M12282

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF:	**The *Public Utilities Act*, RSNS 1989, c 380, as amended**
	– and –
IN THE MATTER OF:	**An Application by EfficiencyOne for Approval of a New Benefit-Cost Analysis Test for Evaluating Demand Side Management (DSM) Plans**

INFORMATION REQUESTS

TO:	**EFFICIENCYONE**
FROM:	**EASTWARD ENERGY INC.**
RESPONSES DUE:	**JULY 4, 2025**
COPIES:	**1 ELECTRONIC COPY (PDF SEARCHABLE)**
CONTACT PERSON:	**ALLISON COFFIN**
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Request IR-1

Reference: **Evidence Page 7: A benefit-cost ratio threshold of 1.0 or greater of a DSM Plan must always be satisfied at the portfolio level. While measures that do not meet the ratio threshold can be included, E1 must justify their inclusion on the basis that they are required in order to ensure that the DSM Plan complies with the Balanced Plan Approach.**

(a) Please describe in detail the process by which E1 intends to justify the measures that do not meet the benefit-cost ratio threshold of 1.0 or greater.

(b) Does E1 intend to get prior Board approval of all such measures? If not, explain why not.

(c) Does E1 intend to get input from interested parties with respect to the inclusion and justification for any such measures?

<u>Request IR-2</u>

Reference: **Evidence Page 13: Reference is made to section 79A(b)(iv) of the *Public Utilities Act* which refers to "strategic electrification of energy end uses currently powered by fossil fuels in a manner that reduces overall greenhouse gas emissions and electricity costs".**

(a) Please describe E1s understanding of what is meant by "strategic electrification" in this regard.

(b) Please describe the test E1 plans to use to compare greenhouse gas emissions between electricity production and end uses currently powered by fossil fuels.

(c) Please confirm that E1 did not solicit the input of Eastward Energy in the development of its proposed New Benefit-Cost Analysis Test.

<u>Request IR-3</u>

Reference: **Evidence Pages 18/19: E1 indicates that the identified DSMAG members participated in workshops led by E1s Consultant Energy Futures Group, Inc.**

(a) Please confirm that Eastward Energy is not one of the identified parties.

(b) Considering the potential for strategic electrification of fossil fuel powered energy uses, please advise whether E1 is amenable to having Eastward Energy join the DSMAG and participate in the discussions leading to E1s intended application for the five-year 2027-2031 DSM Plan in early 2026 as referenced at Evidence Page 9. If E1 is not in agreement please indicate why not.

Request IR-4

Reference: **Evidence Pages 35-37, Table 11 and Figure 2.**

(a) Although only shown as an "illustrative example" please confirm that based on 1,000 Heat Pump Replacements in Program Year 2026 replacing Natural Gas yields a negative net benefit of ($17.4 million) and a benefit-cost ratio of only 0.45.

(b) Please confirm that E1 would not propose to implement such a measure as a strategic electrification project. If not confirmed explain in detail.

(c) Please explain in detail the basis for the development of each of the Impact categories Benefits and Costs figures shown under the Heat Pump replacing Natural Gas heading of Table 11.

<u>Request IR-5</u>

Reference: **Appendix 8, page 17: "EFG recommends treating gas impacts through the commodity costs is appropriate due to the relatively small size of the gas system and the anticipated level of "DSM portfolio impacts on the gas system"**

(a) Please describe what is meant by the "anticipated level of DSM portfolio impacts on the gas system"?

<u>Request IR-6</u>

Reference: **Appendix B, Page 54 "The starting prices for heating oil and pipeline gas are based on recent provincial data and include a carbon price components based on $110/metric tonne in 2026".**

(a) Please provide the basis for applying this carbon price to pipeline gas and where it is derived or obtained from.

Request IR-7

Reference: General

(a) How does the benefit-cost test capture the cost of additional pressure on meeting the increased electric utility peak demand caused by any "strategic electrification", such as required electric system infrastructure upgrades.

(b) Has E1 specifically coordinated with the incumbent electric utility's planning department in developing the proposed "strategic electrification" plan?

(c) Please confirm that E1 or EFG have not evaluated the benefit of hybrid peaking or dual fuel opportunities in the Application. If not confirmed, please provide an example of how this was evaluated.

<u>Request IR-8</u>

Reference: Appendix B, Table 5

(a) Please explain what is meant by "Social cost of carbon & electric and avoided fuel" under the "Basis for Estimation" column in the Greenhouse Gas Impacts Category row.

(b) For the "direct measure costs" impact, the "Basis for Estimation" column includes the description "Host customer measure costs net of incentives". Please explain what should be considered in the calculation of "Host customer measure cost" with respect to:

i. Measure equipment cost, including whether the full cost of the measure equipment should be considered, or the incremental cost of the measure compared to a baseline or alternative equipment

ii. Measure installation cost

iii. Measure operating and maintenance costs

iv. Any other host customer measure costs

(c) For the direct measure costs impact, does $4.8M represent the full, installed cost of 1000 heat pumps? Alternately, does $4.8M represent the incremental cost of 1000 heat pumps compared to a baseline fuel oil furnace, natural gas furnace and electric resistance system?

(d) For the "Reliability" impact, the "Basis for Estimation" column includes the description "Should be reflected in Avoided Costs". Please discuss the reliability impact of measures which increase peak load on the electric system, and how reliability should be reflected in the avoided electric system costs for these measures.

(e) Is reflecting reliability impacts in avoided electricity system costs consistent with E1's current practice?

(f) Does E1 propose to consider reliability benefits and/or costs to the electric system associated with fuel switching measures, including measures which increase system or local peak loads?

<u>Request IR-9</u>

Reference: **Appendix B, Textbox 1, Item 8 “EFG also recommends the use of the benefit per kilowatt hour estimates for local non-greenhouse gas air pollutants be based on estimates from the US Environmental Protection Agency for the New England Region. This is an approximation, and if deemed appropriate, more specific analysis of ambient air conditions, dispersion, and health impacts from changes in electric generation in Nova Scotia can be undertaken. (See Figure 4 and Section V).”**

(a) Please explain how benefit per kilowatt hour estimates for local non-greenhouse gas air pollutants are derived by the US Environmental Protection Agency and why estimates for the New England region are an appropriate approximation for use in Nova Scotia.

<u>Request IR-10</u>

Reference: **Appendix B, Table 14**

(a) Please explain why the NEB proxy adders recommended are appropriate for Nova Scotia.

(b) Please describe the potential risk increase to the host customer that is derived from "strategic electrification."

<u>Request IR-11</u>

Reference: **Appendix B, Table 23**

(a) The following table has been generated from Appendix B Table 23. Please confirm whether the projected electricity emissions factors below were used to develop the 2026-2040 values in the “Annual Increased Electric Emissions Metric Tonnes” column of Table 23. If this is not confirmed, please provide the emissions factors used to develop these values.

Year	Emissions Factor (tonnes CO_2e/MWh)
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

(b) Please provide the source of the projected electricity emissions factors for 2026-2040 used in Table 23 and clarify whether these factors represent estimated projections for average annual emissions intensities for the province, marginal emissions intensities based on the generation resources required to meet winter peak, or some other estimate.

(c) Please confirm that the natural gas combustion emissions factor used to develop the 2026-2040 values in the “Annual Avoided Nat Gas Electric Emissions Metric Tonnes” column of Table 23 is 0.180 tonnes CO_2e/MWh (0.050 tonne CO_2e/GJ). If this is not confirmed, please provide the emissions factor used to develop these values.

(d) Please provide the following emissions factors for 2024 or the most recent year available, or provide estimates if these values are not available:

i. Average emissions factor for grid-supplied electricity in Nova Scotia in tonnes CO_2e/MWh.

ii. Marginal 2024 emissions factor for grid-supplied electricity in Nova Scotia in tonnes CO_2e/MWh

(e) Please discuss the appropriateness of using either average or marginal grid electricity emissions factors for the purpose of estimating the emissions increases in the "Annual Increased Electric Emissions Metric Tonnes" column of Table 23.

Request IR-12

Reference: **Appendix B, Page 54 "Both examples assume an approximate representative annual space heating consumption of 80 million BTUs (MMBtu), and an assumed existing system efficiency of 84%, and an average heat pump COP of 2.5."**

(a) Is 84% meant to represent the efficiency of the installed furnace stock, or does it represent the efficiency of a new furnace?

(b) Please discuss the appropriateness of 84% for the furnace efficiency for a natural gas furnace.