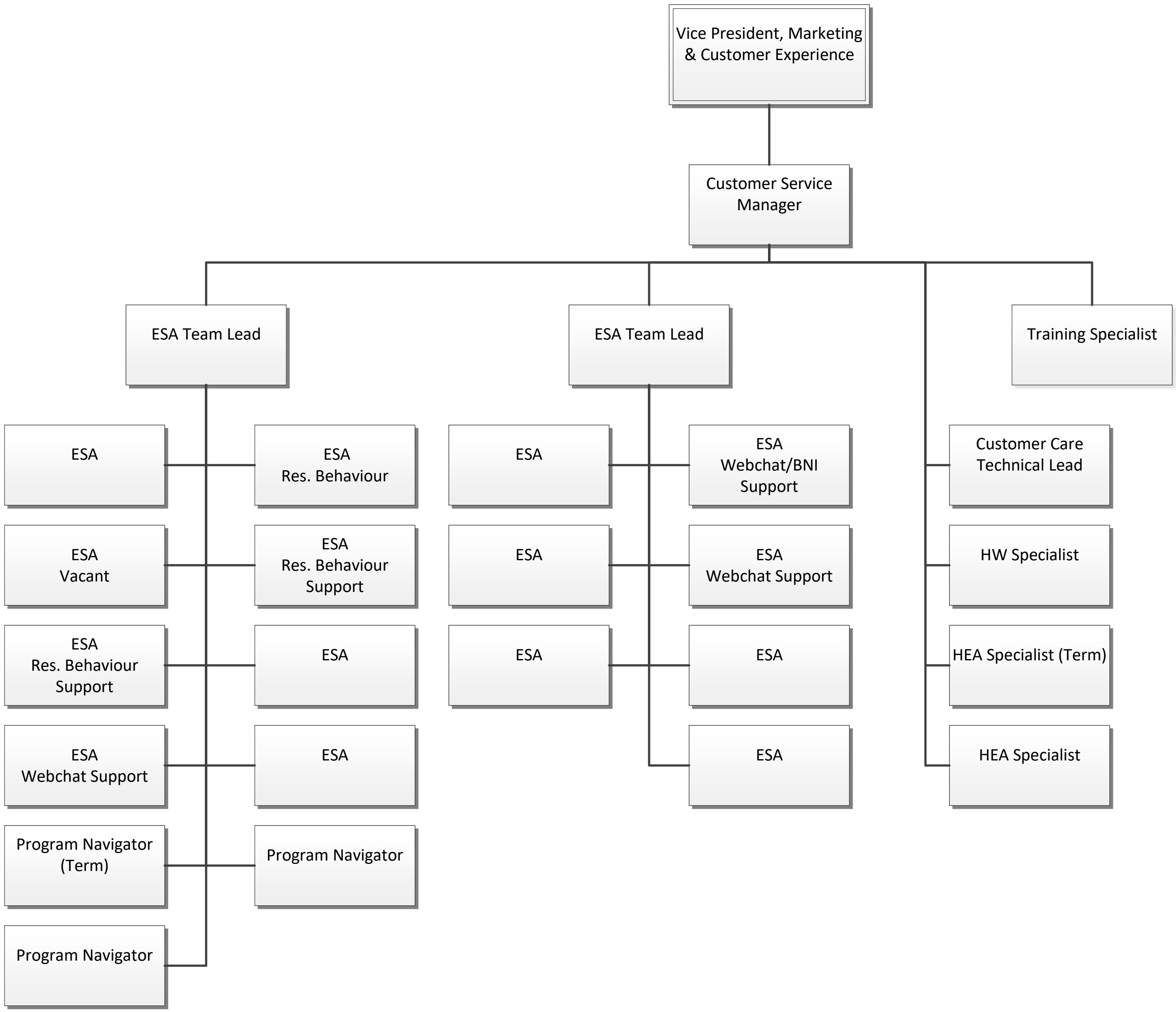
EfficiencyOne
2025
Customer Experience Systems



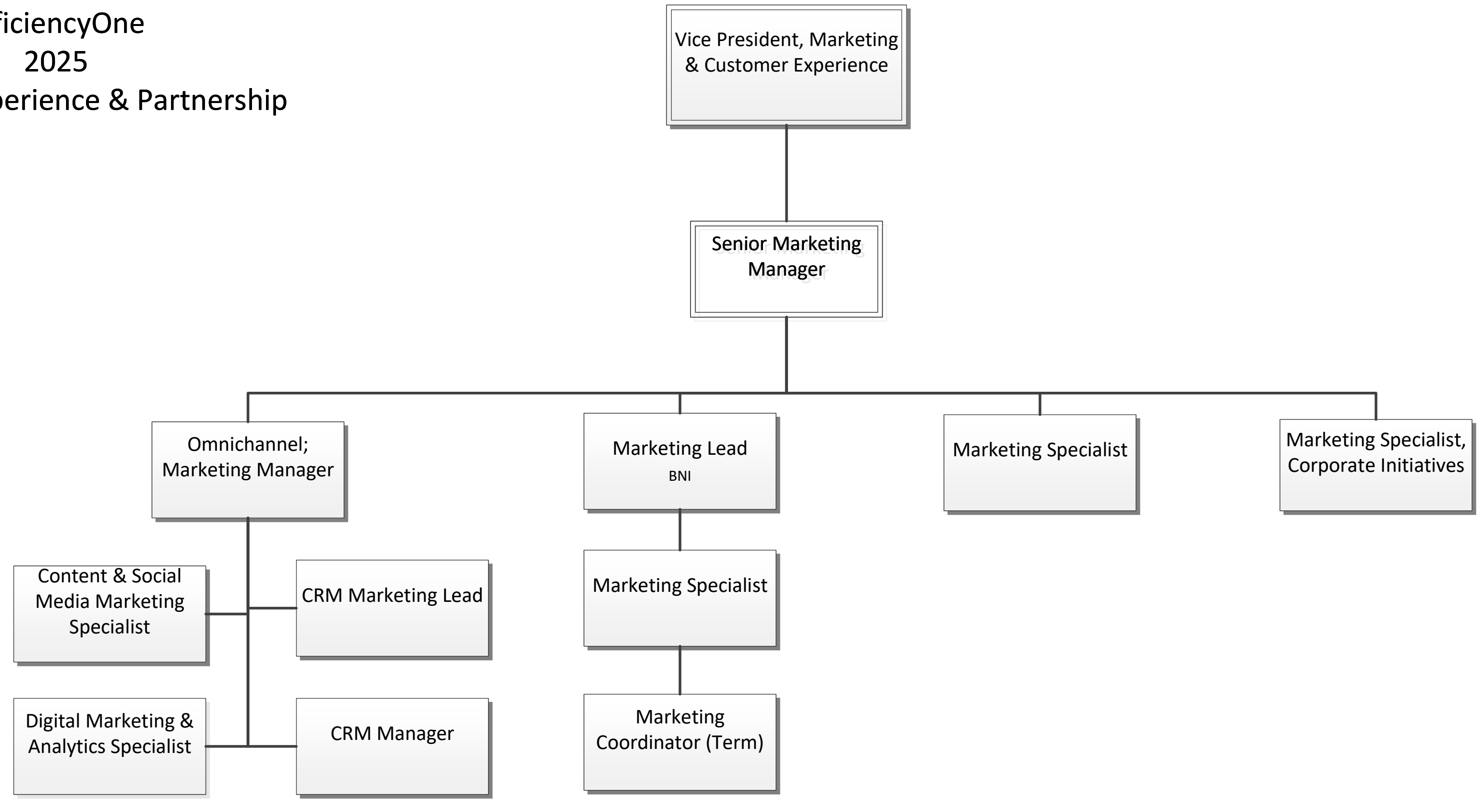
EfficiencyOne
2025
Business Development



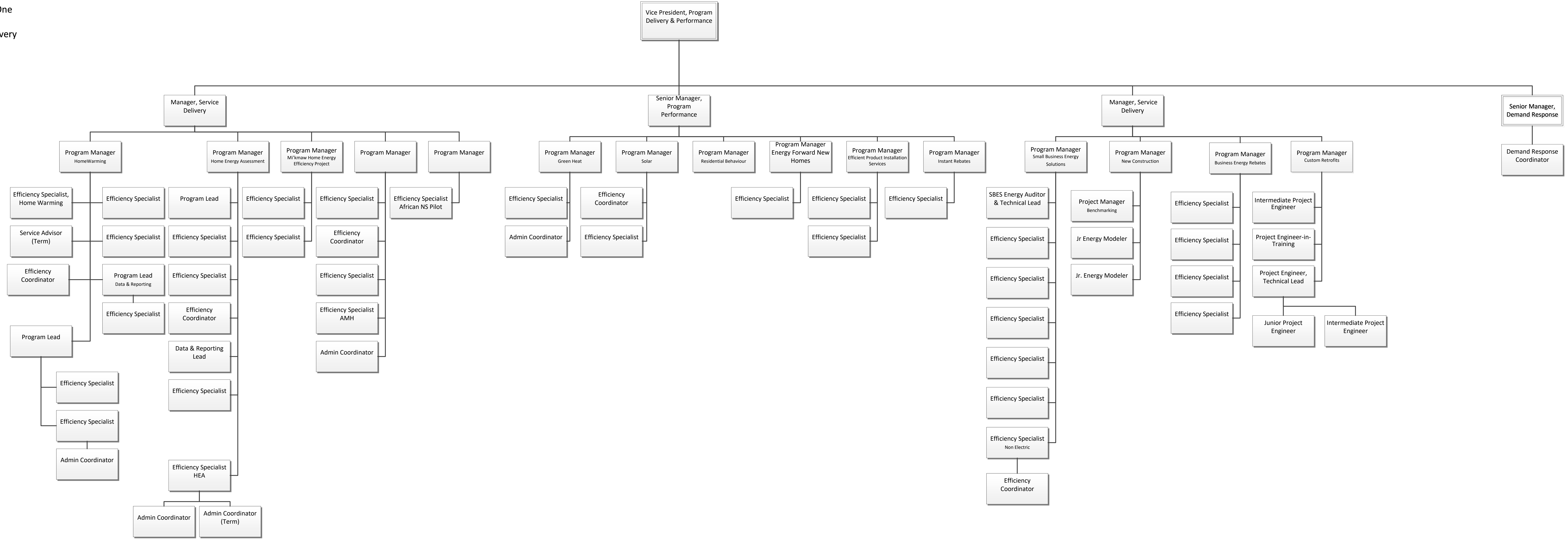
EfficiencyOne
2025
Customer Service



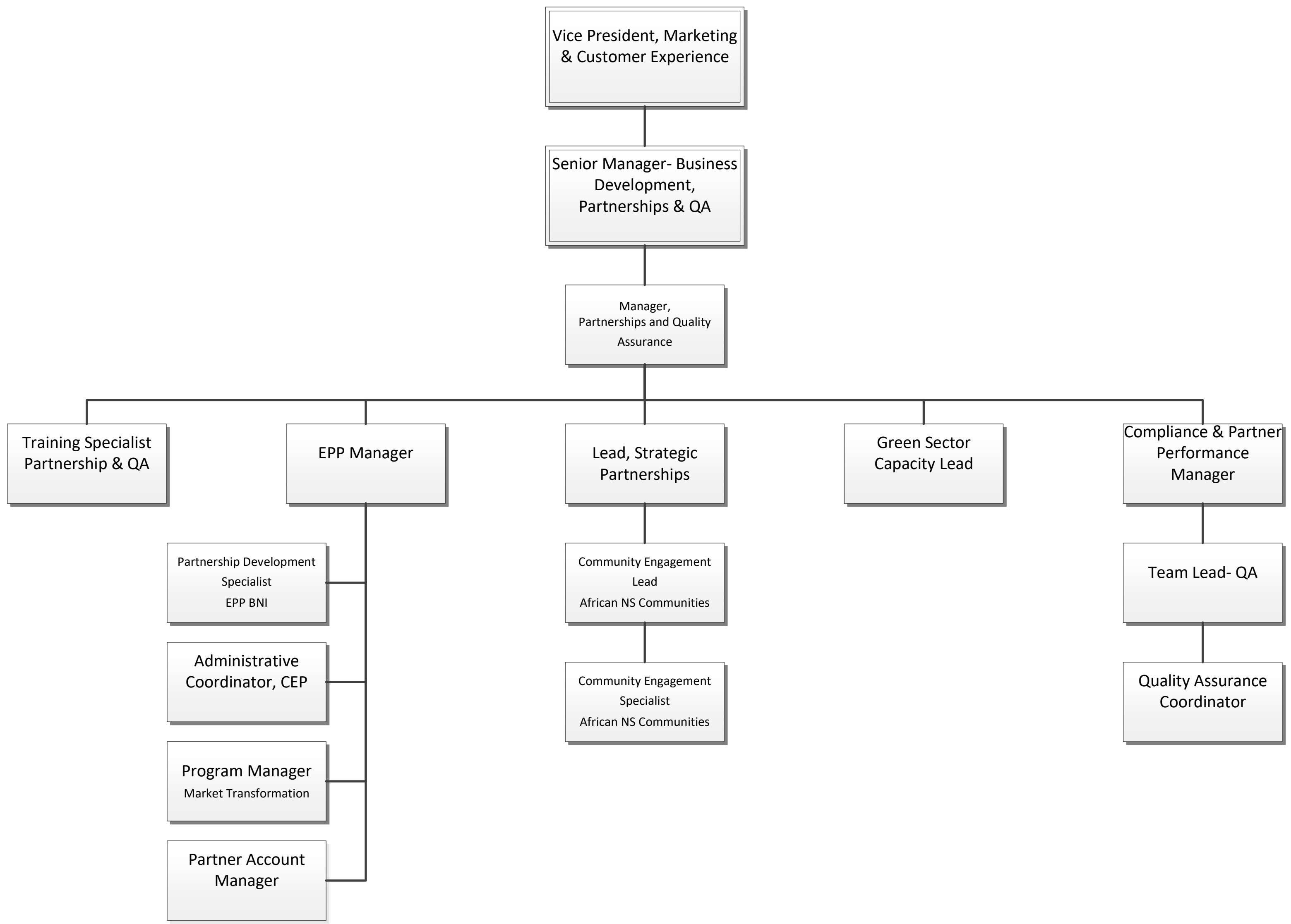
EfficiencyOne
2025
Customer Experience & Partnership



EfficiencyOne
2025
Service Delivery



EfficiencyOne
2025
Partnerships and Quality Assurance



Request IR-06:

Regarding E1's annual expenditures:

(a) What dollar amount was spent on salaries and benefits during each of the past 5 years?

(b) Did any employees receive bonuses? If so, are bonuses available to all employees?

(c) How many employees received bonuses in each year?

(d) What was the dollar value of bonuses paid each year?

(e) What criteria are used to determine and award bonuses? If such a policy is in place, please provide a copy of that document.

Response IR-06:

(a) The table below provides the DSM salaries and benefits for 2020 to 2024.

In thousands of dollars

	2020	2021	2022	2023	2024
DSM Salaries & benefits	$ 6,478	$ 8,076	$ 8,698	$ 9,588	$ 11,147

(b) E1 does not have a bonus program in place for employees. However, in recognition of exceptional effort—such as sustained overtime, performance beyond regular job expectations, or the successful delivery of major initiatives—E1 may, on a discretionary basis, provide employees with various forms of recognition. Examples of this recognition may include additional paid time off, one-time cash payments, gift certificates, attendance at conferences or training programs, team lunches, or participation in team-building events. These recognitions are not structured as a formal or recurring bonus plan and are not universally available to all employees. They are awarded selectively, based on specific circumstances, to acknowledge extraordinary contributions and to support employee well-being and engagement.

(c) Please refer to part (b) of this IR Response.

(d) Please refer to part (b) of this IR Response.

(e) E1 does not have a bonus policy. Discretionary recognition is determined by senior leadership based on specific circumstances, such as extended periods of overtime, delivery of key projects under tight deadlines, or contributions that significantly exceed role expectations. These recognitions are awarded on a case-by-case basis and are not governed by a standardized or written policy.

Request IR-07:

The Board's Decision in Matter M10473 approved the 2023-2025 DSM Plan with specific annual expenditures and performance targets. Amended legislation extended that DSM Plan to include the 2026 calendar year with an expenditure level of $63,750,000 and requires E1 to seek Board approval of its targets for the one-year extension. However, on page 2 of 25 in E1's Evidence, E1 states: "the Board approved 2023-2025 DSM Plan performance targets *must be revised* to establish targets for the extended 2023-2026 term." [*emphasis added*]

(a) Given that a specific expenditure level and specific performance targets are being set for 2026, please explain why the targets for 2026 cannot be treated separately from the targets already established for the 2023-2025 term.

(b) Is there any benefit to ratepayers to combine the 2026 targets with the 2023-2025 targets? Please explain.

(c) If E1 is not successful in achieving its already established 2023-2025 targets and related expenditure levels, does it believe that the shortcomings could merely carry over to 2026? Please explain.

(d) Does E1 believe that the Board is restricted from establishing new or different performance standards or performance targets for 2026 and must only revise the targets previously established for 2023-2025? Please explain.

(e) As a mature public utility with annual ratepayer funding in the range of $60 million, does E1 consider it appropriate for additional performance metrics to be established relative to customer service or other administrative matters? Please explain.

Response IR-07:

(a) The one-year extension in 2026 is not a standalone one-year DSM plan. Rather, the legislation extends the existing 2023-2025 DSM Plan to include the new 2026 year. Specifically, the legislation states as follows: [1]

> Agreement extended
>
> 79J (1) Notwithstanding clause 79I(2)(a), the demand-side management purchase agreement approved by the Board to the end of the 2025 calendar year is extended to include the 2026 calendar year.

The legislation therefore extends the current agreement through 2026, making 2026 part of an extended 2023-2026 DSM Plan. Performance targets under DSM plans are cumulative: that is, the targets are pursued throughout the term of the DSM Plan. Since the legislation extended the current agreement by one additional year, the cumulative performance targets had to be revised to reflect this extended agreement term.

(b) As noted above, the legislation requires that EfficiencyOne (E1) incorporate the 2026 targets into the extended 2023-2026 DSM Plan targets. Multi-year DSM Plans benefit ratepayers by providing predictability in program funding and implementation thus achieving enhanced program reach and impact for customers; provides stability which allows for better coordination and integration of various initiatives leading to more effective and sustained energy savings; allows for development of more comprehensive

[1] Bill 6 - An Act Respecting Agriculture, Energy and Natural Resources Chapter 4 Acts of 2025, s. 20, Part IV Public Utilities Act, Chapter 380 Amendments, Royal Assent, March 26, 2025; and Public Utilities Act, C 380, R.S.N.S 1989, as amended 79J (1).

programming including investment in new multi-year technologies; and reducing administrative and regulatory costs associated with single year approvals. In the case of the 2026 DSM Extension, E1 sought to maximize these benefits to ratepayers by continuing with proven technologies and program design and following a consistent Balanced Plan Approach. E1 believes that such an approach is consistent with the legislative intent of the extension and would also have the benefit of lessening administrative and regulatory timing and costs which ultimately benefit ratepayers.

(c) As noted above, the performance targets under DSM plans are cumulative. E1 seeks to achieve the performance targets during the term of the DSM Plan. It is important for DSM plan targets to be ascribed to the term as a whole, and not limited to any one year within the term. Program characteristics (e.g., long cycle times), market characteristics (e.g., supply chain issues for specific products), and other external factors (e.g., natural disasters) can impact program and portfolio performance in a given year, and proper DSM planning requires flexibility within a DSM term to account for these differing characteristics in order to achieve performance targets.

(d) The Application before the Board is to extend the current DSM Plan by one additional year. This Application is brought pursuant to the direction under the legislative amendment that requires E1 to seek Board approval of the performance targets for the additional 2026 Plan year. In this Application, E1 is seeking the Board's approval of the applied-for performance targets. It is within the discretion of the Board to approve, deny, or vary the performance target. Consistent with the legislative intent, the 2023–2025 DSM Plan is extended to include 2026. It is not a stand-alone plan year. Therefore, E1 believes it is appropriate that performance targets for 2026 be established by the Board and thereafter are appropriately considered as one year of total cumulative performance targets for the entirety of the 2023–2026 DSM Plan period.

(e) E1 welcomes discussion among stakeholders about what performance target categories should be in place in relation to each new DSM plan that is applied for. This Application, however, is brought pursuant to the legislated extension of the existing DSM plan. The existing performance target categories under that Board-approved plan remain in place. The legislative amendment requires E1 to submit for Board approval its performance targets under each of the categories that were approved for the 2023-2025 DSM Plan. It does not allow E1 to reconsider the performance target categories that were rigorously tested by stakeholders and approved by the Board as part of the application process for the 2023-2025 DSM Plan.

Request IR-08:

Page 14 of 25 of E1's Evidence states:

> **The modelling therefore focuses on accounting for the 2023 and 2024 actual results under the 2023-2025 DSM Plan, as well as the 2025 forecast, to ensure the 2026 DSM Extension targets are informed by what has taken place in 2023 and 2024, and what is forecasted for 2025.**

Table 1 on page 4 of 51 in Appendix A shows that first-year energy savings (GWh) and peak demand savings (MW) targets were both exceeded in 2023 and in 2024, while cumulative expenditures for those two years were 64% of the approved 3-year funding, and the cumulative results for energy and peak demand performance targets were 74% of the corresponding 3-year savings targets.

Please explain in detail how the proposed performance targets for 2026 were determined.

Response IR-08:

EfficiencyOne's (E1) proposed performance targets for the 2026 DSM Extension were determined as an output from Guidehouse's ProCESS™ model for energy efficiency and the DRSim™ model for demand response which was used for the 2023-2025 DSM Plan. For each program, E1 updated savings and costs assumptions to align with changes that had occurred during the three-year implementation period of 2023-2025, informed by program delivery experience, internal performance tracking, independent evaluations, and evolving external factors such as market conditions, technology development, and updates to codes and standards. Since the level of investment had been prescribed in legislation, the model was constrained by the budget. E1 applied design principles that remained consistent with the Board approved 2023-2025 DSM Plan. Design principles are developed to ensure E1 is responsive to the Standardized Filing Framework including a Balanced Plan approach in the Plan development. These include an investment allocation between Residential and Business, Non-Profit and Institutional (BNI) sectors, an energy savings allocation between Residential and BNI sectors and a percentage range of investment for low income and equity customers.

Request IR-09:

On page 13 of 25 of E1's Evidence, in the section titled Economic Uncertainty, E1 stated:

> **While the exact impacts of these trade policies cannot be fully assessed at this time, any economic hardship for Nova Scotians and Nova Scotian businesses (or perceived threat of same) has the potential to materially impact participation in E1 programs. This would have a corresponding impact on both 2025 and 2026 results.**
>
> **…there has been no specific adjustment made in the 2026 target development at this time.**

Is E1 suggesting that its 2025 or 2026 targets may not be achieved despite its 2023 and 2024 targets being over-achieved? Please explain.

Response IR-09:

No, EfficiencyOne (E1) is not suggesting, at this time, that the 2025 and 2026 targets will not be achieved as a result of this potential risk factor. However, E1 has identified the recent economic uncertainty as a potential material risk to its operations that E1 will continue to monitor and assess and will advise the Energy Board if there is any anticipated future impact on performance.

Request IR-10:

With regards to Table 1 on Page 3 of 25 of E1's Evidence:

(a) Under "Energy and Demand Savings", please identify the "% of Energy Non-Lighting Savings" for 2026 and 2023-2026.

(b) Under "Energy and Demand Savings", please identify "DR as % of NS Power Peak Load" for 2026 and 2023-2026.

(c) Under "Demand Response (DR) Investment", please identify the "10 Year Levelized Cost ($/kW-yr)" for 2026 and 2023-2026.

Response IR-10:

(a)

Insights	2023-2025 Plan as Approved	2026 DSM Extension	2023-2026
Energy & Demand Savings			
% of Non-Lighting Energy Savings	69%	73%	70%
DR as a % of NS Power Peak Load	1%	1%	1%
Demand Response (DR) Investment			
10 Year Levelized Cost ($/kW-yr)[a]	230	461	N/A

[a] A 2023-2026 10-year levelized cost that combines the results from the 2023-2025 and 2026 Plans is not considered applicable because both analyses included overlapping 10-year periods. The 2026 levelized cost is an updated version of the 2023-2025 analysis that reflects the most accurate assumptions.

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

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

Request IR-11:

Please provide the Statistics Canada data and related calculations referenced in the footnote on page 5 of 25 of E1's Evidence.

Response IR-11:

The Statistics Canada 2021 Census of Population for Nova Scotia reference is found at this website link: Profile table, Census Profile, 2021 Census of Population - Nova Scotia [Province]. This link to the Statistics Canada data can be found on page 10 of Appendix A, in footnote 16 of EfficiencyOne's (E1) Application.

The data indicating a 14.9% prevalence of low income based on the low-income measure, after tax (LIM-AT) (%), can be found on this Statistics Canada webpage and Profile table under the subheading "Low income and income inequality in 2020" and specifically within the eleventh row under this subheading.

As noted in Appendix A (page 9-10), the updated Statistics Canada 2021 low-income prevalence factor of 14.9% was used to inform, and subsequently modify, E1's design objective applied to the 2026 DSM Extension as related to the % investment in low-income and equity of total energy efficiency portfolio investment. The design objective applied to the 2026 DSM Extension was 15% to 20%.

The design objective in the 2023-2025 Plan had used 2016 Census profile data of a 17.2% low-income prevalence factor (the most recent information available at that time), to inform its plan design objectives of 17% to 22% of total energy efficiency portfolio investment.

Request IR-12:

Please provide a version of Table 2 on page 6 of 25 of E1's Evidence to show

(a) expected 2025 DSM rate class expenditures from the 2023-2025 DSM plan,

(b) expected 2024 DSM rate class expenditures from the 2023-2025 DSM plan, and

(c) final 2024 DSM rate class expenditures.

Response IR-12:

(a) Table 1, below, provides the requested version of Table 2 from page 6 of EfficiencyOne's (E1) Evidence in the E1 2026 DSM Extension Application. Please note that 2023 Plan and Actuals have been included for comparison across the approved 2023-2025 DSM Plan.

Table 1: E1 Rate Class expenditures (2023 Plan and Actual, 2024 Plan and Actual, 2025 Plan, 2026 Extension)

Rate Class	2023 Plan ($ million)	2023 Actual ($ million)	2024 Plan ($ million)	2024 Actual ($ million)	2025 Plan ($ million)	2026 Extension ($ million)
Residential/Charitable (2,3,4)	28.2	24.1	31.7	37.5	34.5	33.9
Small General (10)	2.7	2.7	2.8	3.8	3.0	3.1
General Demand (11)	13.8	10.2	14.3	17.4	15.4	17.0
Large General (12)	2.4	1.1	2.4	0.8	3.1	1.6
Small Industrial (21)	1.8	0.7	1.8	1.3	1.9	1.4
Medium Industrial (22)	1.0	2.0	1.1	1.9	1.1	2.4
Large Industrial (23,25)	2.2	4.1	2.3	2.3	2.4	3.9
Municipal (24)	1.0	0.5	1.0	0.8	1.1	0.5
Unmetered (999)	0.0	0.0	0.0	0.0	0.0	0.0
Total	53.1	45.3	57.5	65.7	62.5	63.75

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

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

Request IR-13:

Page 45 of 51 of Appendix A of the Application states: "Investment for Development and Research has increased in 2026 compared to 2023-2025 to support the continuation of E1's heat pump water heater market transformation pilot, launched in 2024." Further, Table 22 of Appendix A shows a planned investment of $2.4 million in 2026 associated with Development and Research. The 2023-2025 DSM plan includes $1.5 million in each of 2023, 2024 and 2025 for Development and Research.

Please explain specifically why an additional spend of $0.9M is required in 2026 for the "heat pump water heater market transformation pilot".

Response IR-13:

The estimated $0.9 million in additional funding for 2026 is not solely allocated to the Market Transformation Heat Pump Water Heater (HPWH) Pilot but also to a broader set of Development and Research (D&R) activities. These activities are aligned with the approved 2023–2025 Demand-Side Management (DSM) Plan, including demand response pilots and emerging technology research.

E1 has concluded work with Resource Innovations, E1's expert consultant on market transformation and its third-party evaluator to develop a market transformation framework, design the HPWH pilot, and establish a methodology for evaluating associated energy savings. Since 2024, the pilot transitioned to the implementation phase, requiring increased resource allocation. Activities planned for 2025 and 2026 include engagement with manufacturers, distributors, and retailers to raise awareness of the pilot; public- and industry-facing outreach; development of digital resources; and virtual and in-person training for stakeholders such as

Energy Advisors, plumbers, and HVAC professionals. These initiatives align with the market transformation framework and evaluation plan. As the program scales, this investment will serve to broaden its reach, facilitate market transformation, and support the long-term success and impact of the pilot.

Request IR-14:

Page 15 of 25 of E1's Evidence states: "E1 notes that while the August 2024 avoided costs provided by NS Power have been used for purposes of 2026 Extension benefits calculations, further work remains to be done in this area."

Please elaborate on the further work that remains to be done. e.g.,

- **What are the current deficiencies?**
- **Who will be doing that work?**
- **When is it anticipated to be done?**

Response IR-14:

EfficiencyOne's (E1) comments on the August 2024 avoided costs submitted to NS Power on April 7, 2025 have been provided in Attachment 1 to this IR response. E1 understands that updates to these avoided costs as a result of E1's comments would be conducted by NS Power. E1 has not received a timeline from NS Power on when they will be able to respond to E1's comments.

1. BACKGROUND

In 2024, NS Power led the development of electric utility avoided costs using the 2022 Evergreen Integrated Resource Plan (IRP) Update. While E1 has used the avoided costs resulting from this development work as provided on August 23, 2024 by NS Power, E1 continues to note several unresolved items that remain. E1 believes it is important to work through these items in time to incorporate updated avoided costs (should they result from resolving the remaining issues) in 2027-2031 DSM Plan.

2. CE1-E1-R2 SCENARIO RE-RUN

As part of the calculation of DSM avoided costs, NS Power ran the No DSM and No DR scenarios at a lower resolution than the 2022 Evergreen IRP scenarios. As part of the August 23, 2024 avoided cost update letter NS Power clarified that, "In order to make an apples-to-apples comparison between scenarios, the expansion plan for the Evergreen IRP scenario CE1-E1-R2 case was rerun using the same level of resolution as the No DSM and No DR scenarios. All other assumptions were kept the same. The resulting expansion plan (labelled as 'Base DSM' to differentiate it from the original scenario from the Evergreen IRP) had different timing for resource retirements and additions when compared to CE1-E1-R2 and the additional retirement of Tuft's Cove 1 and 2 (which was seen in other IRP scenarios)."[1] Since it is the new 'rerun' scenario that is being used to develop avoided costs E1 questions whether the differences noted in the expansion plan have a material effect.

These scenarios can be summarized as follows:

- **CE1-E1-R2**: preferred scenario from the 2022 Evergreen IRP, which includes the "base" level of DSM from E1's potential study work. This scenario is not used in the avoided cost calculations.
- **No DSM:** scenario based on CE1-E1-R2, but with all DSM removed. Lower modelling resolution was applied for this scenario compared to the original CE1-E1-R2 scenario. The No DSM scenario is sometimes referred to as the "No EE, No DR" scenario.
- **No DR**: scenario based on CE1-E1-R2 but with demand response removed (energy efficiency remains). Lower modelling resolution was applied for this scenario compared to the original CE1-E1-R2 scenario.
- **Base DSM**: scenario based on CE1-E1-R2, including the same level of DSM. Lower modelling resolution was applied for this scenario compared to the original CE1-E1-R2 scenario.

[1] NS Power. "2024-08 DSMAG Avoided Cost Update" letter to DSMAG.

In Table 1 below, E1 compared the resource build out between CE1-E1-R2 and Base DSM in 2035 and 2050. As described by NS Power, we would expect both scenarios to have very similar resource build outs, as the only difference is the temporal resolution at which they were modelled.

Table 1: Comparison of the CE1-E1-R2 scenario and Base DSM scenario resource build out in 2035 and 2050. Differences in resource build-out between scenarios have been highlighted.

Resources	New Generation by 2035 (MW)			New Generation by 2050 (MW)		
	CE1-E1-R2	Base DSM	Difference	CE1-E1-R2	Base DSM	Difference
Existing Coal Retirements	0	0	0	0	0	0
Existing Gas Retirements	0	0	0	0	0	0
Gas - New CTs & Recips	770	900	-130	1670	2250	-580
Gas - Conversion	150	150	0	0	0	0
Diesel CTs	231	231	0	231	231	0
Domestic Hydro	374	374	0	374	374	0
Tidal	9	9	0	9	9	0
Biomass	75	75	0	75	75	0
Wind	2994	2978	16	3291	3573	-282
Solar	203	202	1	1002	202	800
Maritime Link Blocks	153	153	0	153	153	0
Synchronous Condensers	200	200	0	200	200	0
Firm Imports	0	0	0	0	0	0
Nuclear	0	0	0	450	0	450
HFO - Conversion	459	459	0	0	0	0
Hydrogen	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0
Battery 4H	200	200	0	400	240	160
Total	**5818**	**5931**	**-113**	**7855**	**7308**	**547**

In 2035, the CE1-E1-R2 and Base DSM scenarios are reasonably similar; the main difference being 130 MW of additional new Gas CTs in the Base DSM scenario. In 2050, the differences between the scenarios appear significant. The Base DSM scenario builds out an additional 580 MW of gas and 282 MW of wind; while CE1-E1-R2 builds out 800 MW more of solar, 450 MW of nuclear, and 160 MW of batteries. It is notable that the Base DSM scenario appears to build more cheap resources (gas, wind); while the CE1-E1-R2 resource builds more expensive resources (solar, nuclear, batteries).

E1 does not have enough information to draw firm conclusions about the basis for, or implications of these differences on avoided costs; however, we expect there could be material impacts on the avoided costs. These results warrant a more comprehensive explanation from NS Power.

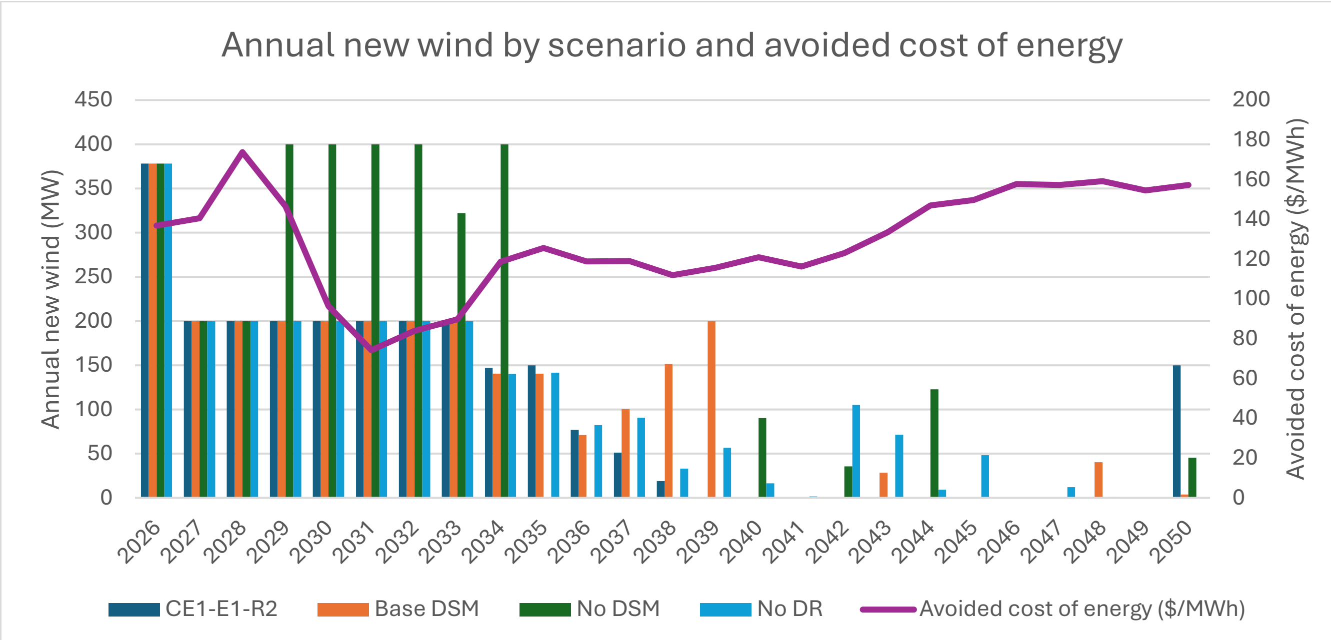
A. Why did the avoided cost scenarios have to be run with a lower level of resolution rather than at the same resolution as the original IRP scenarios?

B. The observations regarding differences between the original and re-run scenarios appear to indicate that assumptions differ between the two. Please describe all assumption differences between the original scenarios and re-run scenarios (e.g., constraints etc.).
C. Given the summary evidence presented above, what documentation can NS Power provide demonstrating the avoided costs results using the lower resolution Base DSM scenario would not be materially different when compared to a higher resolution scenario run?
D. What is leading to the Base DSM scenario selecting different resources in the latter years of the study period compared to CE1-E1-R2?
E. Please provide revenue requirement results for both the CE1-E1-R2 scenario and Base DSM scenarios.
F. The current comparisons result in the base DSM scenario having higher emissions (due to greater fossil and less wind generation) than the No EE No DR scenario in 2031-2033. Please comment on steps NS Power has taken, or can undertake to investigate how the analysis and plans can be modified so that the Base DSM scenario (with lower total MWh demands) results in lower emissions than the without EE/DR scenario?

3. ANNUAL NEW WIND MODELLING CONSTRAINT

E1 reviewed the annual amount of new wind resources built in each year by scenario, as shown in Figure 1. Apart from planned wind projects expected to be online by 2026, E1 understands an annual new wind cap of 200 MW/yr was applied in the model. This is observed in scenarios CE1-E1-R2, Base DSM, and No DR. Unlike the other scenarios, the No DSM scenario builds wind at a rate of 400 MW/yr regularly through 2035.

Figure 1: Annual new wind build rates of CE1-E1-R2, Base DSM, No DSM, and No DR scenarios. Annual avoided cost of energy results included in purple.



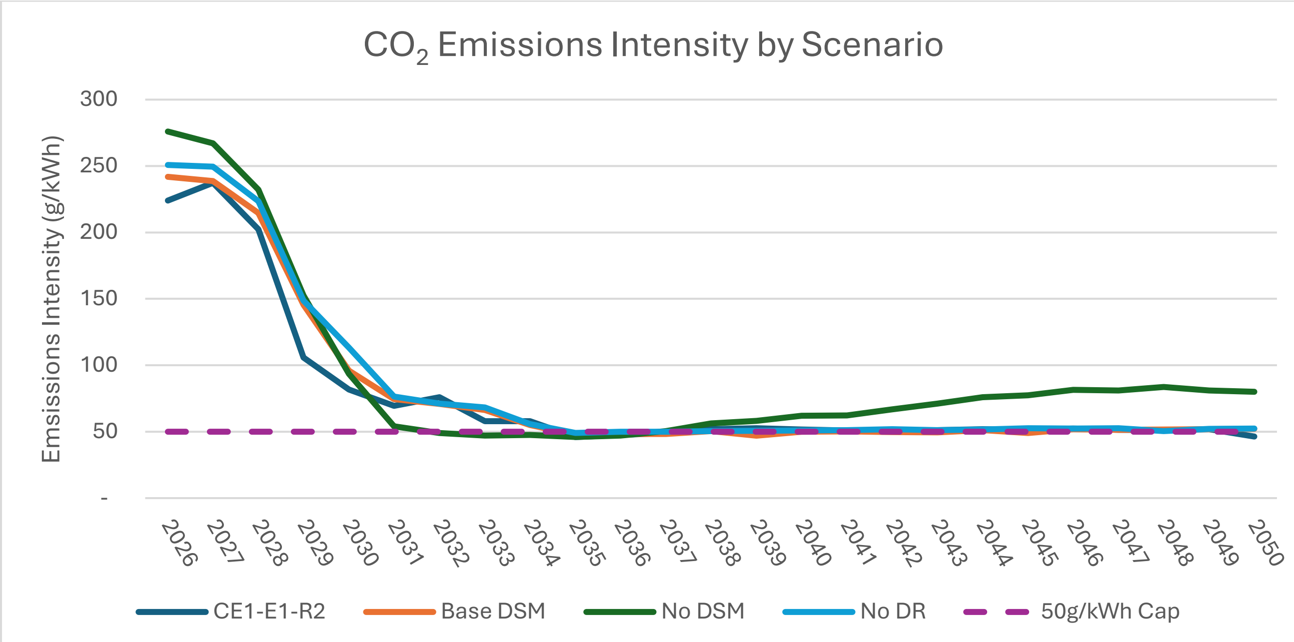
Allowing the No DSM scenario to have greater access to new wind (a relatively cheap resource) compared to the DSM scenarios is expected to have impacted the avoided costs results. This is understood to be the likely cause of the dip in avoided costs seen in 2029-2035 in Figure 1.

For the avoided costs to be meaningful, E1 understands that the same constraints must be applied in the with DSM and no DSM scenarios. Therefore, if it was determined that the new wind constraint had to be relaxed for the No DSM scenario, it must also be relaxed in all other scenarios.

4. GHG EMISSIONS BY SCENARIO

NS Power's August 23, 2024 avoided costs deliverable provided annual GHG emissions for the scenarios CE1-E1-R2, Base DSM, No DSM ("No EE, No DR"), and No DR. E1 has plotted the annual CO_2 emissions intensity by scenario in Figure 2.

Figure 2: Annual CO_2 emissions intensity of NS Power's four modelled IRP scenarios from August 23, 2024.



The 2022 IRP assumptions state, "NS Power will assume that a Net Zero 2035 or Net Zero 2050 (NZ35/NZ50) electricity system will have maximum annual GHG emissions of 50g/kWh from the electricity sector. This intensity limit will be modelled as a series of annual carbon caps derived from the input load to each scenario."[2] For the scenarios included in the avoided cost analysis, this would mean the 50g/kWh would begin in 2035 and apply for the remainder of the study period. The scenarios CE1-E1-R2, Base DSM, and No DR appear to adhere to this constraint. The No DSM scenario does not appear to adhere to the 50g/kWh post-2035 constraint. As can be seen in Figure 2, the No DSM scenarios briefly achieves 50g/kWh emissions intensity, and then rises steadily until it is greater than 80g/kWh in the last five years of the study period.

In line with E1's concerns regarding the new wind modelling constraint, E1 observes that for the avoided costs to be meaningful, the same constraints must be applied in the With DSM and No DSM scenarios.

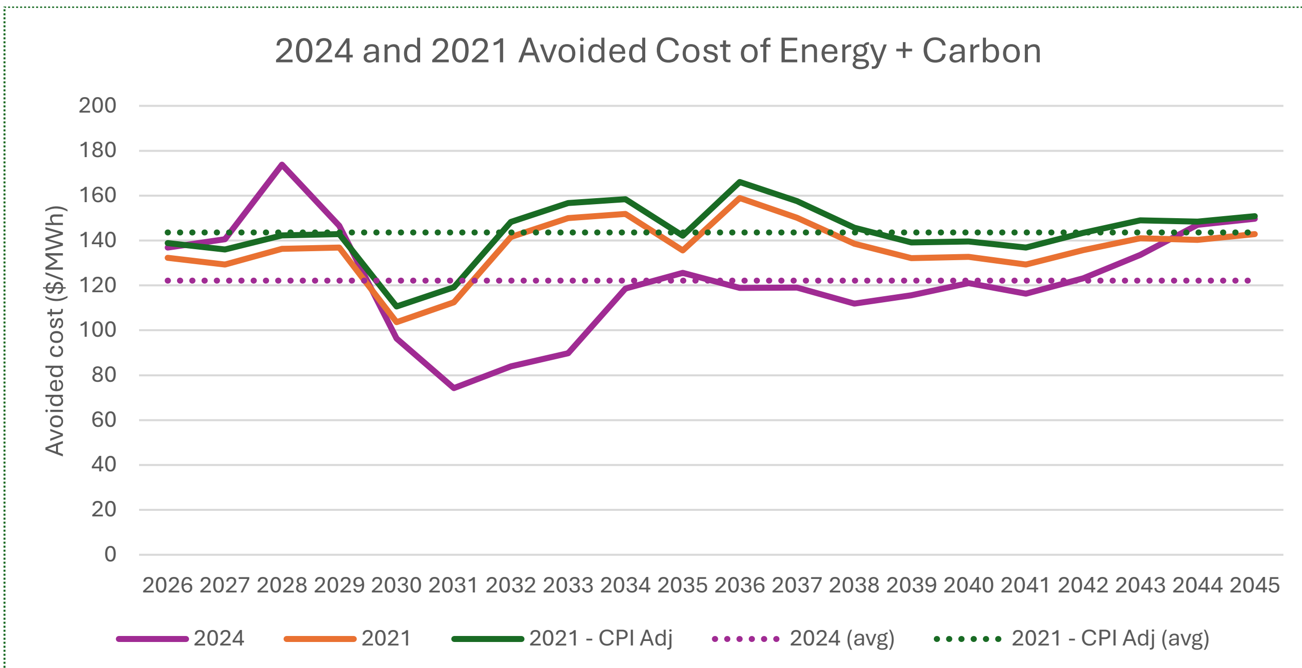
G. Please explain why the 50g/kWh post-2035 emissions constraint has not been applied to the No DSM (No EE, No DR) scenario.

5. COMPARISON OF 2021 TO 2024 AVOIDED COSTS

[2] 2022 Evergreen IRP Updated Assumptions – Revised January 2023. Slide 12. January 26, 2023.

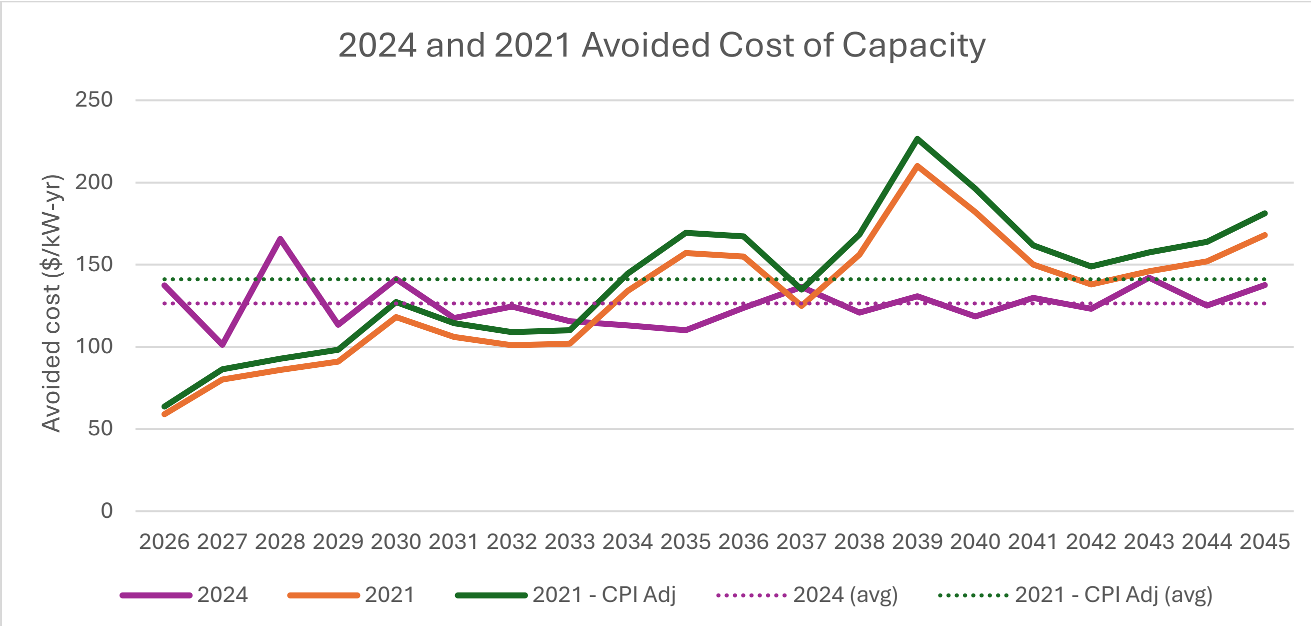
E1 assessed the differences in avoided costs between the previous 2021 avoided costs (developed from the 2020 IRP) and August 2024 avoided costs. The results are presented in Figures 3 and 4, with a subsequent discussion of the results. These figures include the 2026-2045 period where data is available from both analyses that is applicable to the 2026 extension and 2027-2031 DSM Plan. E1 has focused on annual rather than levelized values because annual avoided costs are used in DSM Plan modelling[3], and annual values provide additional insights such as trends over time. The 2021 and 2024 avoided costs of energy developed by NS Power differ in that the 2021 do not include an embedded cost of carbon while 2024 avoided cost of energy do (per NS Power's description). Because the 2024 avoided costs of energy have not been provided with and without the embedded cost of carbon, the only way to compare trends over time is to add the 2021 avoided cost of energy and carbon together.

Figure 3: Comparison of NS Power's 2024 avoided cost of energy (purple) to NS Power's 2021 avoided cost of energy plus the avoided cost of carbon. Orange line is unadjusted energy and carbon. The green line includes a CPI adjustment for energy only.



[3] As recommended by EFG in its BCA report.

Figure 4: Comparison of NS Power's 2024 avoided cost of capacity (purple) to NS Power's 2021 avoided cost of capacity. The orange line is 2021 unadjusted; the green line includes a CPI adjustment.



Discussion of 2021 and 2024 avoided cost results:

Energy and carbon combined *(*Figure 3*)*:

- When assessing the 2026-2045 period, average avoided costs have **decreased 11%** compared to 2021 and **decreased 15%** compared to the 2021 CPI adjusted avoided cost.
- Temporal trends: Annual avoided costs of energy in 2021 remained relatively constant, slowly rising from $83/MWh in 2026 to $102/MWh in 2045. In the 2024 analysis, there is more fluctuation in energy avoided costs, with a peak of $174/MWh in 2028 followed by a dip to $74/MWh in 2031, and a slow rise back to $150/MWh by 2045.
- Embedded avoided cost of carbon (also addressed in item #5 below): Please provide NS Power's estimate of the embedded avoided cost of carbon on an annual basis. How much of the avoided cost value for each year in Figure 3 is associated with avoided cost of energy, and how much is the embedded avoided cost of carbon. Please explain the details of your calculations.

Capacity (Figure 4):

- When assessing the 2026-2045 period, average avoided costs have **decreased by 3%** compared to 2021, and **decreased by 10%** compared to the 2021 CPI adjusted stream.
- The levelized avoided costs from 2021 (pre-PRM) were $120/kW-yr compared to $128/kW-yr for 2024, representing a 7% increase. (Note, avoided costs were levelized over different periods in the

2021 and 2024 analyses). Levelized costs increase while average annual didn't because the 2021 avoided costs were higher in the latter part of the study period.

- Temporal trends: Annual avoided costs of capacity in 2021, showed an increasing trend with avoided costs starting in 2026 at $59/kW-yr and rising to $168/kW-yr by 2045, with a brief peak of $210/kW in 2039. In comparison, in the 2024 analysis avoided costs of capacity remain fairly flat throughout the study period, ranging from a low of $101/kW-yr to a high of $166/kW-yr.

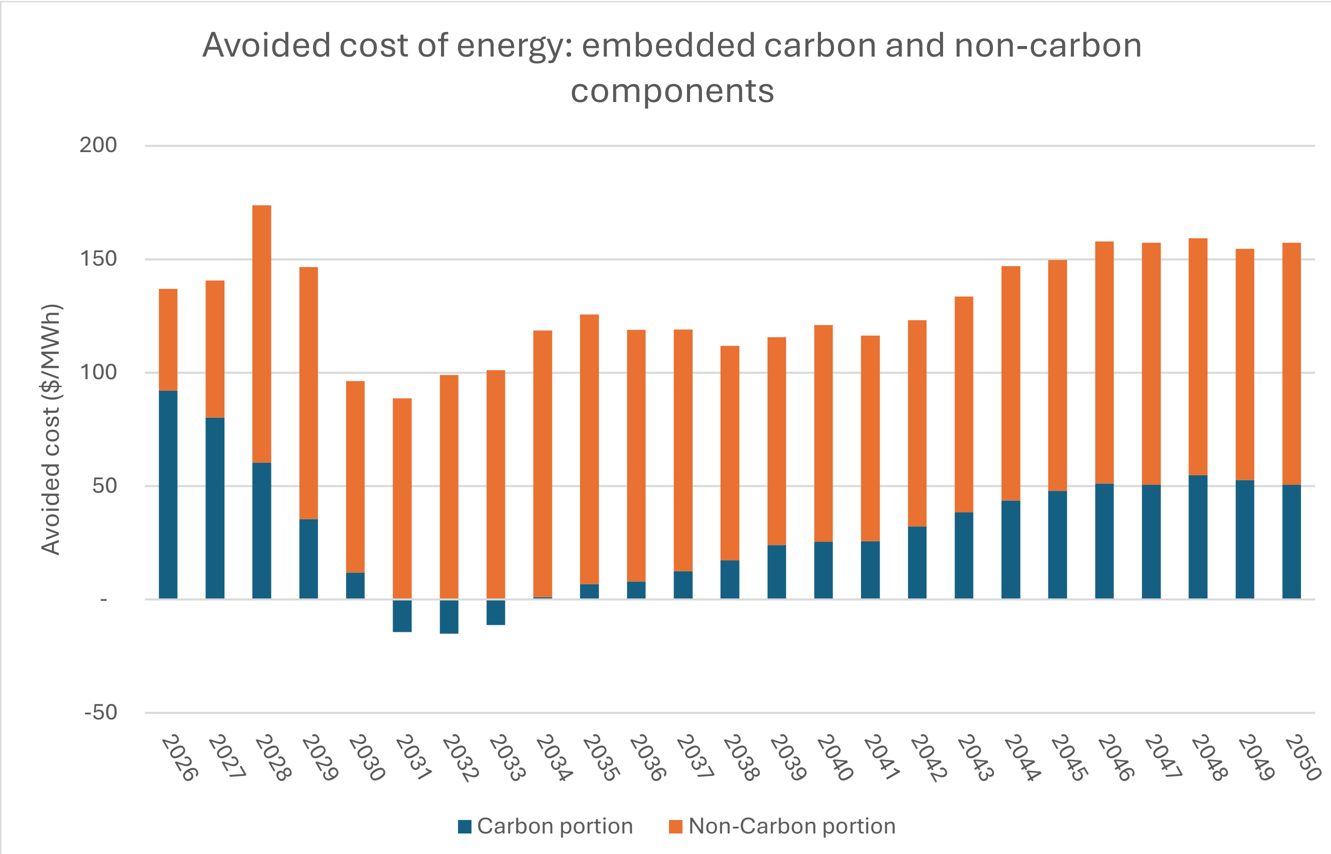
6. EMBEDDED AVOIDED COST OF CARBON WITHIN AVOIDED COST OF ENERGY

At the direction of the Nova Scotia Utility and Review Board (NSUARB), in 2024 E1 initiated a process led by Energy Futures Group (EFG) to assess and develop an optimal DSM cost-effectiveness testing methodology. E1 expects to file a Benefit-Cost Analysis Application in May 2025. If approved the new BCA test would be used for E1's 2027-2031 DSM Plan.

The recommended Nova Scotia benefit cost analysis test includes the societal impacts of greenhouse gas emissions. To avoid double counting greenhouse gas emissions impacts, EFG recommends the *net* emissions of carbon dioxide equivalent (CO2e) greenhouse gases be calculated for all efficiency and fuel switching measures. This means that any costs of carbon compliance/pricing embedded within electricity costs must first be subtracted from the societal cost of carbon before being applied to any GHG savings of the DSM scenario compared to the No DSM scenario.

E1 understands that carbon pricing impacts are incorporated within the avoided cost of energy, as part of the 2022 Evergreen IRP. This is a reasonable approach; however, an estimate of the cost of carbon embedded within avoided cost of energy will be required to accurately estimate the net societal impacts of greenhouse gas emissions under the draft BCA framework. In its June 11, 2024 avoided cost response, NS Power stated that "in general, the OBPS carbon tax would be reflective of the marginal cost of carbon". E1 has used the OBPS carbon tax and applied it to the difference in carbon emissions between the with DSM and No DSM scenarios to estimate the embedded price of carbon, which is a component of the avoided cost of energy. This is presented in Figure 5.

Figure 5: Annual avoided cost of energy values broken out by the estimated carbon portion based on the OBPS carbon tax, and the remainder (non-carbon portion).



Observations:

- In 2026, the embedded avoided cost of carbon represents 67% of the total avoided cost of energy, leaving 33% ($45/MWh) for the non-carbon avoided cost of energy component. The percentage steadily declines until we see negative avoided costs of carbon in 2031-2033 (representing higher carbon emissions in the DSM scenario than the No DSM scenario). In the latter years of the study, the percentage embedded avoided cost of carbon rises back up to the 30-34% range.

Discussion:

- Some of the observations noted above may in part be driven by inconsistent scenario constraints, as discussed elsewhere in this document. If, as recommended above, new wind build out and GHG emissions constraints are applied consistently across all scenarios, NS Power should also reassess and provide adjusted estimates for the embedded cost of carbon as a portion of the overall avoided cost of energy.

- Any changes to the embedded cost of carbon will have a direct impact on the net societal impact of carbon, applied within the recommended Nova Scotia test.

H. E1 requests that NS Power provide additional context for the results found in Figure 5. E1 requests that in future avoided cost of energy results, NS Power includes an estimated breakdown of carbon compliance and non-carbon related.

7. MARGINAL LINE LOSSES

As part of E1's BCA work completed with EFG in 2024 it was identified that for the purposes of cost-effectiveness testing it is appropriate to use marginal rather than average line losses. The concept of marginal line losses is important because line losses grow exponentially with higher levels of load and therefore an incremental kW/kWh addition or reduction can have different line losses than the average system line losses. Throughout the Evergreen IRP avoided cost process, E1, EFG, and Synapse have advocated for consideration of marginal rather than average line losses, as established best practice in benefit cost analyses.

> In its July 22, 2024 comments, Synapse stated, "For clarity, Synapse is focused on the application of marginal line loss factors to avoided generation, capacity, and distribution costs and is not focused on avoided energy costs. We acknowledge and accept NS Power's concerns about aggregating marginal line losses over a long time series as it related to avoided energy costs."
>
> In response, NS Power has said, "NS Power continues to have concerns in how to calculate marginal line losses and their application in time series analysis. NS Power would like to propose this topic be explored deeper in future updates. NS Power is in the process of completing a line loss study which will provide it with a greater understanding of losses by rate class and losses during peak. The outputs from this study would form a starting point to inform conversations on marginal losses in the future".[4]
>
> Synapse also asked, "In what way does the peak winter MW load forecast account for the fundamentals-based exponential increase in line losses when end-user peak load is higher than the reference case peak load?"
>
> NS Power responded, (August 23, page 8 of 11): "The loss percentage applied to peak losses is the same in all scenarios. As NS Power indicated in its response to stakeholder comments on May 13, 2024 it is concerned with aggregating marginal line losses across a time series."

E1 and their consultants EFG and Power Advisory support the following:

[4] NS Power Avoided Costs Comments. August 23, 2024. Page 3 of 11.

- The average or long run line losses are appropriate for avoided costs of energy, but for peak (avoided costs of capacity, transmission, and distribution), an esitmate of marginal line losses should be applied.
- If a detailed Nova Scotia-specific analysis of marginal line losses is unavailable, an appropriate approximation should be made in the interim.

E1 remains concerned that despite the application of marginal line losses being best practice - endorsed by the National Standard Practice Manual (NSPM), Synapse, EFG, E1, and Power Advisory - NS Power has been reluctant to engage on this issue.

I. Is the new line loss study NS Power is completing examining marginal line losses? If not, what additional information (outside of updated line loss values) will be available that will help progress the discussion of an appropriate marginal line loss methodology?
J. What is the expected completion timeline for NS Power's updated line loss study?

8. TIME-VARYING AVOIDED COST OF ENERGY

As part of the 2024 avoided cost updates, NS Power produced time-differentiated avoided costs of energy. Avoided costs for three periods have been produced by NS Power: winter on-peak, winter off-peak, and non-winter. Table 2, provided by NS Power as part of the August 23, 2024 avoided costs update provides an overview of the time-varying periods used in the June 12 analysis, and updated definitions used in the August 23 analysis.

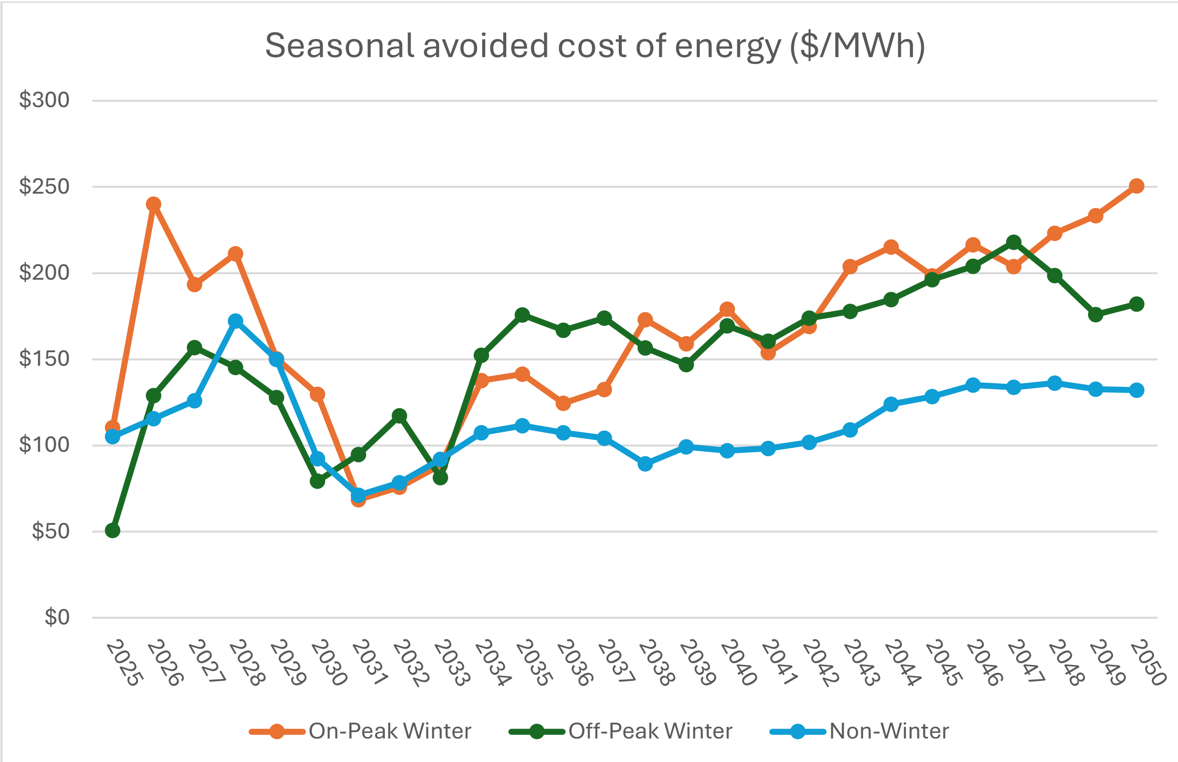
Table 2: NS Power summary of the season definitions for energy used in the June 12, 2024 and August 23, 2024 deliverables.

	Season definitions used in June 12, 2024 analysis	Updated season definitions
Winter On-Peak	Months: Jan, Feb, Mar, Nov, Dec Days of the week: All days Time Periods: 7 am to 11 am, 5 pm to 9 pm	Months: Jan, Feb, Dec Days of the week: Weekdays only Time Periods: 6 am to 10 pm
Winter Off-Peak	Months: Jan, Feb, Mar, Nov, Dec Days of the week: All days Time Periods: 12 pm to 4 pm, 10 pm to 6 am	Months: Jan, Feb, Dec Weekdays: 10 pm to 6 am Weekends: All hours
Non-Winter	Months: Apr, May, Jun, Jul, Aug, Sep, Oct No on-peak/off peak differentiation	Months: Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov No on-peak/off peak differentiation

K. The updated time-varying definitions are saying that 75% of the year (non-winter period) there is no difference between on- and off-peak energy use. Please provide additional rationale for shifting November and March to non-differentiated (non-winter) months.

E1 reviewed the seasonal avoided cost of energy results, as provided by NS Power in the August 23, 2024 deliverable. The avoided costs for the three seasonal periods are plotted in Figure 6.

Figure 6: Seasonal avoided cost of energy results ($/MWh)



Observations:

- There are some years where the on-peak winter avoided cost of energy is lower than the off-peak winter avoided costs (2031, 2032, 2034, 2035, 2036, 2037, 2041, 2042, 2047). The difference is as much as $43/MWh (2036).
- There are some years where the avoided cost of energy for on-peak winter is the same or lower than the non-winter period (2029, 2031, 2032, 2033).

Discussion:

The goal of time-differentiated avoided costs is to better understand and value the marginal impact to the system of removing energy during different time periods (i.e. what is the value of removing a kWh of energy during winter on-peak periods, winter off-peak periods, and non-winter periods?) Time-differentiated avoided costs can also be used to help understand the impacts of other DSM resources such as electrification, solar, and demand response (i.e. what is the impact of adding, removing, or shifting load in different time periods?)

Avoided costs that reflect the varying system avoided costs at different times of the day/month/year can result in more accurate estimates of the system benefits and costs of various DSM resources. This in turn can help inform program design. Some examples of this include:

- If avoided costs are higher during the winter period and lower during the summer period, then a kWh saved during the winter period by a heat pump measure is more valuable than a kWh saved by an air-conditioning measure in the summer. The increased benefits associated with winter kWh savings and reduced benefits associated with summer kWh savings, creates an appropriate economic price signal.
- A demand response measure that shifts load from the winter on-peak period to the winter off-peak period creates benefits by shifting energy from a period of high costs to a period of lower costs based on the differential in avoided costs between those periods .

L. The avoided costs produced by NS Power imply that in some years it will be more valuable to reduce energy in off-peak winter or non-winter periods than during on-peak winter periods. It is unclear if this is a modeling artefact or if NS Power expects this to be an accurate reflection of system costs. Please clarify, and discuss how the avoided cost categories provided are an accurate representation of the system needs and appropriate price signals for the DSM administrator to consider in portfolio and program planning?

In its August 24, 2024 deliverable, NS Power stated, “NS Power is not proposing an on-peak/off-peak time differentiation for the non-winter period as no differentiation in costs was observed in the analysis.

This statement and NS Power’s proposed categorization assigning 9 of 12 months in the calendar year to the non-winter period is problematic in several respects.

Is NS Power stating that there is no analyzable material difference in the resources used to serve load, the costs for the resources used to meet the load, and the load itself across all hours for nine months of the year? It would be hard to attribute such a static and stable result to the actual operations and costs of an electric system. As a simple example, there is certainly some diurnal differentiation in electric loads between day and night periods throughout the year, just as there is daily variation in some resources (most obviously solar).

Instead of reflecting or approximating system costs, NS Power’s position likely implies their analysis assumes no cost differentiation for three-quarters of the year, but this is a gross simplification for system planning and investments in both supply and demand side resources.

At minimum, for the purposes of system planning and DSM cost effectiveness screening, we continue to recommend the use of at least four avoided cost categories including an on and off peak period for non-winter.

9. ADDITIONAL SYSTEM IMPACTS OF DSM

As part of its May 13, 2024 comments E1 requested information on additional system impacts that had either (a) been identified through E1's BCA workshops or (b) been identified as additional use cases for demand response and battery resources.

NS Power did not respond to the first part of the question. System impacts identified through the BCA workshops that are currently not quantified or only partially quantified in Nova Scotia include: credit and collection; and risk, reliability, resilience.

In response to the second part of the question, NS Power pointed to the Smart Grid project for avoided costs of demand response resources. While the Smart Grid project did test relevant use cases, it did not quantify the avoided cost values of these use cases and instead used the existing 2021 DSM avoided costs as a proxy. E1 considers this insufficient because it implies that these additional use cases are already embedded in the existing DSM avoided costs (energy, capacity, transmission and distribution), which is not the case.

M. E1 is requesting quantification of the following additional electric system impacts: credit and collection, risk, reliability, resilience.
N. If the Smart Grid project has quantified benefits *incremental* to the existing DSM avoided costs E1 already uses, please provide a specific reference to those avoided cost streams.
O. E1 is requesting that additional use cases that can provide value to the utility system be characterized (both in terms of monetary value and event characteristics/rules). This will enable E1 to design demand response programs that are suited to those use cases (in terms of items such as incentives, control strategies, event windows, eligible technologies, and program mix), and to maximize grid value and cost-effectiveness.

10.RESPONSE TO SYNAPSE'S COMMENTS FROM JULY 22, 2024

As part of its July 22, 2024 comments, Synapse made the following comment:
"The Smart Grid Nova Scotia pilot involved installation and implementation of utility-controlled, behind-the-meter distributed energy resources (DERs) and DER management system. Before applying any

values from the SGNS report to E1's offerings, E1 should consider the differences in asset control between the SGNS DERs and DERs that E1 would support. Also, E1 should consider whether incentives levels and designs are adequately similar to incentives to SGNS participants to support including avoided costs based on SGNS experience. Further, E1 will need to consider how programs can be delivered cost-effectively, since the SGNS pilot saw costs that were an order of magnitude higher than its benefits, as shown below."[5]

E1 can confirm that avoided costs for additional use cases will only be applied to demand response programs where that use case is applicable and intended to be used by NS Power. These use cases may require additional event hours (longer event windows, greater frequency, and longer events), and may be most applicable to highly flexible demand response programs such as water heater and battery direct load control.

When designing demand response programs E1 considers the appropriate incentive level to compensate and retain customers for the service they are providing. E1 also considers the appropriate control strategies needed and has implemented demand response management software (DRMS) solutions to provide the flexibility, control, and visibility needed.

[5] Synapse Comments Avoided Costs 07-22-2024. July 22, 2024.

Request IR-15:

On page 21 of 25 in E1's Evidence, E1 stated that the unit cost of energy savings will increase over time due to factors such as diminishing returns, increased complexity, and market maturity. Indeed, the 2023-2025 Plan projected a unit cost of $0.39/kWh, whereas the 2026 plan extension projects a unit cost of $0.49/kWh, an increase of more than 25%.
In recognition of ratepayer affordability concerns, what steps has E1 undertaken to control costs and minimize such pronounced increases?

Response IR-15:

EfficiencyOne (E1) recognizes affordability is an important consideration for DSM Plans. First year unit cost is a calculated output of E1's investment and savings for a specific period (i.e., one year or for the total DSM Plan). Several factors typically influence this calculation such as the level of participation in a program or program component; the measure mix within a program; changes to savings arising from E1's independent evaluation; and total costs. However, affordability cannot be assessed solely on first-year unit cost. Consideration should also be given to the following:

1) The 2026 DSM Extension investment represents a 2% increase over the approved 2025 investment which is aligned with current inflation rates.
2) In the 2026 DSM Extension, the average measure life is 11.4 years, meaning that customers will continue to accrue benefits over that time period on their energy bills.
3) The lifetime unit cost for the 2026 DSM Extension is $0.04/kWh comparable to the approved 2023-2025 DSM Plan.
4) Additionally, for energy efficiency the lifetime system benefits, (the costs that NS Power will avoid purchasing fuel, building new capacity, and investments in transmission and distribution) are $135 million - far exceeding the first-year investment of $57.2 million.

E1 is committed to controlling costs on an ongoing basis, while at the same time meeting its performance targets. The organization has implemented the following cost management strategies by:

1. Benchmarking - Ensuring its costs are aligned with other similar industries and organizations and confirms this through market research and market comparisons prepared by third parties;
2. Competitive Procurement - Following rigorous procurement practices to achieve best value by acquiring goods and services through a competitive approach;
3. 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; and
4. Process Improvement - Taking a strategic approach to actively initiate process improvements through modernization efforts to maximize cost efficiencies within the organization.

E1's investment in customer incentives continues to be a significant category of spending as expected in a resource acquisition model. E1 continues to assess incentive levels, in accordance with its Incentive Setting Process which was an outcome of the CLEAResult study[1] 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 assess whether the proposed incentive level is appropriate.

[1] M07544, EfficiencyOne Incentive Setting Methodology Review and Recommendations

Request IR-16:

Regarding the Total Resource Cost (TRC) test, in Table 9 on page 40 of 149 in Appendix A of the 2023-2025 DSM application (M10473), the TRC for Residential EE Programs is presented as 1.4 (including carbon) and the TRC for DR Programs is presented as 1.1 (excluding carbon). Nearly all of the components exceed a TRC of 1.0. However, in Table 5 on page 23 of 25 of E1's Evidence in the current application (M12249), the TRC for Residential EE Programs for 2026 is presented as 0.9, and the TRC for DR Programs for 2026 is presented as 0.7. Furthermore, most of the components of those programs have a TRC of less than 1.0.
Please provide a detailed explanation of the reasons contributing to the TRC deterioration for those two programs and their components.

Response IR-16:

<u>Residential Energy Efficiency Programs</u>

In comparing the 2023-2025 DSM Plan Total Resource Cost (TRC) cost results of Residential energy efficiency to the 2026 DSM Extension TRC results, EfficiencyOne (E1) makes the following observations:

- Residential energy efficiency passes the Program Administrator Cost (PAC) test for both the 2023-2025 DSM Plan and the 2026 DSM Extension. This indicates that it is the host customer costs included in the TRC and excluded in the PAC that cause residential energy efficiency to fall below a TRC of 1.0 in the 2026 DSM Extension.
- Measure characterizations, cost assumptions, measure offerings and the avoided costs were updated for the 2026 DSM Extension modelling. E1 considers the primary drivers of the lower TRC results in the 2026 DSM Extension compared to the 2023-2025 DSM Plan to be updated to measure characterizations and cost assumptions.

- Updates to measure characterizations and cost assumptions for the Affordable Multi-Family Housing and Home Energy Assessment program components in particular have led to a lower TRC result for residential energy efficiency in 2026. This is compounded by the removal of two program components, namely Appliance Retirement and Green Heat, both of which had higher TRC results in the 2023-2025 DSM Plan when compared to Affordable Multi-Family Housing and Home Energy Assessment in the 2026 DSM Extension.
    - Affordable Multi-Family Housing is comprised of a limited number of key measures that have seen reductions in unitary energy savings or increases in incremental costs.
    - Home Energy Assessment whole home measures, since the development of the 2023–2025 DSM plan, have seen a 56% decline in the unitary savings and a 13.5% increase in incremental cost.

<u>Demand Response Programs</u>

In comparing the 2023-2025 DSM Plan Total Resource Cost (TRC) cost results of Demand Response (DR) to the 2026 DSM Extension TRC results, (E1) makes the following observations:

- Methodological changes and global input updates were made in the 2026 modelling, compared to the 2023-2025 results. Specifically:
    - For 2026, the cost effectiveness testing (CET) timespan was adjusted to allow for more flexibility in viewing various implementation years in a consistent manner. In the 2023-2025 Plan cost-effectiveness results included 10-years of DR activity (2022-2031). The 2026 DSM Extension cost-effectiveness results included one-year of activities (2026), with any one-time costs being levelized over ten-years to reflect the expected DR program lifespan.

- Avoided costs were updated for the 2026 DSM Extension to reflect the most up-to-date avoided costs of capacity, transmission, and distribution – as provided by NS Power in August 2024.
- Measure characterizations, cost assumptions, and forecast capacity were updated for the 2026 DSM Extension modelling. E1 considers these to be the primary drivers of the lower TRC results in the 2026 DSM Extension compared to the 2023-2025 DSM Plan. In particular, the lower TRC result in 2026 DSM Extension appears to be primarily driven by Behind the Meter (BTM) Battery Control. The TRC results for both the 2023-2025 DSM Plan and the 2026 DSM Extension with BTM Battery Control removed produces the following results:
  - 2023-2025 DR TRC (w/o batteries): 0.72
  - 2026 DR TRC (w/o batteries): 0.77

- BTM Battery Control changes that have resulted in lower TRC results in 2026 DSM Extension include:
  - A significant decrease in the battery adoption forecast. With a smaller program, fixed costs become a significant factor compared to a large program where fixed costs are spread over greater capacity.
  - A significant increase in variable costs related to Demand Response Management System (DRMS)/communication, based on E1's experience operating the Eco Shift program (which includes batteries).

The 2023-2025 DSM Plan included demand response for the first time, which can result in higher volatility in the modelled results than in more mature programs. Delivering programs in 2023-2025 has provided E1 valuable insights into the actual costs and capacity from demand response in Nova Scotia; this has informed the 2026 DSM Extension modelling and will improve accuracy going-forward.

- DR CET results are expected to increase over time for the following reasons:

- As DR programs scale-up, fixed costs will be spread over more capacity (benefits). Some variable costs will also come down as programs scale-up and contracts are re-negotiated.
- Additional use-cases (avoided costs) are possible with DR and will continue to be explored.
- E1 will continue to explore program improvements that will increase utility benefits and/or decrease costs. This will include working with peers across Canada and North America to gain learnings in best practices (particularly related to winter demand response); monitoring technological developments; and considering Nova Scotia-specific impacts such as electrification.

Request IR-17:

On page 24 of 25 in E1's Evidence, E1 determined that "Several directives from the 2023-2025 DSM Plan Decision relate to, and contemplate, the next complete DSM Plan filing (as opposed to the current Extension application)" and therefore chose not to comply with certain Board directives in the current filing. One of those directives requires E1 to provide specific justification, on an individual basis, for each measure that fails the cost effectiveness test.
As noted in the prior IR, a significant number of components in the residential program failed the TRC test. Considering the large 25% step increase in unit cost per kWh, those components should not simply be accepted without understanding why they should be pursued.
Please provide the justification as directed in the Board's Decision in matter M10473.

Response IR-17:

EfficiencyOne (E1) has included a list of the measures that do not meet the Total Resource Cost (TRC) test cost effectiveness screening and the justification for each of these in Attachment 1 to this IR response, filed electronically. E1 has also provided the Program Administrator Cost (PAC) test results for informational purposes. The PAC test includes only the utility costs (E1's costs) and the utility benefits (NS Power's avoided costs).

E1's dedicated low income and equity programs historically have not met the TRC test. The 2026 DSM Extension TRC test results are consistent with this.

- Affordable Multi-Family Homes – Rationale for inclusion: These energy efficient upgrades support the overall program component which is designed to increase equity and accessibility to residential customer segments who face greater barriers to DSM. Additionally, the PAC Test for these measures exceed 1.0, indicating that the measure provides net benefits to the utility system and ratepayers. Also, energy audits which are required for this program are fully subsidized and because there are no associated energy savings these audits do not pass the TRC test.

- Affordable Single-Family Homes – Rationale for inclusion - These energy efficient upgrades support the overall program component which is designed to increase equity and accessibility to residential customer segments who face greater barriers to DSM. Also, energy audits which are required for this program are fully subsidized and because there are no associated energy savings these audits do not pass the TRC test.

- Mi'kmaw Home Energy Efficiency Project – Rationale for inclusion – energy audits which are required for this program are fully subsidized and because there are no associated energy savings these audits do not pass the TRC test.

Other Residential Programs are designed to provide access to energy efficiency programs by offering different options, so all residential customers have the opportunity to recognize benefits.

- Home Energy Assessment (four measures not including energy audits) – Rationale for inclusion – measures that do not pass the TRC test are justified by one of the following reasons:
    - The measure provides whole home support to residential customers.
    - The PAC Test for this measure exceeds 1.0, indicating that the measure provides net benefits to the utility system and ratepayers.
    - The measure remains in its early stage and has the potential to deliver long-term energy savings and cost reductions as market conditions evolve. This measure supports the adoption of emerging technologies and drives market transformation. Additionally, the PAC Test for this measure exceeds 1.0,

indicating that the measure provides net benefits to the utility system and ratepayers.

  - Energy audit measures have a TRC ratio of 0 due to a lack of direct energy savings. However, these audits drive customer awareness, support informed decision-making, and lead to the adoption of cost-effective measures that may not otherwise be pursued. They also contribute to broader program participation, equity, and data-driven program design and support E1's balanced resource plan approach.

- Instant Savings (13 measures) – Rationale for inclusion – measures that do not pass the TRC test are justified by one of the following reasons:
  - The measure contributes to customer satisfaction, program reach, and specific market needs. The measure benefits overall program delivery and does not materially impact the overall cost effectiveness of this program component, which has a TRC ratio of 1.0. Additionally, the PAC Test for this measure exceeds 1.0, indicating that the measure provides net benefits to the utility system and ratepayers.
  - This measure is an early stage offering with the potential to deliver long-term energy savings and cost reductions as market conditions evolve. New measures support adoption of emerging technologies and drive market transformation. E1 monitors the performance, adoption, and cost trends of new measures over time, and will adjust program design and incentives, as appropriate, during implementation of the 2026 DSM Plan. The measure benefits overall program delivery and does not materially impact the overall cost effectiveness of this program component, which has a TRC ratio of 1.0. Additionally, the PAC Test for this measure exceeds 1.0, indicating that the measure provides net benefits to the utility system and ratepayers.

- Efficient Product Installation (six measures) – Rationale for inclusion – These measures serve as a low-barrier entry point into the Efficient Product Installation program component. It drives participant engagement and often leads to adoption of other energy efficiency measures and drives participation in other E1 program components. The measure benefits overall program delivery and does not materially impact the overall cost effectiveness of this program component, which has a TRC ratio of 2.0.

Business Non-Profit and Institutional (BNI) programs are designed to specifically meet the needs of customer sectors to provide access to energy efficiency programs, so all customers have the opportunity to recognize benefits.

- Small Business Energy Solutions (six measures) – Rationale for inclusion – Justification for measures not passing the TRC test are because small businesses often face several barriers to energy efficiency (e.g., time, technical expertise, limited capital), and TRC does not fully account for these. These measures benefit overall program delivery and do not materially impact the overall cost-effectiveness of this program component, which has a TRC of 1.3. The PAC Test for these measures exceed 1.0, indicating that the measures provide net benefits to the utility system and ratepayers.

- Business Energy Rebates (33 measures) – Rationale for inclusion – This program offers instant and application rebates to several customer classes within the BNI sector. These measures contribute to customer satisfaction, program reach, and specific market needs. These measures benefit overall program delivery and do not materially impact the overall cost effectiveness of this program component, which has a TRC ratio of 3.4. Additionally, the PAC Test for these measures exceed 1.0, indicating that the measure provides net benefits to the utility system and ratepayers.